Exhibit No.:
Issue(s): Acquisition Adjustment
Electric Allocations Agreement
Regulatory Plan–Power Supply Costs
Market Power
Witness: Michael S. Proctor
Type of Exhibit: Rebuttal
Sponsoring Party: MoPSC Staff
Case No.: EM-2000-369

ON BEHALF OF THE

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

UTILICORP UNITED INC. AND THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EM-2000-369

Jefferson City, Missouri

June, 2000

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[1] References listed under "New Materials" indicate where totally new materials have been included in this filing compared to Michael S. Proctor's filing in Case No. EM-2000-292. The other materials that are not classified as "New Materials" include quantitative differences between the mergers involved in the two cases.

REBUTTAL TESTIMONY

OF

MICHAEL S. PROCTOR

UTILICORP UNITED INC., AND

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. EM-2000-369

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Michael S. Proctor. My business address is 301 West High St., P.O. Box 360, Jefferson City, Mo. 65102-0360.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Missouri Public Service Commission (Commission) as Chief Regulatory Economist in the Electric Department.

Q. WHAT IS YOUR EDUCATION BACKGROUND AND WORK EXPERICENCE?

A. I have Bachelors and Masters of Arts degrees in Economics from the University of Missouri at Columbia, and a Ph.D. degree in Economics from Texas A&M University. My previous work experience has been as an Assistant Professor of Economics at Purdue University and at the University of Missouri at Columbia. Since June 1, 1977, I have been on the Staff of the Commission and have presented testimony on various issues related to weather-normalized energy usage and rate design for both electric and natural gas utilities. With respect to electric issues, I have worked in the areas of load forecasting, resource planning and transmission pricing. I recently served as the Staff Vice Chair of the Market Structure and Market Power working group of the Commission's Task Force on Retail Competition.

Q. WHAT ARE YOUR CURRENT DUTIES IN THE ELECTRIC DEPARTMENT AS CHIEF ECONOMIST?

A. In addition to advising the Staff of the Electric Department on various issues related to weather normalization of sales and rate design, my primary focus has been on the development and structure of Regional Transmission Organizations (RTOs) for the purpose of increasing efficiency and reliability in the supply of electricity. Because of the restructuring of the electric industry toward the increased competitive supply of electricity, I have also focused my attention on the issue of market power within the electric industry.

Q. IN THIS INSTANT CASE, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My rebuttal testimony in this instant case will first address the issue of the correct treatment of the acquisition premium (also called acquisition adjustment or merger premium) with respect to the proposed merger between UtiliCorp United Inc. (UCU) and the Empire District Electric Company (EDE), collectively referred to as the Merger Applicants. Specifically, I disagree with Merger Applicants' witnesses Robert K. Green and John W. McKinney, who argue for recovery of a portion of the acquisition premium as a part of what they call the "regulatory plan." As a policy matter, the Staff has always opposed the inclusion of an acquisition adjustment in revenue requirements.

The second part of my rebuttal testimony will address the Electric Allocations Agreement proposed by Merger Applicants' witness Robert W. Holzwarth. This agreement addresses the allocation of production supply costs from the joint dispatch of power supply resources between Missouri Public Service (MPS, a division of UCU) and EDE, as well as the treatment of merger savings related to power supply costs in the regulatory plan proposed by Merger Applicants' witness John W. McKinney. The final part of my rebuttal testimony will address the issue of the potential for an increase in horizontal and vertical market power from the proposed merger.

Q. HOW DOES YOUR TESTIMONY FILED IN THIS MERGER APPLICATION COMPARE TO THE TESTIMONY YOU FILED EARLIER CONCERNING THE SAME ISSUES IN THE UCU-SJLP MERGER APPLICATION IN CASE NO. EM-2000-292?

A. This testimony is very similar to that filed earlier in Case No. EM-2000-292, and in some sections of testimony it is identical. However, there are some additions in this testimony not found in my previous UCU-SJLP testimony reflecting updated information or unique aspects of the UCU-EDE merger transaction.

CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH RESPECT TO THE ACQUISITION PREMIUM?

A. My rebuttal testimony on the acquisition premium is divided into four subsections. In the first two subsections, an explanation of the components of the acquisition premium is given. In the second two subsections, the policy implications of treating the acquisition premium as a merger cost and allowing rate recovery are discussed.

My *conclusion* is that a new Commission policy of treating the acquisition premium as a merger cost and allowing a recovery of that premium would remove incentives for utilities to minimize the amount of acquisition premiums. Of equal importance is that such a policy would not mirror what occurs for non-regulated businesses. My *recommendation* is that, if the Commission decides to implement a policy of giving incentives for mergers, then such incentives should focus on sharing plans that are implemented over a short period (e.g., three to five years) after the completion of the merger and are independent of the amount of the acquisition premium.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH RESPECT TO THE ELECTRIC ALLOCATIONS AGREEMENT?

A. My *conclusion* with respect to the Electric Allocations Agreement proposed by the Merger Applicants is that the language used is unclear in several major sections. However, it appears that the Merger Applicants' intention is for the Electric Allocations Agreement to incorporate its proposed regulatory treatment of savings in power supply costs. My *recommendation* is that the Electric Allocations Agreement not directly incorporate the regulatory plan, but that it follow an allocation principle of reflecting the opportunity costs for each stand-alone power supply system for determining the appropriate power supply costs for each division.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH RESPECT TO THE REGULATORY PLAN TREATMENT OF SAVINGS RELATED TO POWER SUPPLY COSTS?

A. My *conclusions* with respect to the regulatory plan treatment of savings related to power supply costs proposed by the Merger Applicants are:

1) What the Merger Applicants call energy cost savings represent, in large part, energy cost-related opportunities rather than merger-related savings;

2) The proposed regulatory plan is designed to recover the acquisition premium from retention of all of the savings and energy cost-related opportunities except for approximately $3 million per year over the second five years after the merger is completed;

3) The regulatory plan does not allow MPS customers any sharing of the energy cost-related opportunities over a full ten-year period; and

4) The regulatory plan allocates energy cost-related opportunities from the UCU-St. Joseph Light and Power Company(SJLP) merger to EDE when modifications are made for the UCU-SJLP-EDE merger.

My *recommendation* is that only $6.95 million of the Merger Applicants' estimate of energy cost-related savings be included as merger-related and the Commission deny the Merger Applicants' proposed regulatory plan.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH RESPECT TO MARKET POWER FROM THE MERGER?

A. With respect to increases in horizontal market power from the merger, my *conclusion* is that the proposed merger does not pose a threat with respect to high levels of concentration within the northern region of the Southwest Power Pool (SPP). Because specific studies with respect to market power within load pockets have not been performed, my *recommendation* is that at the time of retail competition, the merged entity be required to submit a market power study that addresses this issue.

With respect to potential vertical market power from the merger, my *conclusion* is that absent a regional transmission authority that is independent of an integrated utility, the integrated utility has significant opportunities to impede the transactions of competitors in generation markets. My *recommendation* is that the merged entity be required to place the determination of availability of transmission service and the pricing of its transmission under an independent regional transmission authority such as the SPP.

I. MERGER-RELATED ACQUISITION PREMIUM

Q. WHAT IS MEANT BY THE TERM "ACQUISITION PREMIUM?"

A. An acquisition premium is defined as the amount paid to shareholders of the company being acquired that is in excess of the net book value of that company's assets. In Mr. Green's direct testimony, he calculates the premium to be the difference between the \$29.50/share offered by UCU and accepted by EDE's shareholders compared to \$13.42/share for the net book value of EDE's assets. With approximately 17.1 million weighted average common shares outstanding, the total amount of the acquisition premium would be

$$[(\$29.50/\text{share})*(17.1 \times 10^6 \text{ shares})]-[(\$13.42/\text{share})*(17.1 \times 10^6 \text{ shares})]$$
$$=$$
$$[\$504.5 \times 10^6]-[\$229.5 \times 10^6]$$
$$=$$
$$\mathbf{\$275 \times 10^6}$$

Q. CAN THIS ACQUISITION PREMIUM BE DIVIDED INTO DISTINCT COMPONENTS?

A. Yes. The acquisition premium can be divided into two distinct components. The first component is the difference between the market price per share and the price per share representing the book value of EDE's assets. The second component is the difference between what will be paid by UCU to acquire EDE and the market price per share. Based on an analysis performed by Staff Witness Charles R. Hyneman of the Accounting Department, at the time EDE shareholders accepted the UCU offer, the market price of their common stock was $21.60/share. Using this price to quantify the two components gives:

Component 1: **Market Value – Book Value**
($21.60/share-$13.42/share)*(17.1 x 10^6 shares) = **$140 x 10^6**

Component 2: **Acquisition Payment – Market Value**
($29.50/share-$21.60/share)*(17.1 x 10^6 shares) = **$135 x 10^6**

Q. IN HIS DIRECT TESTIMONY, DOES MR. GREEN PROVIDE AN EXPLANATION FOR THE ACQUISITION PREMIUM?

A. Yes, at page 14 of his direct testimony Mr. Green provides a brief explanation of the reason that a corporation would be willing to pay above market price to acquire another corporation. However, Mr. Green's testimony gives an incomplete explanation of the difference between acquisition payment and market value and gives no explanation for the difference between market value and book value.

A. DIFFERENCE BETWEEN MARKET AND BOOK VALUE

Q. WHAT IS MEANT BY THE "MARKET VALUE" OF A STOCK?

A. Market price of a stock on a given day is the price at which the stock has traded on that day. Market price is determined by transactions that occur *at the margin* between those holding the stock and willing to sell the stock at a price that is at or below the market price (sellers) and those who are willing to buy the stock at a price that is at or above the market price (buyers). If there are a large number of transactions taking place on any given day, then an individual holder of the stock should be able to sell shares at the market price, and therefore can value the stock at its market price. In this context, the market value of a stock is represented by its market price.

Q. WHAT THEN IS AN EXPLANATION FOR THE DIFFERENCE BETWEEN THE MARKET VALUE AND THE BOOK VALUE OF THE STOCK?

A. For any shareholder, the value of a stock is determined by three fundamental factors:

1) The income the stock is expected to produce;

2) The opportunity cost of alternative investments; and

3) The individual's preference for or aversion to risk.

Stock can produce income either in the form of dividend payments or in the form of capital gains (losses). Opportunity cost from alternative investments represents what the shareholder believes can be earned in income by selling the stock in question and investing in another alternative. Risk is the probability distribution around expected earnings, for both the stock in question as well as for alternative investments. When the Commission sets just and reasonable rates, it makes a determination of the Return On Equity (ROE) as the earnings which shareholders require as a return on the book value of the stock. The allowed ROE is in part determined by what has occurred with market prices of the stock and stocks of similar risk over a recent period of time. In this sense, recent opportunity costs and evaluation of risk are taken into account. Yet a determination of the market valuation of ROE using even recent historical data on market prices gives only a snapshot of a dynamic process that is constantly changing. If, for example, the allowed ROE determined in this manner is actually above what the market requires, then the expected earnings for the utility would be greater than anticipated in the ROE calculation, and the price which shareholders would require in order to offer shares on the market would increase. Economists would call this an upward shift in the supply curve (e.g., a decrease in supply) for the stock. This upward shift in the supply curve will cause the market price for the stock to increase.

The allowed ROE determined from historical data at a given point in time can also be greater than what the market requires at a later time because of a subsequent downward shift in opportunity cost (i.e., earnings potential from alternative investments are falling). In addition, expected earnings for the utility can increase because of cost savings coming from either declining rate base or decreases in annual expenses.

Regulatory lag is the time between these changes occurring and the time the regulatory process implements the results of these changes through new rates. In a world of "perfect regulation," rates would be adjusted each day to reflect changes in ROE from changing market expectations, and there would be no difference between the market value and the book value of the stock. But we do not live in a world of "perfect regulation," and the market adjusts to these imperfections through the daily changes in market prices.

Q. WHEN THE ASSETS OF A UTILITY ARE SOLD, SHOULD THE DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE OF THE STOCK BE INCLUDED AS A RECOVERABLE COST OF THE MERGER?

A. The difference between market value and book value of the stock of the acquired utility should not be considered as a recoverable cost of the merger. The reason is quite simple. If the merger is not detrimental to the public interest, then the earnings potential of the utility being purchased should not get worse due to the merger. Because the market value of the stock represents the market's evaluation of the earnings potential of the utility and since that potential has not become worse, the merger results in the same, if not better, earnings potential for the entity purchasing the utility in question.

To state this differently, if the Commission does not allow rate base to be increased by the amount of the difference between market and book value, then there would be no change in the rate base of the acquired utility. Holding everything else constant, the earnings potential of the acquired utility would not have changed from what existed prior to the merger. If new shareholders could have acquired the stock of the utility at its market price, they would have paid the market's evaluation of the earnings potential of that stock that is either the same or better than what it was prior to the merger. In essence, there is no loss of value to the new shareholders that needs to be recovered through some mechanism designed to increase earnings, such as putting the difference between market and book value in rate base in the form of an acquisition adjustment.

Q. WHILE THE MERGER HAS NOT WORSENED THE EARNINGS POTENTIAL, DON'T EXISTING SHAREHOLDERS HAVE THIS SAME EARNINGS POTENTIAL BUT AT AN INVESTMENT COST EQUAL TO BOOK VALUE THAT IS LOWER THAN THE MARKET PRICE PAID BY THE ACQUIRING ENTITY AND ITS SHAREHOLDERS?

A. No. It is incorrect to assume that existing shareholders paid book value for their shares. In fact, there is no way from publicly available information to measure what existing shareholders paid for their shares, and certainly there is no reason to believe that current shareholders paid book value for their shares. Beyond the question of not knowing what existing shareholders paid for their shares, what they have historically paid for shares is a sunk cost to the investor. Sunk costs are not relevant either to current investment decisions (to sell or not sell shares in the daily market), or with respect to what is required as an offer price to sell their shares to the acquiring entity.

B. DIFFERENCE BETWEEN ACQUISITION PAYMENT AND MARKET VALUE

Q. WHY WOULD THE ACQUISITION PAYMENT BE DIFFERENT FROM MARKET VALUE?

A. Market price is determined based on the supply and demand for the stock on a given day, with quantities being exchanged representing only a small fraction of the total stock outstanding. In order for this merger to take place, at least a simple majority of current shareholders of EDE stock must agree to the sales price being offered by UCU. Acquisition price represents the offer price that is expected to induce at least one-half of current EDE shareholders to sell, based on their overall evaluation of expected earnings, opportunity costs and required risk premiums. While market price represents a price at which a small fraction of shareholders are willing to sell their shares, to increase the willingness to sell from that small fraction to one-half of outstanding shares will demand a higher offer price.

Q. IN YOUR OPINION, WHEN THE ASSETS OF A UTILITY ARE SOLD, SHOULD THE DIFFERENCE BETWEEN ACQUISITION PAYMENT AND MARKET VALUE OF THE STOCK BE INCLUDED AS A RECOVERABLE COST OF THE MERGER?

A. The difference between acquisition payment and market value of the stock of the acquired utility should <u>not</u> be considered to be a recoverable cost of the merger. The reason is the same as for the difference between market value and book value. In essence, while the market value represents the value placed on future earnings at the margin, the acquisition payment represents the value placed on future earnings by at least one-half of the existing shareholders. In essence, each individual shareholder makes an evaluation of the price at which he or she would sell his or her stock based on expectations of future earnings, opportunity cost of other investments and risk preference. If ranked from lowest to highest asking price, the lowest asking price would be slightly above the current market price and the acquisition price would be at or above the asking prices for one-half of current shareholders.

There are additional similarities between the determination of the market price and the acquisition price on the demand side of the offer. In the case of market price, the investors are looking at alternative investment opportunities and making offers based on their evaluation of those opportunities relative to earnings for the specific company in question. Likewise, companies that are considering mergers or acquisitions are looking at alternative investment opportunities and set their bid price based on what they see as their opportunity costs in the market compared to their earning potential from the utility on which the offer is made. The reason that a company seeking to merge is willing to make an offer that is higher than what the rest of the investment market is willing to offer is that it sees higher earnings potential, has a lower opportunity cost or has a different risk preference.

C. POLICY IMPLICATIONS FROM ALLOWING THE RECOVERY OF THE MERGER ACQUISITION PREMIUM

Q. IN NON-REGULATED BUSINESSES, DOES THIS FUTURE EARNINGS POTENTIAL INCLUDE SOME RECOVERY OF THE

DIFFERENCE BETWEEN ACQUISITION PAYMENT AND EITHER MARKET VALUE OR BOOK VALUE OF THE STOCK?

A. No, non-regulated businesses do not operate in this fashion. Instead, they would simply look at the earnings potential from acquiring the business and compare that to other opportunities in making a decision as to how much to offer to acquire the business in question. If that offer were accepted, then the merger would take place subject to the approval of the Securities and Exchange Commission (SEC). However, it is important to realize that if there are synergies from the merger that will increase the earnings potential of the merged company when compared to the separate companies, that increase in earnings potential can play a role in the price that the acquiring company is willing to offer the shareholders of the company being acquired.

Q. IN WHAT WAYS DOES THIS COMPARE TO WHAT HAPPENS WITH REGULATED COMPANIES?

A. There should be no difference. The company seeking to acquire a regulated company must perform an evaluation of the expected earnings it anticipates from that company including some expectation of increased earnings from the synergies anticipated from the merger. Based on this evaluation, the company determines the price per share that it is willing to offer the regulated company's shareholders. If that price were accepted, then the merger would take place subject to regulatory approval. The difficult part of this comparison is determining what expectations the acquiring utility should have concerning increased earnings from the synergies anticipated from the merger.

It is important to note that this order of causality problem needs to be divided into the correct causal sequence. The incorrect causal chain is the one presented by UCU in its testimony, which is: *the acquisition premium causes a certain level of recovery of the synergies from the merger.* The correct causal chain is that: *a certain level of recovery of the synergies from the merger causes a cap on the offer price for the acquisition.*

Q. WHAT THEN IS THE IMPACT OF A POLICY THAT WOULD BASE THE LEVEL OF RECOVERY OF SYNERGIES FROM THE MERGER ON THE LEVEL OF THE ACQUISITION PREMIUM?

A. The effect of such a policy would be an increase in the price that companies would be willing to offer to merge with other companies. Suppose there were several companies bidding to acquire the regulated company. With a "known" regulatory policy of allowing recovery of an acquisition premium, all of the companies would be willing to bid higher because of the higher expected earnings that would result from there being a regulatory policy of allowing the recovery of the acquisition premium. The expected synergies from the merger should place a cap on what any company would be willing to offer, but if recovery of the acquisition premium is included in those potential earnings, what should be the true cap on bids is no longer relevant. In non-regulated mergers, the bidding would stop when the company expecting the next to highest synergies from the merger was no longer willing to bid. But when recovery of the acquisition premium is "guaranteed" as a regulatory policy, it is impossible to determine where the bidding will stop.

Q. WOULD HIGHER ACQUISITION PRICES RESULT IN MERGERS TAKING PLACE THAT MIGHT NOT OTHERWISE TAKE PLACE?

A. Yes. It is very likely that a regulatory policy that allows recovery of the acquisition premium and fosters offering higher acquisition prices would result in more mergers being proposed. However, this is not a good thing. As a general economic principle, whether or not a merger should take place should be based on the potential economic gain in the market from the merger, and not on a regulatory policy of adding earning incentives to the market through allowing recovery of an acquisition premium. In effect, regulatory policy should be based on a parallel to what would happen in competitive markets, and as indicated above, mergers in non-regulated businesses offer no recovery of an acquisition premium.

Q. WOULD A POLICY OF NOT ALLOWING THE RECOVERY OF AN ACQUISITION PREMIUM RESULT IN MERGERS NOT TAKING PLACE THAT OTHERWISE WOULD HAVE RESULTED IN SAVINGS TO RATEPAYERS?

A. A merger where the offered acquisition premium is based on the assumption of recovery of the acquisition premium may not be consummated if there is regulatory denial of the acquisition premium. However, such a situation is not relevant for Missouri because this Commission has not previously allowed recovery of an acquisition premium and therefore it would be presumptuous to make an offer based on the assumption of recovery.

D. POLICY IMPLICATIONS AND VARIOUS METHODS FOR SHARING MERGER SAVINGS

Q. DO YOU THEN CONCLUDE THAT THERE SHOULD BE A POLICY OF NOT ALLOWING UTILITIES ANY RETENTION OF THE SYNERGIES FROM THE MERGER?

A. No, that is not my conclusion. The Commission may allow some sharing of the savings from the merger between shareholders and ratepayers. But any policy of sharing merger savings should not be based on the amount of the acquisition premium that was agreed to prior to obtaining regulatory approval of the merger. There are other options available for sharing the savings. For example, regulatory lag allows the merged utility the opportunity to recover some of the merger savings. Likewise, a rate freeze (moratoriums on rate increase/earnings complaint cases) over a three- to five-year period after the merger is completed allows companies (in declining cost circumstances) the opportunity to pay off the merger costs and retain a portion of the immediate savings resulting from the merger. After the rate freeze period, the Staff would file a complaint case to lower rates to match the lower cost levels, including capturing the actual merger savings that are in place at that time. This rate freeze period also allows the merged entity the time it needs to implement its merger plan and begin to accrue some of the merger savings.

Q. IS A THREE- TO FIVE-YEAR RATE FREEZE A POSSIBLITY FOR MERGERS INVOLVING MISSOURI PUBLIC SERVICE?

A. With the addition of significant levels of new purchased power and new leases on generation capacity that are replacing older, lower-cost contracts, it appears that MPS is not in a declining cost situation over the next three to five years. This means that even with the opportunity for merger savings, MPS is likely to file for a rate increase sometime within the next three years. Thus, a rate freeze over a three- to five-year period after the consummation of the merger does not appear to be a viable alternative for MPS. On the other hand, upon the addition of Empire's State Line combined cycle unit and a rate case to incorporate the costs of the added generation, EDE may be in a position where a rate freeze over a three- to five-year period could be applied.

Q. WHEN A RATE FREEZE IS NOT FEASIBLE, WHAT OTHER ALTERNATIVE REGULATORY PLANS CAN BE IMPLEMENTED FOR SHARING MERGER SAVINGS BETWEEN SHAREHOLDERS AND RATEPAYERS?

A. Sharing plans require a determination of three elements. The first element is whether or not the merger savings that are shared are based on estimates made prior to the merger (*ex ante*), or will depend on after-the-fact measurements (*ex post*). The second element is the percentage sharing between shareholders and ratepayers that will be applied. The third element is the length of time over which the sharing of the savings would apply.

Q. CAN YOU ILLUSTRATE HOW THESE VARIOUS DETERMINANTS WOULD ACTUALLY APPLY?

A. Yes. For the first illustration assume that it is determined that an *ex ante* estimate of merger savings will be used, that there will be a 50% sharing between shareholders and ratepayers and that this sharing will apply for a five-year period. Putting this in the context of MPS with increasing costs, after the merger is completed and before the five-year sharing period is up, any MPS filing for a rate increase would add to actual costs an amount equal to 50% of the estimated annualized merger savings. After the five-year sharing period, this adder would not be included in MPS's cost of service. Changing either the percentage or the period of time has an obvious impact. The higher the percentage going to shareholders and/or the longer the period of time, the greater will be the amount of overall merger savings going to shareholders and resulting in higher rates.

Q. IF THIS *EX ANTE* PROCEDURE IS FOLLOWED, IS THERE ANY GUARANTEE OF ACTUAL SAVINGS FROM THE MERGER?

A. With the *ex ante* approach, there is no guarantee of actual savings from the merger. If actual costs go up from the merger and the benefits expected in terms of savings do not occur, then the utility's costs are higher than what was projected for the merger. To make matters worse, on top of these higher costs are added the 50% of so-called shareholder "savings." In essence, *ex ante* procedures put the ratepayer at risk by adding *certain costs* that are to be offset by *uncertain savings* and providing no incentives for utilities to achieve those savings. I would characterize such a plan as being detrimental to ratepayers' interest.

Q. HOW DOES THE *EX POST* PROCEDURE WORK?

A. For the second illustration, instead of using an *ex ante* estimate of annualized merger savings, the merger savings would be estimated *ex post* for the test year of the rate case. The word "estimated" *ex post* savings is used, rather than "measured" *ex post* savings, on purpose. Because merger savings are the difference between what would have happened without the merger and what actually happened, and since what would have happened without the merger is not measurable, it is impossible to measure merger savings on an *ex post* basis. Unless very explicit formulas for estimating merger savings *ex post* are set out ahead of time, any future rate case that includes merger savings will involve additional testimony regarding each party's estimate of the merger savings. Thus, one of the major drawbacks of the *ex post* approach is the difficulty in the regulatory process to make a determination of merger savings.

To illustrate where *ex post* estimates of merger savings might be used, an example is in the energy cost savings that come from joint dispatch of generation. In this application, methods for estimating the energy costs savings from joint dispatch are set out as part of the regulatory plan. This would involve assumptions regarding the estimation of what energy costs would have been without the joint dispatch and comparing them to what these costs are with the joint dispatch. Estimating what energy costs would have been without the joint dispatch depends on applying certain assumptions about what the test year would have been absent the merger. As I will discuss later in my testimony, there is no way to determine whether or not such assumptions are valid.

Q. SHOULD *EX POST* ESTIMATES BE COMPARED TO EXPECTED MERGER SAVINGS?

A. Generally, it is a good idea to combine the *ex ante* and *ex post* estimation of merger savings. This approach is what could be termed *benchmarking.* Benchmarking simply means that *ex post* estimates of historical test year costs are compared to the *ex ante* estimate of what these costs were expected to be. In addition to an *ex ante* estimate of merger savings, benchmarking also requires an *ex ante* estimate of what the cost will be without the merger (forecasts of future budgets without a merger). The sum of these two *ex ante* estimates provides a benchmark against which actual test year costs are measured. For example, suppose overhead costs for two utilities are estimated to be $15 million prior to the merger and with the merger a claim is made for an expected $3 million in savings. Thus, the *ex ante* estimate of overhead costs is $12 million. After the merger is completed, MPS files a rate case and the overhead costs are $13 million rather than the estimated $12 million. Instead of sharing 50% of the $3 million in expected merger savings by adding $1.5 million to its test year cost of service, MPS is required to subtract 50% of the difference between estimated and actual test year overhead costs from what is added for purposes of merger savings sharing. Specifically, instead of adding $1.5 million to its test year costs, it can only add $1.5 million minus 50% of the difference between $13 million actual and $12 million estimated (0.5*(13-12) = $0.5 million). In this example, instead of adding $1.5 million to the $13 million in overhead expense ($1.5+$13.0 = $14.5), MPS can only add $1 million to the $13 million in overhead expense, putting $14 million into test year revenue requirements rather than $14.5 million. Notice that this is equivalent to measuring the savings as being the difference between projected costs of $15 million and test year costs of $13 million, and allowing 50-50 sharing on the difference of $2 million.

On the other side of benchmarking, if the utility does better than the benchmark, it is allowed to increase the adder by 50% of the difference. For example, if test year expenses are $11 million dollars, $1 million below the benchmark of $12 million, then MPS is allowed to add 50% of this $1 million to the $1.5 million of shareholders' share of expected savings. Thus, the test year revenue requirements for overhead expense would be the test year expense of $11 million plus the $1.5 million of shareholders' share of expected savings plus the $0.5 million for being below the benchmark. The total included in revenue requirements would be $13 million. Again, notice the same results are reached by measuring the savings as being the difference between projected costs of $15 million and test year costs of $11 million, and allowing 50-50 sharing on the difference of $4 million.

The policy concept behind benchmarking is that it gives the utility an additional incentive to maximize merger savings. This type of policy is most appropriate with respect to costs that can be fairly closely controlled by the utility, such as the number of employees working in the overhead functions.

Q. IS THE BENCHMARKING PROCEDURE PREFERABLE TO EITHER *EX ANTE* OR *EX POST* PROCEDURES?

A. In my opinion, benchmarking is preferable because it holds the utility to the estimates of savings used to justify the merger. The difficulty with benchmarking is in making a determination that the forecasted budget levels for costs absent the merger are reasonable.

Q. ARE THERE OTHER ALTERNATIVES THAT AVOID THE PROBLEMS OF ESTIMATING SAVINGS FROM THE MERGER?

A. Yes, there are. However, these approaches involve what are called either "*alternative regulation*" plans, "*incentive ratemaking*" plans or *"performance-based ratemaking"* plans. An example of this approach is the settlement approved by the Commission for the Union Electric Company merger with Central Illinois Public Service to form Ameren. In this regulatory sharing plan, after a one-time rate decrease, electric rates were frozen and there was a grid by which profits above certain levels were to be shared between shareholders and ratepayers. The problems of the inability to measure merger savings were circumvented by not attempting to measure such savings. Instead, the focus of this type of regulatory sharing plan is on measurement of overall earnings. In essence, an alternative form of regulation was used to allow Union Electric Company to recover some portion of the estimated savings from the merger. An initial three-year sharing plan was in effect at the time of the merger, and this sharing plan was extended an additional three years after agreement for a rate decrease reflecting the average level of savings over the first three years.

The type of regulatory sharing plan implemented for Union Electric Company is not directly related to the merger or to merger savings. In essence, these types of sharing plans can just as easily be used for any utility as alternatives to traditional rate of return regulation. The advantage of alternative regulation plans is that they do not isolate and attempt to track specific elements of cost.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT SOME FORM OF REGULATORY SHARING PLAN FOR THE PURPOSE OF THIS MERGER?

A. No. The purpose of my rebuttal testimony is to explain attributes associated with various types of regulatory sharing plans. Staff witness Mr. Mark L. Oligschlaeger of the Accounting Department will testify on the Staff's recommendation regarding regulatory sharing plans.

II. MERGER SAVINGS IN POWER SUPPLY COSTS

Q. WHAT FORMS OF SAVINGS IN POWER SUPPLY COSTS DO THE MERGER APPLICANTS ESTIMATE WILL RESULT FROM THE MERGER OF UCU AND EDE?

A. There are several components to the proposed merger savings for power supply costs. First, with respect to the joint dispatch of the generation of MPS and EDE, there are potential short-run savings with respect to the cost of fuel and purchased power net of sales. These savings can be divided into three basic subcategories: a) savings in fuel and variable operating costs; b) savings in interchange (off-system) purchased power costs; and c) greater profitability in interchange (off-system) sales.

Second, with respect to the joint capacity planning for the merged utilities there are potential savings from combining the loads for purposes of determining peak load capacity requirements. These savings are specifically related to the diversity of load (the assumption that the MPS and EDE loads do not reach their peaks at the same time).

Third, it is important to point out that potential savings from joint dispatch will not be possible without additional expenditures on transmission required to connect the MPS and EDE systems.

My rebuttal testimony on proposed savings on power supply costs focuses on how to estimate and allocate the various common costs related to power supply. This testimony is divided into three parts:

A. Electric Allocations Agreement;

B. Regulatory Plan; and

C. Effects of the proposed merger with SJLP.

A. ELECTRIC ALLOCATIONS AGREEMENT

Q. WHAT IS A JOINT DISPATCH AGREEMENT AND WHY IS IT IMPORTANT TO THE ISSUE OF CALCULATING SAVINGS IN SHORT-RUN GENERATION COSTS?

A. A joint dispatch agreement specifies how the generation and long-term power contracts of the separate companies or divisions will be used to meet the overall native load requirements. "Native load" includes both retail loads served under State Commission tariffs and wholesale loads that are either under contract or are served on a

Federal Energy Regulatory Commission (FERC) tariff. This is the load that the utilities are obligated to serve with their power supply resources.

In addition to specifying how power supply resources will be used, the joint dispatch agreement specifies how the costs resulting from the use of these resources will be allocated among the various divisions; *e.g.*, MPS and EDE. This is important if the merged entity intends to continue to use separate rates for each division and yet treat power supply as a common cost through jointly dispatching the separate power supply resources. It should be noted that there are other divisions of UCU, such as West Plains, that are not included in the joint dispatch agreement.

When the merging companies attempt to retain a pre-merger company identity under a holding company, as was done with AmerenUE and AmerenCIPS, which are subsidiaries under Ameren, the joint dispatch agreement is an agreement to dispatch each subsidiary's power supply resources as if there were only one company. In the proposed merger between UCU and EDE, the result will be only one company with two divisions, and the joint dispatch agreement is called an Electric Allocations Agreement.

Q. IN THIS CASE, WHAT IS THE PROPOSED ELECTRIC ALLOCATIONS AGREEMENT?

A. The Merger Applicants have included a proposed Electric Allocations Agreement in Schedule RWH-10, attached to the direct testimony of Robert W. Holzwarth. At page 18 of his direct testimony, Mr. Holzwarth brings out three main elements:

1. Allocation of Existing Capacity Costs. "Existing generation capacity costs and purchased power capacity costs will remain with the entity which owned or had contracted for such capacity prior to the closing of the merger."

2. Allocation of New Capacity Costs. "New generation and/or purchased capacity and associated cost will be assigned to each entity on the basis of the capacity needs of each entity. The assignment will be on an equal cost per kilowatt basis."

3. Allocation of Energy Costs. "The power supply portfolio of the combined entity will be dispatched in a manner to minimize the overall power supply cost of the combined system. Energy savings achieved will be allocated to EDE since none of the savings would be possible absent the merger."

In addition, energy savings will be determined for two separate components as follows:

1. On-System Energy Savings. A computer production-costing model will be calibrated to duplicate the actual joint dispatch of power supply resources. That model will then be rerun on a stand-alone basis. The results of the joint dispatch will be subtracted from the sum of the stand-alone dispatches to determine the on-system energy savings.

2. Margins from Off-System Sales. Records will assign each off-system sale to a specific power supply resource for purposes of calculating the profit margin. Additional profit margins from off-system sales will be assigned to EDE.

Q. DO YOU AGREE WITH THE DETERMINATION AND THE ALLOCATIONS OF CAPACITY COST SAVINGS PROPOSED BY THE MERGER APPLICANTS?

A. Yes, I do. It is reasonable for a period of time after the merger to keep divisional costs based on the historical capacity costs of the existing generation facilities. It is also reasonable on a going-forward basis, to combine and allocate the capacity costs of new generation facilities being brought on line to meet the joint peak load and reserve requirements of the merged utilities.

Q. DO YOU AGREE WITH THE DETERMINATION AND THE ALLOCATIONS OF ENERGY COST SAVINGS PROPOSED BY THE MERGER APPLICANTS?

A. No, I do not. The primary source of the Staff's disagreement with the allocations of energy cost savings proposed in the Electric Allocations Agreement is because the proposal has not explicitly treated the concept of opportunity cost. I will illustrate this deficiency using three examples of a joint dispatch involving two utilities. In all three illustrations, the incremental and decremental costs for energy from internal (on-system) power supply resources for each utility to meet native load do not change. What changes in each of the three illustrations is the market price for off-system (wholesale) purchases or sales of energy.

Q. WHAT DO YOU MEAN BY DECREMENTAL COSTS FROM SERVING NATIVE LOAD?

A. Blocks of hourly energy from available on-system power supply resources are stacked in order of lowest to highest variable energy cost to serve native load. The first block of decremental cost is then defined as the cost savings that would occur when the highest energy cost block from on-system power supply resources required to serve native load is removed from the stack. Further blocks of decremental costs are calculated as the cost savings due to removing additional blocks of on-system power supply resources from the stack. The decremental costs per unit of each additional block of power are typically lower and should not be any higher than the decremental cost of the previous block. An off-system purchase is made as a substitute for on-system power supply resources when the price of off-system power is lower than the decremental cost of serving the load with on-system power supply resources.

Q. WHAT ARE THE INCREMENTAL COSTS TO SERVING NATIVE LOAD?

A. Blocks of hourly energy from available on-system power supply resources are stacked in order of lowest to highest variable energy cost to serve native load. The first block of incremental cost is then defined as the additional cost that would occur when the next higher energy cost block from on-system power supply resources is added to the stack required to serve native load. Further blocks of incremental costs are calculated as the additional cost due to adding additional blocks of on-system power supply resources to the stack. The per-unit incremental costs of each additional block of power are typically higher and should not be any lower than the incremental cost of the previous block. In addition, the lowest per-unit incremental cost is typically higher and should not be any lower than the highest per-unit decremental cost. An off-system sale is made from internal power supply resources when the price of off-system power is above the incremental cost of the power supply resources that are not being used to serve native load.

Q. WHAT DO YOU MEAN BY THE MARKET PRICE FOR OFF-SYSTEM ENERGY?

A. The market for off-system energy is also called the wholesale spot market for electricity. It is the market, in which traders buy and sell electricity. In the illustrations that follow, it is assumed that there is a single market with a price established at which both utilities can buy or sell whatever quantities they wish. "Market clearing price" means the price at which demand and supply are equal. If the price is above market price, then suppliers will want to sell more than buyers wish to purchase, thereby causing the price to fall. If the price is below market price, then buyers will want to purchase more than suppliers wish to sell, thereby causing the price to increase.

Q. WHAT IS YOUR FIRST ILLUSTRATION OF JOINT DISPATCH?

A. The first illustration is set out as Case 1 in Schedule 1, where the price of off-system power is below the decremental costs of one of the utilities and below the incremental costs for both utilities. The market price for off-system power is $18/MWh, while Utility B's decremental costs are $25/MWh for the first 100 MWhs and $20/MWh for the next 100 MWhs. Beyond the first 200 MWh, Utility B's decremental costs are assumed to be at or below $18/MWh. Utility A's decremental costs are at or below $18/MWh, and both utilities' incremental costs are above $18/MWh.

In this case, the stand-alone costs and the joint dispatch costs for the two utilities are the same. Utility A neither purchases nor sells off-system, and Utility B replaces the 200 MWh of more expensive power with off-system purchases from the wholesale market. Notice in this case, there are savings from purchasing off-system, but these savings would have occurred absent the merger. Therefore, there are no merger-related energy savings, and since there are no off-system sales, there are no profits to be determined or allocated. In this simple case, the proposed Electric Allocations Agreement would properly dispatch and allocate costs, but almost any reasonably written allocations agreement would handle this simple case the same way.

Q. WHAT IS YOUR SECOND ILLUSTRATION OF JOINT DISPATCH?

A. The second illustration of joint dispatch is Case 2 found on Schedules 2.1 and 2.2 attached to my rebuttal testimony. This illustrates a case in which the market price is between decremental and incremental costs. The market price for off-system power is $23/MWh, which is above the incremental cost of $20/MWh for Utility A, and below the decremental cost of $25/MWh for Utility B.

On a stand-alone basis, Utility A would sell 100 MWh to the market making a profit on the difference between the market price and its incremental energy cost of \$23/MWh - \$20/MWh = \$3/MWh, for a total profit of \$3/MWh x 100 MWh = \$300. Utility B would purchase 100 MWh from the market resulting in a savings on the difference between its decremental energy cost and the market price of \$25/MWh - \$23/MWh = \$2/MWh, for a total savings of \$2/MWh x 100 MWh = \$200.

On a joint dispatch basis, the incremental generation from Utility A will be substituted for the decremental generation from Utility B, resulting in an internal energy cost savings of \$25/MWh - \$20/MWh = \$5/MWh, for a total savings of \$5/MWh x 100 MWh = \$500. After this joint dispatch, Utility A's revised incremental cost is the cost of the next block not being dispatched to meet either its own native load or the native load of Utility B. This incremental cost is \$25/MWh. After the joint dispatch, Utility B's revised incremental cost is the decremental cost of the block of power taken out of the dispatch to make room for the cheaper block of power from Utility A. Thus, Utility B's incremental cost is \$25/MWh. Both incremental costs are above the market price for electricity, and no sales will be made to the market from the joint dispatch.

Q. HOW WOULD THE PROPOSED ELECTRIC ALLOCATIONS AGREEMENT CALCULATE INTERNAL ENERGY COST SAVINGS?

A. It appears that the proposed Electric Allocations Agreement would calculate internal energy cost savings to be \$500, and would allocate all of that savings to whichever of the two utilities is EDE.

Q. HOW WOULD THE PROPOSED ELECTRIC ALLOCATIONS AGREEMENT CALCULATE PROFIT MARGIN FROM SALES?

A. Here is where the proposed Electric Allocations Agreement is not clear. At page 19 of Mr. Holzwarth's direct testimony, he interprets the language of the Electric Allocations Agreement to say, "The margins from off system sales to be assigned to Empire since none of the additional margins would have occurred absent the merger." I don't know what this statement means. There are two possible ways to interpret the language in the proposed Electric Allocations Agreement:

1. The profits from sales are calculated and allocated separately from the energy cost savings when comparing the joint and stand-alone dispatches.
2. The profits from sales are included in the calculation of the energy cost savings when comparing the joint and stand-alone dispatches.

My rebuttal testimony is that the former approach is incorrect and the latter approach is correct.

Q. WHY DO YOU DISAGREE WITH THE CONCEPT OF SEPARATING THE CALCULATION AND ALLOCATION OF INTERNAL ENERGY COST SAVINGS FROM THE CALCULATION AND ALLOCATION OF PROFIT MARGINS?

A. A calculation of energy cost savings that does not include profit margins from sales as an offset to energy costs fails to take into account the opportunity cost for the utility that foregoes a sale in order to provide generation to another utility. In Case 2, when Utility A substitutes 100 MWh of its $20/MWh generation for the $25/MWh generation of Utility B, it foregoes the opportunity of selling that 100 MWh's to the off-system energy market at $23/MWh and making a profit of $300. Subtracting the $300 in opportunity cost from the $500 of total internal energy savings leaves $200 in savings to Utility B. Notice that this is the same savings that Utility B would have realized by buying the substitute block of power in the off-system energy market. Thus, there are zero additional savings generated by the joint dispatch of the two systems.

If on the other hand, the net energy cost savings is calculated by subtracting the profits from sales from the costs incurred by the utilities, it becomes clear that there are zero savings from the joint dispatch. This is shown in the second table on Schedule 2.1. For the stand-alone dispatch, the net savings is $300 in profit for Utility A and $200 in internal energy cost savings for Utility B, giving an overall savings from the market of $500. For the joint dispatch case, Utility A's internal generation costs go up by $2,000 and Utility B's internal generation costs go down by $2,500, giving an overall savings from the joint dispatch of the same $500. Subtracting the stand-alone costs from the joint dispatch costs will therefore yield a net savings of zero.

Q. IN THIS ILLUSTRATION, GIVEN THE PROPER CALCULATION OF ENERGY COSTS FOR BOTH THE JOINT DISPATCH AND STAND-ALONE CASES TO INCLUDE PROFITS FROM SALES, WHAT THEN IS THE PROPER ALLOCATION OF COST FROM THE JOINT DISPATCH?

A. For Case 2, Schedule 2.2 shows a summary of the stand-alone and joint dispatch results, sets out the proper joint dispatch allocation rule, and shows the results of applying that rule. The joint allocation rule represented on this Schedule requires the utility receiving the generation from another utility to pay that utility both its incremental generation costs and its loss of profits. Because there are no savings compared to the stand-alone case, the joint dispatch allocation rule results in both utilities paying their stand-alone costs.

Q. DOES THIS SAME RESULT HOLD WHEN THE MARKET PRICE IS ABOVE THE INCREMENTAL COSTS FOR BOTH UTILITIES?

A. Yes, it does. This is illustrated in Case 3 on Schedules 3.1 and 3.2. The market price for off-system energy is \$30/MWh, which is above Utility A's incremental cost of \$20/MWh for the first 100 MWh, \$25/MWh for the next 100 MWh block and \$28/MWh for the third 100 MWh block. The \$30/MWh market price is also above Utility B's incremental costs of \$25/MWh for the first 100 MWh.

In the stand-alone case, both utilities will sell into the off-system energy market at a price of \$30. Utility A will make a different per unit profit on each 100 MWh block (i.e., \$10/MWh = \$30/MWh - \$20/MWh for the first 100 MWh, \$5/MWh = \$30/MWh - \$25/MWh for the next 100 MWh, and \$2/MWh = \$30/MWh - \$28/MWh for the third 100 MWh block). The overall profit for Utility A is \$1,000 + \$500 + \$200 = \$1,700. Utility B will make a per unit profit of \$30/MWh - \$28/MWh = \$2/MWh, giving a total profit of \$200 on its 100 MWh sale. Thus, savings from the market in the stand-alone dispatch case is \$1,700 + \$200 = \$1,900.

In the joint dispatch case, the \$20/MWh of incremental cost from Utility A is substituted for the \$25/MWh decremental cost from Utility B. Then Utility A sells 200 MWh to the market at an incremental cost of \$25/MWh for the first 100 MWh and \$28/MWh for the second 100 MWh. At a sale price of \$30/MWh, Utility A's profits from this sale are \$500 + \$200 = \$700. Also, Utility B can sell 200 MWh to the market at an incremental cost of \$25/MWh for the first 100 (what was initially decremented for Utility A's cheaper energy) and \$28/MWh for the second 100 MWh. At a sale price of \$30/MWh, Utility B's profits from this sale are also \$500 + \$200 = \$700.

On Schedule 3.2, comparing the stand-alone to the joint dispatch case shows that the overall incremental generation is the same as well as the incremental generation costs. Also, notice that the overall sales to the market of 400 MWh are the same, giving the same revenues. Thus, the total cost net of profits will be the same for the joint dispatch and the stand-alone dispatch, and the savings from joint dispatch are zero.

Q. IS IT YOUR REBUTTAL TESTIMONY THAT WHEN PROFITS FROM SALES ARE SUBTRACTED FROM THE COSTS FOR BOTH THE STAND-ALONE AND JOINT DISPATCHES, THE ANSWER WILL ALWAYS BE ZERO SAVINGS?

A. Yes. When the Electric Allocations Agreement specifies that: "Generating unit and interchange parameters, as developed in the joint dispatch model (step b. above) will be used as input data for the stand alone production cost simulations to be done for each Company," the calculated answer will always be zero savings. However, I should note that in the sentence following the above quote, the proposed Electric Allocations Agreement also states: "In addition, own load re-dispatch will reflect pre-merger operating practices and conditions." Thus, it appears that some modifications to the stand-alone dispatches are anticipated, but apparently not to generating unit or interchange parameters.

Q. WHEN THE MERGER APPLICANTS CALCULATED EXPECTED MERGER SAVINGS FROM THE JOINT DISPATCH, DID THEY ALSO SUBTRACT PROFITS FROM THEIR CALCULATION OF BOTH JOINT DISPATCH AND STAND-ALONE COSTS TO ESTIMATE ENERGY COST SAVINGS?

A. Yes, they did. This is the proper way to include opportunity cost in the calculation of possible merger savings. Based on calculations made by Staff witness Mr. Tom Lin of the Electric Department, the estimated difference in energy cost between the stand-alone and joint dispatch is $164 million for the ten-year period 2001 through 2010 compared to the Merger Applicants' estimate of $156 million.

Q. HOW DID THE MERGER APPLICANTS THEN CALCULATE FAIRLY HIGH LEVELS OF ENERGY COST SAVINGS FROM THE JOINT DISPATCH?

A. A significant portion of the merger-related energy cost savings calculated in the Merger Applicants' estimate reflects an assumption of a greater availability and level for sales in the off-system energy market for the joint dispatch case compared to the stand-alone case. From 2001 to 2010, profits from off-system energy sales totaled $295 million in the joint dispatch model.

Q. WHAT IS YOUR UNDERSTANDING OF THE LIMITATIONS THAT THE MERGER APPLICANTS PLACED ON SALES OPPORTUNITIES FOR THE STAND-ALONE DISPATCHES?

A. The Merger Applicants limited the availability of sales opportunities through the use of an outage rate for MPS and EDE and a limit on the amount of sales for EDE. Mr. Lin will discuss the details of these limits in his rebuttal testimony. My understanding is that these limits were set to reflect current sales levels in the off-system energy markets for MPS and EDE.

Q. DO YOU AGREE THAT CURRENT SALES LEVELS ARE A REASONABLE MEASURE TO USE FOR SALES OPPORTUNITIES FOR MPS AND EDE ON A STAND-ALONE BASIS FOR THE NEXT TEN YEARS?

A. No, I do not. In particular, EDE is adding combined cycle capacity through its current capacity expansion plan. As this capacity is added, additional lower-cost energy will be available for EDE to sell in the off-system energy market, and I would expect EDE to be more aggressive in the off-system energy markets on a stand-alone basis.

Q. HOW MUCH OF THE SYNERGIES CLAIMED BY THE MERGER APPLICANTS ARE ATTRIBUTABLE TO EXPANDED SALES OPPORTUNITIES IN THE OFF-SYSTEM ENERGY MARKET?

A. When comparing profits from the joint dispatch to the profits from the stand-alone dispatches where sales opportunities are limited to current levels, I found that over the ten year period, of **$295 million** in profits from sales, the stand-alone case with limited sales opportunities attributes **$175 million** to pre-merger limited sales opportunities, leaving **$120 million** to post-merger expanded sales opportunities.

Since this $120 million in additional profits from sales in off-system energy markets does not account for the total energy cost savings of $164 million, I asked Mr. Lin to make additional stand-alone and joint dispatch runs that totally excluded the possibility of sales in the off-system energy market. The difference between these two runs was $44 million. A summary of each of the components of generation synergies claimed by the Merger Applicants is included in the following table:

Table 1: Power Supply Cost Differences by Source

Source	5 Year Level	10 Year Level
Joint Dispatch-No Sales	$19,154,185	$43,590,596
Expanded Sales	$47,059,844	$120,429,090
Total	**$66,214,031**	**$164,019,689**

Q. IN WHAT SENSE ARE THE $44 MILLION IN SYNERGIES FROM JOINT DISPATCH RELATED TO THE MERGER APPLICANTS' ASSUMPTION REGARDING EXPANDED SALES OPPORTUNITIES FOR THE MERGED ENTITY?

A. In a perfectly competitive off-system energy market, there would be no need for joint dispatch of the merged power supply systems. This is illustrated in Schedules 2 and 3, where it is clear that with a perfect off-system energy market, there is no difference in overall costs between the stand-alone dispatches and the joint dispatch. However, the off-system energy market is not perfect. In a perfectly competitive market, the amount offered by any individual supplier has no discernible effect on the market-clearing price. This is not necessarily the case for wholesale energy markets. Therefore, on a stand-alone basis, the energy-cost reductions truly available from the market may only represent, for example, 90% of the energy-cost reductions available from joint dispatch. In this example, 90% of energy-cost reductions would be attributable to the off-system energy market opportunities and 10% to joint dispatch. There is no way to determine on either an *ex ante* or *ex post* basis what the exact percentage distribution is between these two components.

Q. IN YOUR OPINION, IS THERE ANY GOOD WAY TO INCLUDE THE DIFFERENCES IN SALE OPPORTUNITIES FOR THE MERGED UTILITY IN AN *EX POST* CALCULATION OF ENERGY COST SAVINGS?

A. I cannot think of any good way to do this. Let me explain my answer in terms of the potential complexities of attempting to make such a calculation. In the Midwest, off-system energy markets for power are based on bilateral transactions between specific sellers and specific buyers. At this time the Midwest does not have a centralized spot market for electricity. Thus, one possible form of expanded opportunities comes from an expanded scope and information base for the traders. In this regard, I should note that the traders for UCU as a regulated entity should be identified in the Electric Allocations Agreement as being devoted to serving the regulated business and therefore separate from any other unregulated power marketing divisions of UCU. UCU believes that it is more aggressive in the trading of electricity than EDE, and therefore, post merger, it will find more opportunities for energy trades. Because there will be only one power marketing group after the merger, there is no way in which greater power marketing opportunities can be measured and proven subsequent to the merger. I am not saying that estimates of increased opportunities cannot be made prior to the merger, but there is no reason to believe that these estimates of past history will prove to be true in the future markets. For example, with market hubs and electronic trading, bilateral (decentralized) power markets are moving towards greater price discovery for all participants. As this evolution of the power marketing industry goes forward, it will be impossible to separate out what opportunities in the off-system energy markets are attributable to UCU's greater aggressiveness.

Q. ARE THERE ANY OTHER POTENTIAL REASONS FOR INCREASED OFF-SYSTEM ENERGY MARKET OPPORTUNITIES IN THE POST-MERGER ENVIRONMENT?

A. Yes, one possible explanation is that when the two control areas for MPS and EDE become a single control area, the barriers of pancaked transmission rates will be reduced and the opportunities for the off-system energy market may be increased. With the availability of regional transmission service, the barrier of pancaked transmission rates should be significantly reduced, if not eliminated. However, the Merger Applicants have not quantified what portion, if any, of the increased off-system energy market opportunities are due to decreased barriers to entry in the transmission system.

Q. WHAT IS THE MERGER APPLICANTS' PROPOSAL FOR THE MERGED ENTITY TO HAVE A SINGLE CONTROL AREA?

A. As a condition for the joint dispatch of the MPS and EDE power resources, the two systems must either be interconnected through regional network transmission service or directly connected by transmission lines built by the Merger Applicants. According to the direct testimony of Merger Applicants' witness Richard C. Kreul, one of the proposals for the interconnection of the MPS and EDE systems is to use the network service provisions of a Regional Transmission Organization (RTO) that includes both control areas in its region. Absent this possibility, a transmission line will be constructed to directly connect MPS and EDE. In his direct testimony, Mr. Kruel states that the Merger Applicant's currently favor a plan for "constructing a 161 kV line from south of the existing MPS Nevada Substation to the Empire Asbury power plant" at an estimated cost of $14.84 million (page 11 of Kreul direct testimony and page 4 of Schedule RCK-10).

In addition, the Merger Applicants propose to operate the MPS and EDE divisions as a single control area, which will require additional investments of $1 million, as described at page 10 of Mr. Kreul's direct testimony. This investment of approximately $15.84 million in transmission will be somewhat offset by lower human resource costs from going to a single control area operator. Subsequent to the Merger Applicants' filing, UCU has submitted a request for network service from SPP. Depending on the administrative fee for this service and any upgrades required by the SPP to provide this service, network service could be a less expensive way of integrating the two systems into a single control area. Subsequent to its filing, the SPP advised UCU what upgrades would be necessary to provide network service, and UCU has run comparisons that indicate that, for the next 10-year period, network service from SPP would be more expensive than other alternatives for combining control areas.

Q. WHAT IS YOUR INTERPRETATION OF THE PROJECTED $15.84 MILLION INVESTMENT IN TRANSMISSION?

A. In order to justify this investment, the Merger Applicants need to show the direct relationship between increased off-system energy market opportunities and the costs incurred for interconnecting the MPS and EDE systems. Instead of doing so, the Merger Applicants have assumed that by interconnecting the MPS and EDE systems, their off-system energy market opportunities will increase, resulting in "savings" of over $164 million for the next ten years. On an *ex post* basis, one way to measure the actual impact on "savings" from interconnecting the two systems is to calculate the incremental profits that result directly from the elimination of pancaked transmission rates. Also, incremental profits could be calculated for any reductions in transmission congestion coming from the additional investment in transmission or the integration of the two systems through network service. Then, as an *ex post* measure of savings, these incremental profits could be compared to whatever transmission costs are incurred to interconnect the two systems.

Q. WHAT OTHER FORMS OF SAVINGS FROM JOINTLY DISPATCHING THE TWO SYSTEMS CAN POTENTIALLY BE MEASURED ON AN *EX POST* BASIS?

A. Clearly, any improvements in the heat rate at the Asbury plant can be measured by using the pre-merger heat rate for the Asbury plant in the stand-alone dispatch for EDE that is performed as a part of the Electric Allocations Agreement.

Decreased cost of natural gas for EDE is more problematic. To perform this analysis, when the stand-alone dispatch is performed as a part of the Electric Allocations Agreement, the price of natural gas for EDE would need to be adjusted to what it would have been absent the merger. There may not be any good way of making this estimate.

Finally, there may be additional energy savings from having a different capacity mix for the merged system when compared to the stand-alone systems. In order to calculate this on an *ex post* basis, when the stand-alone dispatches are performed, the capacity mix for the stand-alone dispatches would need to be specified for capacity additions that would have been implemented absent the merger. Estimates of the capacity additions for stand-alone utilities would be based on current capacity expansion plans. However, our recent experience with electric resource plans shows that these plans are subject to continual change. The longer the time after the completion of the merger, the less accurately will these old resource plans represent what would have been done on a stand-alone basis for MPS and EDE.

Q. HAVE YOU ATTEMPTED TO QUANTIFY ANY OF THESE MERGER-RELATED SAVINGS?

A. Yes. I asked Mr. Lin to run stand-alone dispatches for MPS and EDE over the same ten-year period used in the Merger Applicants' calculation of merger savings. However, in these additional stand-alone dispatch runs, I asked Mr. Lin to make the off-system sales opportunities identical to those used for the joint dispatch runs. When Mr. Lin compared the results of the stand-alone dispatch runs to the joint-dispatch runs, he found that the $164 million "savings" had been reduced to only $6.95 million. This is the level of what I would call true merger savings related to potential upgrades in heat rates, savings in natural gas costs and changes in capacity mix.

Q. ARE YOU TESTIFYING THAT THE MERGER APPLICANTS HAVE NOT PROVIDED SUFFICIENT PROOF OF THE $164 MILLION IN CLAIMED MERGER-RELATED ENERGY SAVINGS FROM JOINT DISPATCH?

A. Yes. It is the Staff's position that only $6.95 million of the $164 million in energy cost savings can be directly related to the merger. The Merger Applicants have failed to include any testimony in their direct filing that would provide evidence that the increased sales opportunities estimated for the merged company are reasonably likely to occur. Even if their estimates of increased sales opportunities are reasonable, the Merger Applicants have failed to include any testimony in their direct filing that would provide evidence that such increased sales opportunities would not be available for the stand-alone companies. The Commission should expect that the surrebuttal testimony will include testimony that the Merger Applicants believe supports their position. If this occurs, the Staff should be given the opportunity to respond to such testimony.

Q. DOES THE ELECTRIC ALLOCATIONS AGREEMENT PROPOSED BY THE MERGER APPLICANTS INCLUDE ANY SPECIFICATION OF THE TYPES OF CHANGES IN INPUTS TO THE STAND-ALONE DISPATCH THAT ARE REQUIRED TO CALCULATE ENERGY COST SAVINGS FROM THE MERGER ON AN *EX POST* BASIS?

A. Unfortunately, the Electric Allocations Agreement does not contain any specific language for the changes that are required to calculate these savings on an *ex post* basis. As discussed above in my rebuttal testimony, the only indication that the Electric Allocations Agreement intends to incorporate changes brought about by the merger is the vague statement that the "own-load re-dispatch will reflect applicable pre-merger operating practices and conditions." If this type of vague language is allowed in the Electric Allocations Agreement, there will be significant arguments about what this phrase means in future rate cases. In addition, the wording of this language implicitly assumes that pre-merger operating practices and conditions are relevant for MPS and EDE as stand-alone utilities into the future. The Merger Applicants have provided no testimony in their direct filing regarding evidence to support this assumption.

Q. WHAT DO YOU RECOMMEND TO CORRECT THE FLAWS IN THE ELECTRIC ALLOCATIONS AGREEMENT?

A. I have attached as Schedule 4.1 and 4.2 to my rebuttal testimony my suggested revisions to the Electric Allocations Agreement proposed by the Merger Applicants. For purposes of comparison, in the attached Schedule 4.1, a strike-through is used for words that are to be removed and shading is used for words that are to be added. In the attached Schedule 4.2, the revised Electric Allocations Agreement appears in the edited form.

Q. WHAT CHANGES ARE YOU RECOMMENDING WITH RESPECT TO ALLOCATION OF WHAT HAS BEEN CHARACTERIZED BY THE MERGER APPLICANTS AS ENERGY COST SAVINGS?

A. As a part of their proposed regulatory plan, the Merger Applicants recommend that all of the savings in energy costs be allocated to EDE. I am recommending that since the Electric Allocations Agreement presumably would be in effect until the "effective time of retail competition in Missouri," that the allocations set out in that agreement **not** reflect a specific sharing proposal for a regulatory plan. Instead, the Electric Allocations Agreement should reflect an equitable sharing of the energy costs from the joint dispatch of the power supply resource of the two previously separated systems. In this regard, I recommend that energy costs be allocated between MPS and EDE in proportion to the stand-alone costs calculated for each system in that same month. These stand-alone calculations for MPS and EDE should use the same generating unit and interchange parameters, as developed in the joint dispatch model, including the same availability for off-system energy sales as used to calibrate the joint dispatch model to actual energy costs for each month. The following sentence in the Merger Applicants' proposed Electric Allocations Agreement should be stricken: "In addition, own load re-dispatch will reflect pre-merger operating practices and conditions."

Q. WHAT WOULD BE THE RESULTING ESTIMATED PERCENT ALLOCATIONS OF ENERGY COSTS BETWEEN MPS AND EDE?

A. I have calculated the estimated percent allocations for MPS and EDE for two cases. First, for purposes of rebuttal to the Merger Applicants' regulatory plan, I have calculated the stand-alone energy costs using the Merger Applicants' assumption of limited off-system sales opportunities, resulting in $164 million less in energy costs from the joint dispatch compared to the stand-alone dispatches. It should be emphasized that these are not the allocations that the Merger Applicants' are proposing in their regulatory plan, where all of the purported energy savings are allocated to EDE.

Second, for purposes of illustrating estimates based on the Staff's recommended Electric Allocations Agreement I have calculated the stand-alone energy costs for MPS and EDE on the assumption that the stand-alone entities will have the same off-system sales opportunities as the merged entity. This calculation assumes that the joint dispatch will result in $6.95 million less in energy costs than the stand-alone dispatches.

Q. WHAT ARE THE RESULTING ALLOCATION PERCENTAGES FOR MPS AND EDE FOR EACH OF THESE TWO CASES?

A. For the case of $164 million in purported energy cost savings, the allocation of energy costs and therefore energy cost-related savings is 52.5% for MPS (energy cost savings of $86.9 million) and 47.5% for EDE (energy cost savings of $77.9 million).

For the case of $6.95 million in energy savings, allocation of energy cost and therefore energy cost-related savings is 52.8% for MPS (energy cost savings of $3.67 million) and 47.2% for EDE (energy cost savings of $3.28 million).

B. REGULATORY PLAN FOR POWER SUPPLY COSTS

Q. WHAT IS MEANT BY THE TERM "REGULATORY PLAN" AS THAT TERM IS APPLIED TO POWER SUPPLY COSTS?

A. In the context of this merger, the "regulatory plan" as that term is applied to power supply cost is a special treatment of those costs that will allow the merged entity to retain some portion of the "savings" estimated as resulting from the merger over a specified time period. The framework for the regulatory plan is how power supply costs will be treated for each of the two divisions. Specifically, in the case of MPS, since there will likely be at least one, if not two, rate cases filed by MPS with this Commission within the next five years, the regulatory plan should specify how to treat generation costs in the context of these potential MPS rate cases. On the other hand, the regulatory plan also includes a rate freeze at EDE, in which case the regulatory plan really does not need to say anything about the treatment of generation costs for EDE.

Q. SHOULD THE BASIC ELECTRIC ALLOCATIONS AGREEMENT INCLUDE CALCULATIONS AND ALLOCATIONS OF POWER SUPPLY COSTS FOR A PROPOSED REGULATORY PLAN?

A. No. Because these special calculations and allocations for the regulatory plan are temporary, it is my opinion that they should not be included in the basic Electric Allocations Agreement. Instead, they should be an appendix or attachment to the basic Electric Allocations Agreement that would be in effect for a limited period of time.

Q. WHAT SHOULD BE THE OBJECTIVE IN THE ALLOCATION OF POWER SUPPLY COSTS FOR THE PURPOSE OF A REGULATORY PLAN?

A. The objective in the allocation of power supply costs should be to give the merged entity an opportunity to retain some portion of both the capacity cost savings and energy cost-related opportunities brought about by the merger. I purposefully used the words "energy cost-related opportunities," rather than the words "energy cost-related savings," because the measuring of "energy cost-related savings" on an *ex post* basis is impossible.

B.1 ALLOCATION OF ENERGY COST-RELATED OPPORTUNITIES

Q. WHAT DOES MR. HOLZWARTH PROPOSE FOR ALLOCATING THE ENERGY COST-RELATED OPPORTUNITIES?

A. Mr. Holzwarth proposes to allocate all of the energy cost-related opportunities to EDE based on the argument that "none of the savings would be possible absent the merger."

Q. DO YOU AGREE WITH MR. HOLZWARTH'S REASONING FOR ALLOCATING THE ENERGY COST-RELATED OPPORTUNITIES TO EDE?

A. No. First, only a very small fraction ($6.95 million of $164 million) of what Mr. Holzwarth is calling "savings" are true merger savings. Therefore, the premise of Mr. Holzwarth's statement is not valid. Second, even if his premise were valid, since the same argument could be made for MPS, it does not provide a rationale for an equitable allocation of these energy cost-related opportunities.

The true rationale for the allocation of one hundred percent of these energy cost-related opportunities to EDE is that it is a part of the regulatory plan sponsored by UCU witness John W. McKinney. Under that plan all of the energy cost-related opportunities are allocated to EDE, which is under a rate freeze for the first five years of a ten-year plan designed to allow the Merger Applicants to recover enough merger savings to cover at least 50% of the acquisition premium. In addition, over the second five years after the merger, the regulatory plan calls for all energy cost-related opportunities to continue to be assigned to EDE. During this same ten-year period, rate cases can be filed for MPS. In those rate cases, the energy costs for MPS would be based on a stand-alone dispatch for the MPS system with ratepayers receiving no benefits from the energy cost-related opportunities. This requirement for MPS follows from allocating all of the energy cost-related opportunities to EDE. Thus, under the regulatory plan proposed by the Merger Applicants, MPS ratepayers would not share in any energy cost-related opportunities from the merger for a ten-year period from the consummation of the merger.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING ANY PLAN TO SHARE ENERGY COST-RELATED OPPORTUNITIES?

A. First, the Commission should reject the Merger Applicants' proposed regulatory plan. Second, if the Commission decides that some type of regulatory plan should be included as a condition for the approval of this merger, I recommend that the Commission set out the policy guidelines for that regulatory plan in its order. These guidelines need only include a specification of the parameters discussed previously in my rebuttal testimony – sharing percentage, length of time and type of plan.

Q. IF THE COMMISSION WOULD MAKE SUCH A DETERMINATION, CAN YOU GIVE A SPECIFIC ILLUSTRATION OF THE POLICY GUIDELINES FOR THE REGULATORY PLAN RELATED TO ENERGY COST-RELATED OPPORTUNITIES?

A. An example of a policy guideline for the regulatory plan related to energy cost-related opportunities is: *profits from increased off-system energy sales opportunities are to be shared between ratepayers and shareholders on a 50-50 basis over the first 5 years following the consummation of the merger.*

Q. WHAT CALCULATIONS ARE NECESSARY TO IMPLEMENT THIS POLICY GUIDELINE?

A. For purposes of rate or complaint cases for either MPS or EDE over this sharing period, generation costs would be determined by running a stand-alone dispatch of supply sources for the utility, including purchased power, but excluding any sales opportunities. The power supply costs from these runs would be decreased by the appropriate allocation of profits from off-system sales from the joint dispatch for the combined resources of both the MPS and EDE divisions.

Q. WHAT IS THE APPROPRIATE ALLOCATION OF PROFITS FROM OFF-SYSTEM SALES FOR MPS?

A. Recall that the Merger Applicants' assumption about limited sales opportunities included $175 million of $295 million in total profits over the ten-year period. Over the first five years, this translates to $64.2 million of $111.3 million total profits, leaving $47.1 million in profits from increased opportunities to be divided equally between the customers and shareholders over that same five-year period. This can be accomplished by allocating 70.6% of the profits from sales to MPS, 8.3% of profits from sales to EDE, leaving 21.1% (= 100% -(70.6%+8.3%)) of total profits going to shareholders. Notice that 21.1% of the $111.3 million is $23.5 million, or one half of the $47.1 million in profits from increased off-system energy sales opportunities. The percentages recommended for allocation to MPS and EDE are based on factoring up profits from current sales levels on an equal percentage basis. The sum of these additional profits over stand-alone sales levels also equals $23.5 million, or one-half of the $47.1 million in profits from increased off-system energy sales opportunities.

Q. ARE PROFITS FROM EXPANDED OFF-SYSTEM ENERGY SALES OPPORTUNITIES THE ONLY SOURCE OF ENERGY COST-RELATED OPPORTUNITIES THAT MIGHT BE INCLUDED IN A POLICY OF ALLOCATING ENERGY COST-RELATED OPPORTUNITES EQUALLY BETWEEN RATEPAYERS AND SHAREHOLDERS?

A. No. In addition, the synergies from joint dispatch also represent energy cost-related opportunities and could be divided equally between ratepayers and shareholders over the initial 5-year period after the merger. The estimate of these savings for the first five years is an additional $39.7 million.

Q. HOW WOULD YOU CALCULATE THE JOINT DISPATCH SYNERGIES ON AN *EX POST* BASIS?

A. These synergies can easily be calculated as the difference between the sum of power supply costs for the stand-alone dispatches and the joint dispatch, excluding off-system sales. The 50% of these synergies going to ratepayers can then be allocated between MPS and EDE based on each division's percentage of stand-alone dispatch costs, excluding off-system sales.

Q. WHAT ARE THE ESTIMATED LEVELS FOR THESE ENERGY COST-RELATED OPPORTUNITIES GOING BETWEEN SHAREHOLDERS AND RATEPAYERS?

A. The calculations for the first five years of the merger are shown on Schedule 5 attached to my rebuttal testimony. Profits from sales going to MPS and EDE combine to 78.9% with shareholders being allocated the remaining 21.1%. Recall that 21.1% is one half of the increment in profits from expanded off-system sale opportunities.

Joint dispatch synergies are allocated on a 50-50 basis between ratepayers and shareholders, with MPS receiving just under 27.9% and EDE receiving just over 22.1%. With "perfect regulation" or under a plan for flowing savings back to ratepayers, both shareholders and ratepayers could expect to receive approximately $33.1 million over the five-year period.

Q. ASSUMING THAT THE REGULATORY PLAN ONLY APPLIES TO RATE OR COMPLAINT CASES, HOW MUCH INCREASED OPPORTUNITIES WILL SHAREHOLDERS ACTUALLY RETAIN?

A. If the regulatory plan does not include a refund mechanism, but depends totally on the filing of rate or complaint cases, the shareholders will actually retain more than 50% of the increased opportunities. Assume that during the five-year period, only one rate case is filed by UCU for both EDE and MPS for the year 2001 and no subsequent rate or complaint cases are filed during this period. Then the difference between the allocations from the remaining years and those for 2001 would actually go to shareholders. This difference is approximately $60 million in additional earnings going to shareholders. However, it appears that MPS may also have to file for an additional rate increase in 2002. Then the difference between the MPS allocations from the remaining three years and those for 2002 would go to shareholders instead. This would reduce the earnings going to shareholder to slightly more than $21 million in additional earnings.

Q. WHAT IS REQUIRED TO IMPLEMENT THIS REGULATORY PLAN?

A. I have attached an example of what is required to implement this regulatory plan for power supply costs as Schedule 6 to my rebuttal testimony. As stated previously, this schedule should not be included in the basic Electric Allocations Agreement, but instead be an attachment to that agreement.

Q. WHAT ARE THE ADVANTAGES OF THIS REGULATORY PLAN FOR SHARING ENERGY COST-RELATED OPPORTUNITIES?

A. First, the 50-50 sharing mechanism allows UCU an equal opportunity to share in the increased energy cost-related opportunities following the merger. Second, because of the profits from off-system sales going to shareholders, it gives UCU an incentive to maximize its opportunities for sales in the off-system energy market. Third, because additional sharing for shareholders occurs if UCU does not file for rate increases for the MPS division, it provides an incentive for UCU to minimize its overall costs and put off filing for subsequent rate increases during the sharing period. Fourth, the calculations necessary to implement this regulatory plan are very straightforward. Fifth, given the specificity of the allocations in the regulatory plan, UCU is protected from the Staff filing a complaint case that attempts to recover what the plan allocates to shareholders.

Q. HOW DOES THIS COMPARE TO THE REGULATORY PLAN PROPOSED BY THE MERGER APPLICANTS?

A. As indicated earlier in my testimony, the regulatory plan proposed by the Merger Applicants does not allocate any of the energy cost-related opportunities to MPS ratepayers over a ten-year period. In addition, EDE ratepayers are only allocated slightly less than $3.0 million per year in total merger benefits over the second five-year period after the completion of the merger. This regulatory plan is targeted to recover 50% of the acquisition premium over a ten-year period, and, as I will discuss in the next section of my testimony, allocates a significant portion of the energy cost-related opportunities from the UCU-EDE merger to pay off the acquisition premium related to the UCU-SJLP merger.

Q. ARE YOU RECOMMENDING THE REGULATORY SHARING PLAN FOR ENERGY COST-RELATED OPPORTUNITIES THAT IS SHOWN IN SCHEDULE 6?

A. I am not recommending a regulatory sharing plan for energy cost-related opportunities. My primary reservation about supporting a regulatory sharing plan for energy cost-related opportunities in the context of this merger case is that only $6.95 million of the $164 million of these energy cost-related opportunities are true merger savings. If the Commission adopts a regulatory sharing plan that includes the Merger Applicants' estimate, it should be for reasons other than sharing in true merger savings.

B.2 ALLOCATIONS OF CAPACITY COST SAVINGS

Q. DOES SCHEDULE 6 INCLUDE ANY SHARING OF THE CAPACITY COST SAVINGS?

A. I have not included any sharing of savings in generation capacity costs in Schedule 6. If the Commission adopts policy guidelines that include a 50-50 sharing of savings in capacity cost, I would recommend that the merged utility would have to document those savings at the time it files a rate case. Since the difference in capacity costs over the first four years of the merger is based on a difference of 10 megawatts of short-term capacity purchase, and in the first three years the merged utility will not be making any short-term capacity purchases, it will be difficult to document the level of *ex post* savings in capacity costs. The merged utility will need to gather reliable information on capacity sales in order to determine the cost savings. In my opinion, the megawatt levels ascribed to merger savings in capacity costs are small enough that they are fairly insignificant over the first ten years of the merger, where they average 9 megawatts per year.

Q. HAVE YOU REVIEWED THE MERGER APPLICANTS' PROPOSAL FOR ALLOCATING CAPACITY COST SAVINGS?

A. Yes, I have. At page 19 of Mr. Holzwarth's direct testimony, he shows the \$12.872 million in capacity savings as being allocated equally between MPS and EDE. There is no testimony in support of the rationale for this allocation.

Q. DO YOU AGREE WITH A 50% ALLOCATION OF CAPACITY COST SAVINGS BETWEEN MPS AND EDE?

A. No. This allocation is not consistent with the proposed electric allocations agreement that would allocate new capacity between MPS and EDE based on the capacity needs (equalized capacity reserves) of the two divisions. I have calculated the allocation of new capacity over the 10-year period from 2001 to 2010 to determine that 82.8% of capacity additions over that time period are required to meet MPS's load. Thus, I would recommend that 82.8% of the capacity cost savings be allocated to MPS and the remaining 17.2% be allocated to EDE.

B.3 ALLOCATION OF INCREASED TRANSMISSION COST

Q. HOW SHOULD THE NET INCREASE IN TRANMISSION COSTS FROM THE MERGER BE TREATED IN THE REGULATORY PLAN?

A. As indicated earlier in my testimony, the alternatives for transmission to integrate the two systems into a single control area are not yet determined. I would simply include these additional transmission costs as part of the merged utility's cost of service. The method for allocating this increase in costs between the two divisions would depend on how these additional costs were incurred. For example, if the additional transmission costs are the SPP administrative charges for network service, then these costs would be allocated based on each division's share of megawatt hours.

C. EFFECTS OF THE EDE MERGER

Q. WHAT EFFECT WILL THE PROPOSED UCU MERGER WITH SJLP HAVE ON THE ELECTRIC ALLOCATIONS AGREEMENT?

A. As a third division involved in the joint dispatch, SJLP would need to be added to the Electric Allocations Agreement.

Q. WHAT EFFECT DOES ADDING SJLP IN THE JOINT DISPATCH HAVE ON THE ESTIMATE OF INCREASED OPPORTUNITIES WITH RESPECT TO ENERGY COSTS?

A. I asked Mr. Lin to make additional power supply cost runs that include SJLP. First, all of the cases run for UCU and EDE were also run for UCU and SJLP. In this way, the increased opportunities in energy costs could be calculated separately. Second, new joint dispatch cases were run, which included all three utilities. Based on these additional dispatch runs, the increased opportunities could be determined for each merger separately and then compared to the increased opportunities from the three-way merger.

The results of these comparisons are shown on Schedule 7.1 attached to my testimony. What Schedule 7.1 shows is that in the first five years there is only $1.7 million difference in energy cost-related opportunities ("savings") between the two separate mergers and the three-way merger. This difference increases to $17 million when the last five years are added.

If the Merger Applicants' purported savings of $246 million is accepted, the estimates of stand-alone allocations of energy costs and energy cost-related savings among the three divisions is 46.6% to MPS ($114.8 million in savings), 42.2% to EDE ($103.8 million in savings) and 11.2% to SJLP ($27.5 million in savings).

Q. IF ONLY TRUE MERGER-RELATED SAVINGS IN ENERGY COST ARE INCLUDED, WHAT IS THE ESTIMATE OF SAVINGS FOR THE UCU-SJLP-EDE MERGER?

A. Mr. Lin made stand-alone dispatch runs for all three utilities assuming the same opportunities were available to each utility in the off-system sales market as were assumed to be available for the merged entity. The results were savings of $12.1 million over the same ten-year period. If the merger savings are only $12.1 million, the estimate of stand-alone allocations of energy costs and energy cost-related savings are 43.1% MPS ($5.2 million in savings), 48.2% EDE ($5.8 million in savings) and 8.7% SJLP ($1.1 million in savings).

Q. WHAT IS THE PROPER ALLOCATION OF THE ENERGY COST-RELATED OPPORTUNITIES BETWEEN THE TWO MERGERS?

A. The proper allocation of the energy cost-related opportunities between the two mergers is in proportion to the energy cost-related opportunities from the separate mergers. With somewhat lower energy cost-related opportunities from the UCU-SJLP-EDE merger, allocation in proportion to the benefits from the separate (stand-alone) mergers prevents any cross subsidies going from one merger to the other.

Q. IS THIS IN AGREEMENT WITH WHAT THE MERGER APPLICANTS FILED FOR ALLOCATIONS OF BENEFITS BETWEEN THE TWO MERGERS?

A. No, it is not. Schedule 7.2 compares the allocations proposed by the Merger Applicants to the allocations that would prevent cross subsidies. This comparison shows that over the first five-year period, the Merger Applicants' proposal would result in just under a $20 million subsidy going from the UCU-SJLP merger to the UCU-EDE merger, and that cross subsidy increases to almost $38 million over the ten-year period.

Q. WHAT EFFECT DID THE UCU MERGER WITH SJLP HAVE ON THE MERGER APPLICANTS' PROPOSED REGULATORY PLAN?

A. First, the Merger Applicants have not filed a proposed regulatory plan that reflects the energy cost-related opportunities from the UCU–EDE merger alone. All schedules and work papers related to the Merger Applicants' proposed regulatory plan assume a UCU-SJLP-EDE merger. Because the Merger Applicants have no regulatory plan for the UCU-EDE merger alone, and since this case only applies to that merger, the Commission should reject the Merger Applicants' proposed regulatory plan. If the

Commission allows the Merger Applicants to submit a proposed regulatory plan for UCU-EDE merger alone in its surrebuttal testimony, then the Commission should allow the Staff an opportunity to file additional testimony to that yet undetermined regulatory plan.

Second, the Merger Applicants' proposed UCU-SJLP-EDE regulatory plan for energy cost-related opportunities will result in MPS ratepayers not receiving any benefits and will also result in SJLP ratepayers subsidizing EDE ratepayers in order to pay off the acquisition premium offered by UCU to EDE shareholders. Thus, the Commission should reject the Merger Applicants' proposed regulatory plan.

Q. WHAT EFFECT WOULD THE PROPOSED MERGER WITH EDE HAVE ON THE REGULATORY PLAN FOR ENERGY COST-RELATED OPPORTUNITIES?

A. Over the first five years, the impact of the UCU-SJLP-EDE merger on the UCU-EDE merger is to reduce energy cost-related opportunities by less than 2%. There would therefore be little impact on the regulatory plan. In essence, there would still be a 50-50 sharing of additional profits and joint dispatch synergies between ratepayers and shareholders. Specific calculations for the UCU-SJLP-EDE merger require allocation factors for the three companies rather than the two. I have made these calculations, which are shown on Schedule 8 attached to my testimony.

Q. HAVE YOU LOOKED AT THE IMPACT OF THE THREE-WAY MERGER ON CAPACITY COST SAVINGS?

A. Yes. The Company workpapers calculate the capacity cost savings for the ten-year period starting in 2001. The capacity cost savings for the UCU-EDE merger are

$12.9 million, but for the UCU-EDE-SJLP merger, the capacity cost savings over this same period drop to $10.0 million. However, in both mergers there is a significant increase in merged capacity cost in year 10. For the UCU-EDE merger, the capacity savings over the first nine years are $15.1 million and for the UCU-EDE-SJLP merger, the capacity savings over the first nine years are $18.2 million. Thus, one should not conclude that the three-way merger results in lower levels of capacity savings.

Q. USING THE SAME ALLOCATION METHOD THAT WAS APPLIED TO THE CAPACITY SAVINGS IN THE UCU-EDE MERGER, WHAT WOULD THE ALLOCATION OF THE CAPACITY SAVINGS BE FOR THE UCU-EDE-SJLP MERGER?

A. Using the allocation of new capacity as the basis for allocating the capacity savings, MPS would be allocated 61.6%, EDE would be allocated 13.0% and SJLP would be allocated 17.4%.

III. MERGER-RELATED MARKET POWER

Q. HAVE YOU PERFORMED AN ANALYSIS OF HORIZONTAL MARKET POWER SPECIFICALLY FOR THE UCU-SJLP MERGER?

A. No, I have not. In my opinion, such an analysis is not critical for this merger. Specifically, based on the work that was done for the Staff in the Kansas City Power & Light Company – Western Resources Inc. merger, the proposed merger between UCU and EDE would result in the merged entity having less than 8.2% of the market share in the northern SPP region. The month-by-month calculation of market shares for the UCU-EDE merger is shown on Schedules 9.1 and 9.2 attached to my testimony.

I also reviewed the Merger Applicants' filing on market power at the Federal Energy Regulatory Commission, and while I do not agree with the use of destination markets for analyzing horizontal market power, this analysis did not indicate that the proposed merger would result in any significant problems with market concentration with respect to the merged entity. Based on these two reviews, there appears to be little incremental value in performing additional horizontal market power studies on market concentration for this proposed merger.

Q. DOES THIS MEAN THAT THERE ARE NO HORIZONTAL MARKET POWER PROBLEMS IN THE MPS AND EDE SERVICE TERRITORIES?

A. No. Horizontal market power can exist in each of these service territories in the form of what are called load pockets. These load pockets are geographic areas within the service territories where the transmission system will not allow competitive generation to provide services to a significant percentage of end-use customer loads on a year-around basis. Currently, such load pockets do not pose a problem because the loads within the service territories are served by the incumbent utilities on a regulated basis. However, if the state of Missouri implements retail competition at a future date, then significant horizontal market power may exist for the incumbent utility within these load pockets.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO POTENTIAL HORIZONTAL MARKET POWER RELATED TO LOAD POCKETS?

A. I recommend, as a condition for the approval of this merger, that the Merger Applicants agree to submit a study showing what percentage of load can be served from competitive generation sources throughout their merged service territory.

Q. WHAT IS VERTICAL MARKET POWER AND WHY IS IT RELEVANT TO THIS PROPOSED MERGER?

A. Vertical market power is the ability of a supplier to restrict the access for competitors to any markets that are crucial in the supply chain. In competitive electricity supply the most crucial restriction that a supplier can impose is on the use of the transmission system. In Order No. 888 and Order No. 889, the FERC recognized this impediment to competition in the wholesale electricity markets and ordered all utilities subject to its jurisdiction to unbundle their transmission rates and offer transmission service on a non-discriminatory basis. Even under this open access to transmission, as long as this service is being offered on a utility-by-utility basis, the utility could restrict the amount of service it offers to favor its own generation, and with pancaked transmission rates, incumbent utilities would maintain an unfair competitive advantage. Subsequent to Order No. 888 and Order 889, the FERC recently issued Order No. 2000 in which FERC jurisdictional utilities are required to either join a Regional Transmission Organization (RTO) or explain what efforts and obstacles have prevented the FERC jurisdictional utility from doing so. The effect of joining the RTO is twofold:

1) The determination of available transmission capability will be made by an organization that is independent of the utility; and

2) The RTO will have a regional transmission rate that will eliminate the competitive advantage of the incumbent utility from rate pancaking.

Q. IS IT IMPORTANT THAT THE MERGED UTILITY, UCU-EDE, JOIN AN RTO?

A. Yes, it is important in order to eliminate any ability by the merged utility to manipulate the availability of transmission capability on its system. It is also important in order to eliminate pancaked transmission rates. The elimination of pancaked transmission rates will increase both the competitiveness and the energy cost efficiency in the wholesale electricity market. It is unlikely that the merger will be completed by the October 15, 2000 deadline that the FERC has set for utilities that are not already participating in a regional transmission entity in conformance with the eleven Independent System Operator (ISO) principles enumerated in Order No. 888, to file an explanation of their efforts to join an RTO and what obstacles have prevented the utility from doing so. This deadline is extended to January 15, 2001 for jurisdictional utilities that have joined a regional transmission entity in conformance with the eleven ISO principles enumerated in Order No. 888. Thus, the timing of the merger utility joining an RTO is complicated by the FERC filing dates.

Q. WHAT DO YOU PROPOSE TO RESOLVE THIS COMPLICATION?

A. As a condition of approval for this merger, the separate utilities should be required to make a commitment to join the <u>same</u> regional transmission entity that meets the eleven ISO principles enumerated in Order No. 888 before the October 15, 2000 deadline of Order No. 2000. At this point in time it appears that UCU and EDE could join either the SPP or the Midwest ISO (MISO). The MISO has received FERC approval as having met the eleven ISO principles of Order No. 888, but has not yet submitted a proposal to be approved as an RTO. Because the FERC's Order on the SPP filing occurred subsequent to Order No. 2000, the FERC did not make a determination of whether or not the SPP filing met the eleven ISO Principles. Instead, the FERC evaluated the SPP proposal using the RTO standards set out in Order No. 2000. While the SPP's proposal to be approved as an RTO has been rejected by the FERC, the FERC has encouraged the SPP to revise its proposal and has given specific guidance regarding what changes need to be made.

Q. DO YOU HAVE A RECOMMENDATION AS TO WHICH OF THESE TWO REGIONAL ENTITIES THE MERGED UTILITY SHOULD JOIN?

A. No, I do not. The MISO has the advantage of having already been approved by the FERC as an ISO, but not as an RTO. However, the SPP has the advantage of already providing regional transmission service and providing that service at a relatively low cost. In addition, these regional entities are in the process of discussing a possible merger, a possible umbrella relationship or a possible functional elimination of seams between the two. Any of these solutions would lead to making a decision as to which RTO to join based on the cost to the merged utility. Whether those solutions can be worked out before the October 15, 2000 deadline is not known at this time.

As indicated earlier in my testimony, UCU has requested network service from the SPP. That service would be available upon completion of the merger and the merged utility would be able to begin joint dispatch almost immediately. The MISO will not be providing service until the summer of 2001, and even then, it may not have the systems in place to provide network service to a new member. Thus, if the objective is to begin benefiting from the energy cost-related opportunities from the merger at the earliest possible date, joining the SPP RTO appears to be the better choice.

Q. DOES THE ADDITION OF SJLP TO THE MERGER HAVE ANY IMPACT ON EITHER HORIZONTAL MARKET POWER OR THE CHOICE OF REGIONAL TRANSMISSION ENTITY?

A. As shown on Schedules 10.1 and 10.2 attached to my testimony, the addition of SJLP to the merger increases the merged entity's market share to a range of 4.1% to 9.0%, with an average of 6.7%. These levels of concentration should not pose horizontal market power concerns in the northern SPP region. EDE is already a member of the SPP, and has signed the agency agreement to be a part of the regional tariff. UCU is also a member of the SPP, but has not yet signed the agency agreement to be a part of the regional tariff. SJLP is a member of the Mid-Continent Area Power Pool (MAPP), having left the SPP a few years ago. The MAPP and the MISO have agreed to merge their regional transmission service functions, excluding the regional reliability council functions of MAPP. While the UCU-EDE merger would appear to favor having both UCU and EDE join the SPP, adding SJLP to the merger poses some interesting questions.

With respect to electricity markets, SJLP is clearly linked into MAPP with its contract for power from the Nebraska Public Power District. EDE is clearly linked with the SPP region, having signed the SPP agency agreement. These two utilities tend to engage in generation transactions in different areas of the country. UCU's MPS current generation transactions tend to reflect both the SPP and the MAPP regions, as well as transactions east into what will be the MISO region.

Q. DO YOU SEE UCU JOINING ONE REGIONAL TRANSMISSION ENTITY AND EDE JOINING ANOTHER PRIOR TO THE OCTOBER 15, 2000 DEADLINE AS A VIABLE SHORT-TERM SOLUTION?

A. No. Because the merged utility will have a single control area for its generation and load, it must join the same regional transmission entity.

Q. IF THE MERGED UTILITY RECEIVES NETWORK TRANSMISSION SERVICE FROM A REGIONAL TRANSMISSION ENTITY, WHAT WILL BE THE COST TO MISSOURI RETAIL CUSTOMERS?

A. The cost from receiving network service will be the administrative fee of the regional transmission entity. While the merged utility must pay a transmission rate plus an administrative fee for network transmission service, for both the MISO and the SPP, the merged utility would receive back from the regional transmission entity a payment equal to the what it paid in cost for the transmission rate. However, as a condition for receiving network service, UCU may be required to make upgrades to the existing transmission system. If this is the case, then there would be additional costs to taking network service.

IV. SUMMARY

Q. HAVING TESTIFIED ON THREE ISSUES, DO YOU SEE ANY COMMON THREADS THAT DRAWS ALL THREE AREAS TOGETHER?

A. Yes. First, there is a connection between market power and the incremental energy cost-related opportunities that the Merger Applicants claim to be merger-related, energy cost savings. Second, there is a connection between the incremental energy cost-related opportunities and the acquisition premium.

Q. WHAT IS THE CONNECTION BETWEEN MARKET POWER AND THE INCREMENTAL ENERGY COST-RELATED OPPORTUNITIES IF THEY ARE TRULY MERGER-RELTATED?

A. In its market power studies (submitted to the FERC and provided to the Staff), the Merger Applicants assume that any capacity that is economic (at or below an assumed market price) can compete in a destination market except in the following two situations:

1) when transmission costs are added, the capacity becomes non-economic; or

2) transmission availability restricts access into the destination market.

Thus, the only explanation for the merged entity to have increased energy cost-related opportunities in the off-system sales market that is consistent with its market power study is either the elimination of transmission costs or the elimination of transmission constraints brought about by the merger. An alternative explanation is that the assumptions going into the market power studies are incorrect and because of the imperfections in the off-system energy markets, the merged entity is able to achieve the increase in energy cost-related opportunities through the exercise of market power. My market power analysis of the electricity markets indicates that the alternative explanation of the merged entity having significant market power is not plausible. Therefore, the only consistent explanation that the Commission should accept of the energy cost-related opportunities being merger-related is through the elimination of transmission costs or transmission constraints brought about by the merger. Since the Merger Applicants have no testimony or evidence to support this position, the Commission should reject the claim that the increase in energy cost-opportunities are merger-related.

Q. WHAT IS THE CONNECTION BETWEEN THE INCREASE IN ENERGY COST-RELATED OPPORTUNITIES AND THE ACQUISITION PREMIUM?

A. Shareholders cannot accurately factor into their value of UCU and EDE stock the potential earnings from the increase in energy cost-related opportunities until the Commission has made a determination regarding the regulatory treatment (sharing between ratepayers and shareholders) of these earnings. Thus, current stock prices would tend not to reflect higher earnings for either the separate or merged entities. In making its offer to EDE shareholders, UCU did factor in the higher earnings from these energy cost-related opportunities and this has put UCU in a position of requesting recovery of a portion of the acquisition premium that is to be paid to EDE shareholders.

As pointed out previously, the Merger Applicant proposes the incorrect causal chain for the acquisition premium in an attempt to dictate what the Commission policy should be regarding a regulatory sharing plan. The Staff recommendation to reject the Merger Applicants' regulatory plan does not mean that the merged entity will not benefit from the increase in energy cost-related opportunities. At a minimum, under continued regulation of retail rates the merged entity will benefit through regulatory lag. At the other extreme, if Missouri moves to retail competition and generation is split off as a separate, deregulated entity, then the separate generation company will receive all the benefits of increased energy cost-related opportunities.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Joint Application of UtiliCorp United Inc. and The Empire District Electric Company for Authority to Merge The Empire District Electric Company with and into UtiliCorp United Inc., and, in Connection Therewith, Certain Other Related Transactions.	)))))))	CASE NO. EM-2000-369

AFFIDAVIT OF MICHAEL S. PROCTOR

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael S. Proctor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing written testimony in question and answer form, consisting of 66 pages of testimony to be presented in the above case, that the answers in the attached written testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.

Michael S Proctor
Michael S. Proctor

Subscribed and sworn to before me this 15th day of June, 2000.

Joyce C. Neuner
Notary Public

My commission expires

Joyce C. Neuner
Notary Public, State of Missouri
~~County of Osage~~
My Commission Exp. 06/18/2001

CASE 1: Market Price Below Decremental Cost

Assumptions on Utility Costs and Market Price			
Utility A			
Incremental cost above meeting native load	=	$20/MWh for first 100	MWh
		$25/MWh for next 100	MWh
Decremental cost below meeting native load	=	$18/MWh for first 100	MWh
		$15/MWh for first 100	MWh
Utility B			
Incremental cost above meeting native load	=	$28/MWh for first 100	MWh
		$30/MWh for next 100	MWh
Decremental cost below meeting native load	=	$25/MWh for first 100	MWh
		$20/MWh for next 100	MWh
Market Price for Electricity			
Buy or Sell Electricity at a market price	=	$18/MWh	

Dispatches, Sales & Purchases

Stand Alone Dispatch		Joint Dispatch	
Utility A		**Utility A**	
1. Incremental costs are above market price and therefore cannot sell.		1. Incremental costs are above market price and therefore cannot sell.	
2. Decremental costs are at or below market price and therefore cannot buy.		2. Decremental costs are at or below market price and therefore cannot buy.	
3. Therefore, there is no change in generation and/or profits.		3. Therefore, there is no change in generation and/or profits.	
Utility B		**Utility B**	
Will replace $25 and $20 generation		Will replace $25 and $20 generation	
-100 MWh x $25 /MWh =	-$2,500	-100 MWh x $25 /MWh =	-$2,500
-100 MWh x $20 /MWh =	-$2,000	-100 MWh x $20 /MWh =	-$2,000
-200 MWh	-$4,500	-200 MWh	-$4,500
with $18 generation from the market		with $18 generation from the market	
200 MWh x $18 /MWh =	$3,600	200 MWh x $18 /MWh =	$3,600
at a net savings of	-$900	at a net savings of	-$900
Change in Cost	-$900	**Change in Cost**	-$900

Summary of Results

Stand Alone Dispatch		Joint Dispatch	
Inc (Dec) Generation - A	0	Inc (Dec) Generation - A	0
Inc (Dec) Generation - B	-200	Inc (Dec) Generation - B	-200
Total Incremental Generation	-200	**Total Incremental Generation**	-200
Costs of Purchases - A	$0	Costs of Purchases - A	$0
Costs of Purchases - B	$3,600	Costs of Purchases - B	$3,600
Net Revenues from Sales/Purch	$3,600	**Total Revenues from Sales**	$3,600
Inc (Dec) Generation Costs - A	$0	Inc (Dec) Generation Costs - A	$0
Inc (Dec) Generation Costs - B	-$4,500	Inc (Dec) Generation Costs - B	-$4,500
Total Incremental Gen Costs	-$4,500	**Total Incremental Gen Costs**	-$4,500
Savings from Purchases - A	$0	Savings from Purchases - A	$0
Savings from Purchases - B	$900	Savings from Purchases - B	$900
Total Savings from Purchases	$900	**Total Savings from Purchases**	$900

CASE 2: Market Price Between Dec & Inc Cost

Assumptions on Utility Costs and Market Price			
Utility A			
Incremental cost above meeting native load	=	$20/MWh for first 100	MWh
		$25/MWh for next 100	MWh
Decremental cost below meeting native load	=	$18/MWh for first 100	MWh
		$15/MWh for next 100	MWh
Utility B			
Incremental cost above meeting native load	=	$28/MWh for first 100	MWh
		$30/MWh for next 100	MWh
Decremental cost below meeting native load	=	$25/MWh for first 100	MWh
		$20/MWh for next 100	MWh
Market Price for Electricity			
Buy or Sell Electricity at a market price	=	$23/MWh	

Dispatches, Sales & Purchases	
Stand Alone Dispatch	**Joint Dispatch**
Utility A	**Utility A**
Will sell 100 MWh at an incremental cost of 100 MWh x $20 /MWh = **$2,000** and receive incremental revenues of: 100 MWh x $23 /MWh = **$2,300** resulting in a profit of: **$300**	Will replace $25 gen at Utility B with $20 generation at an incrmental cost of 100 MWh x $20 /MWh = **$2,000**
Utility B	**Utility B**
Will replace $25 generation at a decremental cost of: -100 MWh x $25 /MWh = **-$2,500** with purchased power at a cost of 100 MWh x $23 /MWh = **$2,300** at a net savings of **$200**	Will replace $25 gen with $20 gen from Utility A at a decremental cost of -100 MWh x $25 /MWh = **-$2,500**
Change in Cost **-$500**	**Change in Cost** **-$500**

Schedule 2.1

CASE 2: Market Price Between Dec & Inc Cost

Summary of Results			
Stand Alone Dispatch		**Joint Dispatch**	
Inc (Dec) Generation - A	100	Inc (Dec) Generation - A	100
Inc (Dec) Generation - B	-100	Inc (Dec) Generation - B	-100
Net Inc/Dec Generation	0	**Total Incremental Generation**	0
Revenues from Sales - A	$2,300	Revenues from Sales - A	$0
Costs of Purchases - B	-$2,300	Costs of Purchases - B	$0
Net Revenues from Sales/Purch	$0	**Total Revenues from Sales**	$0
Inc (Dec) Generation Costs - A	$2,000	Inc (Dec) Generation Costs - A	$2,000
Inc (Dec) Generation Costs - B	-$2,500	Inc (Dec) Generation Costs - B	-$2,500
Net Inc/Dec Gen Costs	-$500	**Net Inc/Dec Gen Costs**	-$500
Profits from Sales - A	$300	Profits from Sales - A	$0
Profits from Sales - B	$0	Profits from Sales - B	$0
Total Profits from Sales	$300	**Total Profits from Sales**	$0
Balance - A	$0	Balance - A	-$2,000
Balance - B	$200	Balance - B	$2,500
Total Balance*	$200	Total Balance	$500

* Balance = (Revenues from Sales - Inc (Dec) Generation Costs) - (Profits from Sales)

Joint Dispatch Allocation Rule							
Whenever one utility's generation is substituted for another, the utility receiving the generation will pay the utility supplying the generation its **opportunity cost = incremental generation cost + loss of profits**							
Utility A's opportunity cost for serving 100 MWh's of load on Utility B is the incremental:							
Cost of the generation	100 MWh	x	$20	/MWh	=	$2,000	
plus the loss of profits	100 MWh	x	$3	/MWh	=	$300	
equals opportunity cost.						$2,300	

Net Position of Each Utility After Allocation Rule			
Utility A		**Utility B**	
Incremental Cost	-$2,000	**Incremental Cost**	$2,500
Revenues from Sales	$0	**Revenues from Sales**	$0
Allocation Transfer	$2,300	**Allocation Transfer**	-$2,300
Total	$300	**Total**	$200

Stand Alone Position Before Joint Dispatch			
Utility A		**Utility B**	
Incremental Cost	-$2,000	**Incremental Cost**	$2,500
Revenues from Sales	$2,300	**Revenues from Sales**	-$2,300
Total	$300	**Total**	$200

Schedule 2.2

CASE 3: Market Price Above Incremental Cost

Assumptions on Utility Costs and Market Price		
Utility A		
Incremental cost above meeting native load	=	$20/MWh for first 100 MWh
		$25/MWh for next 100 MWh
		$28/MWh for first 100 MWh
		$30/MWh for next 100 MWh
Decremental cost below meeting native load	=	$18/MWh for first 100 MWh
		$15/MWh for first 100 MWh
Utility B		
Incremental cost above meeting native load	=	$28/MWh for first 100 MWh
		$30/MWh for next 100 MWh
Decremental cost below meeting native load	=	$25/MWh for first 100 MWh
		$20/MWh for next 100 MWh
Market Price for Electricity		
Buy or Sell Electricity at a market price	=	$30/MWh

Dispatches, Sales & Purchases			
Stand Alone Dispatch		**Joint Dispatch**	
Utility A		**Utility A**	
		Replaces $25 gen at Utility B with $20 generation at an incremental cost of	
		100 MWh x $20 /MWh =	**$2,000**
Sells 300 MWh at a cumulative incremental cost of		Sells 200 MWh at a cumulative incremental cost of	
100 MWh x $20 /MWh =	$2,000		
100 MWh x $25 /MWh =	$2,500	100 MWh x $25 /MWh =	$2,500
100 MWh x $28 /MWh =	$2,800	100 MWh x $28 /MWh =	$2,800
300 MWh	**$7,300**	200 MWh	**$5,300**
and receive incremental revenues of:		and receive incremental revenues of:	
300 MWh x $30 /MWh =	**$9,000**	200 MWh x $30 /MWh =	**$6,000**
resulting in a profit of	**$1,700**	resulting in a profit of	**$700**
Utility B		**Utility B**	
		Replace $25 gen with $20 gen from Utility A at a decremental cost of	
		-100 MWh x $25 /MWh =	**-$2,500**
		Sells 200 MWh at a cumulative incremental cost of	
Sells 100 MWh at a cumulative incremental cost of		100 MWh x $25 /MWh =	$2,500
		100 MWh x $28 /MWh =	$2,800
100 MWh x $28 /MWh =	**$2,800**	200 MWh	**$5,300**
and receives incremental revenues of:		and receives incremental revenues of:	
100 MWh x $30 /MWh =	**$3,000**	200 MWh x $30 /MWh =	**$6,000**
resulting in a profit of	**$200**	resulting in a profit of	**$700**
Change in Cost	**-$1,900**	**Change in Cost**	**-$1,900**

CASE 3: Market Price Above Incremental Cost

Summary of Results			
Stand Alone Dispatch		**Joint Dispatch**	
Net Inc (Dec) Generation - A	300	Net Inc (Dec) Generation - A	300
Net Inc (Dec) Generation - B	100	Net Inc (Dec) Generation - B	100
Total Net Inc (Dec) Generation	400	**Total Net Inc (Dec) Generation**	400
Revenues - Sales (Purch) - A	$9,000	Revenues from Sales - A	$6,000
Revenues - Sales (Purch) - B	$3,000	Revenues from Sales - B	$6,000
Total Revenues from Sales	$12,000	**Total Revenues from Sales**	$12,000
Net Inc (Dec) Gen Costs - A	$7,300	Net Inc (Dec) Gen Costs - A	$7,300
Net Inc (Dec) Gen Costs - B	$2,800	Net Inc (Dec) Gen Costs - B	$2,800
Total Net Inc (Dec) Gen Costs	$10,100	**Total Net Inc (Dec) Gen Costs**	$10,100
Profits from Sales - A	$1,700	Profits from Sales - A	$700
Profits from Sales - B	$200	Profits from Sales - B	$700
Total Profits from Sales	$1,900	**Total Profits from Sales**	$1,400
Balance - A	$0	Balance - A	-$2,000
Balance - B	$0	Balance - B	$2,500
Total Balance*	$0	Total Balance	$500

*Balance = (Revenues from Sales - Inc (Dec) Generation Costs) - (Profits from Sales)

Joint Dispatch Allocation Rule							
Whenever one utility's generation is substituted for another, the utility receiving the generation will pay the utility supplying the generation its **opportunity cost = incremental generation cost + loss of profits**							
Utility A's opportunity cost for serving 100 MWh's of load on Utility B is the incremental:							
Cost of the generation	100	MWh	x	$20	/MWh	=	$2,000
plus the loss of profits	100	MWh	x	$10	/MWh	=	$1,000
equals opportunity cost.							$3,000

Net Position of Each Utility After Allocation Rule			
Utility A		**Utility B**	
Incremental Cost	-$7,300	**Incremental Cost**	-$2,800
Revenues from Sales	$6,000	**Revenues from Sales**	$6,000
Allocation Transfer	$3,000	**Allocation Transfer**	-$3,000
Total	$1,700	**Total**	$200

Stand Alone Position Before Joint Dispatch			
Utility A		**Utility B**	
Incremental Cost	-$7,300	**Incremental Cost**	-$2,800
Revenues from Sales	$9,000	**Revenues from Sales**	$3,000
Total	$1,700	**Total**	$200

Schedule 3.2

EDE – MPS ELECTRIC ALLOCATIONS AGREEMENT

This Electric Allocations Agreement ~~(Allocations Agreement)~~ is in regard to ~~the~~ Missouri Public Service (MPS)~~, a division of UtiliCorp United Inc. (UCU)~~ and Empire District Electric Company (EDE), Divisions of UtiliCorp United Inc. (UCU).

ARTICLE I – TERM OF AGREEMENT

1.01 This EDE-MPS Electric Allocations Agreement shall become effective at the closing of the Merger, or such later date as may be fixed by any required regulatory acceptance.

1.02 This EDE – MPS Electric Allocations Agreement shall continue from year-to-year thereafter until terminated by the Effective Time of Retail Competition in Missouri.

ARTICLE II – DEFINITIONS

2.01 Generation Dispatch & Energy Trading shall be a center operated by UCU ~~for~~ solely devoted to the optimal utilization of system power resources for the supply of power and energy for ~~the Company~~ MPS and EDE.

2.02 Divisions shall be MPS and~~/or~~ EDE.

2.03 Economic Dispatch shall be the distribution of total power resource requirements among alternative sources for system economy with due consideration of system security.

ARTICLE III – PURPOSE

3.01 Purpose of This Agreement
The purpose of the EDE – MPS Electric Allocations Agreement is to provide the basis for the allocation of generation and purchased power resources and costs under the operation of UCU to achieve optimal economies consistent with reliable electric service and reasonable utilization of natural resources; and to establish the basis for capacity commitments within the Company.

ARTICLE IV – Allocations

4.01 Planning and Authorization of Generation Capacity
For planning purposes, UCU shall coordinate each Division's forecast of System Capacity to meet the overall System Capacity Responsibility and Capacity Margin.

4.02 Capacity Margin Requirements

Capacity Margin requirements for MPS and EDE shall be determined on a combined load basis and shall be in accordance with the Southwest Power Pool (SPP) and Mid-America Power Pool (MAPP) criteria for reserve planning. ~~Capacity Margin requirements for EDE shall be in accordance with the Mid-America Power Pool (MAPP).~~

4.03 Assignment of Existing Generation Capacity and Capacity Costs to Divisions

Each Division shall have assigned to it such generating capacity and associated costs as were owned or contracted for by it prior to the closing of the merger to supply its System Peak Responsibility.

4.04 Allocation of New Generation Capacity to Divisions

Prior to June 1 each year, new generation capacity owned or contracted for by UCU shall be allocated in such a way as to equalize on a pro-rata basis any capacity in excess of the respective reserve requirements of each Division. The capacity reserve margin is calculated by the following.

a. The capacity sum is the assigned existing capacity plus allocated new capacity;
b. The ratio is the ~~Division~~ capacity sum divided by the sum of the non-coincident peak demand of the Divisions; and
c. The capacity reserve margin is the ratio minus 1.

4.05 Allocation of New Generation Capacity Costs to Divisions

Unless otherwise specified, the cost of all new generation capacity owned or contracted for by MPS shall be allocated in such a way as to equalize the costs per kilowatt of new generation capacity between Divisions ~~across the Company~~. The exceptions are listed below.

a. If new generation capacity is built in such a way that facilities use existing generation or generation sites assigned to a Division under 4.03, then UCU shall obtain estimates of the cost savings from the shared facilities from at least three outside sources.
b. The cost savings attributable to shared facilities will be the average of the estimates obtained from outside sources.
c. The estimated cost savings will be credited as a decrease in allocated costs to the Division with the shared facilities, and will be debited as an increase in allocated costs to other Divisions.

4.06 Economic Dispatch

The UCU Dispatch Center shall perform Economic Dispatch by scheduling energy output of the generation resources to obtain the lowest cost of energy for serving System demand consistent with operating and security constraints, including voltage control, stability, loading of facilities, operating guides, interconnection contracts fuel commitments, environmental requirements and continuity of service to customers.

4.07 Exchange With Other Utilities
The UCU Dispatch Center shall coordinate and direct off-system purchases and sales of energy necessary to meet system requirements or to improve system economy for the Divisions.

4.08 Allocation of Energy Costs
In order to maximize the economic benefits available to UCU, UCU will dispatch the power supply resources of MPS and EDE in a centralized manner (~~centralized~~ joint dispatch). To accomplish this, energy costs for EDE and MPS resulting from centralized dispatch of the combined generating units and purchased power resources will be determined in the following manner:

a. Accounting information for energy costs incurred each month will be maintained separately for each Division.
   1. Energy costs from generation resources assigned to each division under 4.03 will be assigned to that same Division.
   2. Energy costs from generation resources allocated to each Division under 4.04 will be allocated to that same Division using the same allocation factor used for allocating new generation.
   3. Energy costs from other generation resources outside the combined centers system will be allocated to each Division on equal dollars per megawatt-hour basis.

b. The RealTime® production cost model will be used to simulate monthly fuel and interchange ~~energy costs~~ purchases and sales using data based on actual operating statistics for the subject month. Monthly operating statistics will include data for all power resources which were utilized plus historical and anticipated performance characteristics of power resources not utilized. Generating unit operating parameters used in the RealTime® model will be established using actual hourly generation values. These operating parameters will then be adjusted, if necessary, until RealTime® model output statistics for the joint dispatch reflect actual production and interchange purchases and sale data (i.e., fuel costs, heat rates, maintenance outages, etc.) for the subject month. The monthly costs (net of profits from interchange sales) resulting from the joint dispatch of the calibrated RealTime® model will be the first component used in the overall calculations of energy costs. ~~Once the model is calibrated to the actual generation parameters, it will be permitted to re-dispatch the generating resources along with actual interchange transactions that occurred during the month in order to meet the actual joint hourly load profile of the Company.~~

c. The MPS and EDE systems will then be modeled on ~~an "own load" redispatch~~ a stand-alone dispatch basis for the subject month. Generating unit and interchange parameters, as developed in the joint dispatch model (step b, above), will be used as input data for the stand-alone production cost simulations to be performed for each Company. ~~In addition, own load re-dispatch will reflect applicable pre-merger operating practices and conditions.~~

d. ~~Each Division's incremental or decremental energy cost for the month will be determined as the difference between actual (step a. above) and the modeled cost (step c. above). The sum of the incremental costs and the decremental costs shall represent the cost savings achieved through centralized dispatch.~~ The stand-alone costs (step c. above) of EDE and MPS will then each be ~~reduced~~ factored ~~by~~ on an equal percentage basis to equal the total costs determined from the joint dispatch (step b. above) ~~of the cost savings~~ . Subject to the conditions set out in the Regulatory Plan attachment to this Electric Allocations Agreement, the result will be the adjusted energy cost for the month for EDE and MPS.

e. The Divisions shall reconcile energy costs each month. The Division(s) which incurred additional costs during the month for the benefit of the other Division(s) shall receive from the benefiting Division(s) a credit equal to the difference between the costs incurred for the month (step a. above) and the adjusted energy cost (step d. above).

ARTICLE V – CENTRAL DISPATCH CENTER

5.01 Central Power Dispatch Center
UCU shall provide and operate a Central Power Dispatch Center (CPDC) adequately equipped and staffed to meet the requirements for efficient, economical and reliable operation as contemplated by this Electric Allocations Agreement.

5.02 Communications and Other Facilities
The CDPC shall provide communications and other facilities necessary for:

a. the metering and control of the generating and transmission facilities.
b. the dispatch of electric power and energy; and
c. such other purposes as may be necessary for optimum operation of the system and the implementation of this Allocations Agreement.

ARTICLE VI – GENERAL

6.01 Regulatory Authorization
This Allocations Agreement is subject to regulatory approval by the Missouri Public Service Commission. UCU shall seek all necessary regulatory authorizations for this Electric Allocations Agreement.

6.02 Effect on Other Agreements
This Electric Allocations Agreement shall not modify the obligation of other agreements between the Divisions and others not parties to this Electric Allocations Agreement.

EDE – MPS ELECTRIC ALLOCATIONS AGREEMENT

This Electric Allocations Agreement is in regard to the Missouri Public Service (MPS) and Empire District Electric Company (EDE), Divisions of UtiliCorp United Inc. (UCU).

ARTICLE I – TERM OF AGREEMENT

1.01 This EDE-MPS Electric Allocations Agreement shall become effective at the closing of the Merger, or such later date as may be fixed by any required regulatory acceptance.

1.02 This EDE – MPS Electric Allocations Agreement shall continue from year-to-year thereafter until terminated by the Effective Time of Retail Competition in Missouri.

ARTICLE II – DEFINITIONS

2.01 Generation Dispatch & Energy Trading shall be a center operated by UCU solely devoted to the optimal utilization of system power resources for the supply of power and energy for MPS and EDE.

2.02 Divisions shall be MPS and EDE.

2.03 Economic Dispatch shall be the distribution of total power resource requirements among alternative sources for system economy with due consideration of system security.

ARTICLE III – PURPOSE

3.01 Purpose of This Agreement
The purpose of the EDE – MPS Electric Allocations Agreement is to provide the basis for the allocation of generation and purchased power resources and costs under the operation of UCU to achieve optimal economies consistent with reliable electric service and reasonable utilization of natural resources; and to establish the basis for capacity commitments within the Company.

ARTICLE IV – Allocations

4.01 Planning and Authorization of Generation Capacity
For planning purposes, UCU shall coordinate each Division's forecast of System Capacity to meet the overall System Capacity Responsibility and Capacity Margin.

4.02 Capacity Margin Requirements

Capacity Margin requirements for MPS and EDE shall be determined on a combined load basis and shall be in accordance with the Southwest Power Pool (SPP) and Mid-America Power Pool (MAPP) criteria for reserve planning.

4.03 Assignment of Existing Generation Capacity and Capacity Costs to Divisions
Each Division shall have assigned to it such generating capacity and associated costs as were owned or contracted for by it prior to the closing of the merger to supply its System Peak Responsibility.

4.04 Allocation of New Generation Capacity to Divisions
Prior to June 1 each year, new generation capacity owned or contracted for by UCU shall be allocated in such a way as to equalize on a pro-rata basis any capacity in excess of the respective reserve requirements of each Division. The capacity reserve margin is calculated by the following.

a. The capacity sum is the assigned existing capacity plus allocated new capacity;
b. The ratio is the capacity sum divided by the sum of the non-coincident peak demand of the Divisions; and
c. The capacity reserve margin is the ratio minus 1.

4.05 Allocation of New Generation Capacity Costs to Divisions
Unless otherwise specified, the cost of all new generation capacity owned or contracted for by MPS shall be allocated in such a way as to equalize the costs per kilowatt of new generation capacity between Divisions. The exceptions are listed below.

a. If new generation capacity is built in such a way that facilities use existing generation or generation sites assigned to a Division under 4.03, then UCU shall obtain estimates of the cost savings from the shared facilities from at least three outside sources.
b. The cost savings attributable to shared facilities will be the average of the estimates obtained from outside sources.
c. The estimated cost savings will be credited as a decrease in allocated costs to the Division with the shared facilities, and will be debited as an increase in allocated costs to other Divisions.

4.06 Economic Dispatch
The UCU Dispatch Center shall perform Economic Dispatch by scheduling energy output of the generation resources to obtain the lowest cost of energy for serving System demand consistent with operating and security constraints, including voltage control, stability, loading of facilities, operating guides, interconnection contracts fuel commitments, environmental requirements and continuity of service to customers.

4.07 Exchange With Other Utilities

The UCU Dispatch Center shall coordinate and direct off-system purchases and sales of energy necessary to meet system requirements or to improve system economy for the Divisions.

4.08 Allocation of Energy Costs

In order to maximize the economic benefits available to UCU, UCU will dispatch the power supply resources of MPS and EDE in a centralized manner (joint dispatch). To accomplish this, energy costs for EDE and MPS resulting from centralized dispatch of the combined generating units and purchased power resources will be determined in the following manner:

a. Accounting information for energy costs incurred each month will be maintained separately for each Division.
   1. Energy costs from generation resources assigned to each division under 4.03 will be assigned to that same Division.
   2. Energy costs from generation resources allocated to each Division under 4.04 will be allocated to that same Division using the same allocation factor used for allocating new generation.
   3. Energy costs from other generation resources outside the combined centers system will be allocated to each Division on equal dollars per megawatt-hour basis.

b. The RealTime® production cost model will be used to simulate monthly fuel and interchange purchases and sales using data based on actual operating statistics for the subject month. Monthly operating statistics will include data for all power resources which were utilized plus historical and anticipated performance characteristics of power resources not utilized. Generating unit operating parameters used in the RealTime® model will be established using actual hourly generation values. These operating parameters will then be adjusted, if necessary, until RealTime® model output statistics for the joint dispatch reflect actual production and interchange purchases and sale data (i.e., fuel costs, heat rates, maintenance outages, etc.) for the subject month. The monthly costs (net of profits from interchange sales) resulting from the joint dispatch of the calibrated RealTime® model will be the first component used in the overall calculations of energy costs.

c. The MPS and EDE systems will then be modeled on a stand-alone dispatch basis for the subject month. Generating unit and interchange parameters, as developed in the joint dispatch model (step b, above), will be used as input data for the stand-alone production cost simulations to be performed for each Company.

d. The stand-alone costs (step c. above) of EDE and MPS will then each be factored on an equal percentage basis to equal the total costs determined from the joint dispatch (step b. above). Subject to the conditions set out in the Regulatory Plan attachment to this Electric Allocations Agreement, the result will be the adjusted energy cost for the month for EDE and MPS.

e. The Divisions shall reconcile energy costs each month. The Division(s) which incurred additional costs during the month for the benefit of the other Division(s) shall receive from the benefiting Division(s) a credit equal to the difference between the costs incurred for the month (step a. above) and the adjusted energy cost (step d. above).

ARTICLE V – CENTRAL DISPATCH CENTER

5.01 Central Power Dispatch Center
UCU shall provide and operate a Central Power Dispatch Center (CPDC) adequately equipped and staffed to meet the requirements for efficient, economical and reliable operation as contemplated by this Electric Allocations Agreement.

5.02 Communications and Other Facilities
The CDPC shall provide communications and other facilities necessary for:

a. the metering and control of the generating and transmission facilities.
b. the dispatch of electric power and energy; and
c. such other purposes as may be necessary for optimum operation of the system and the implementation of this Allocations Agreement.

ARTICLE VI – GENERAL

6.01 Regulatory Authorization
This Allocations Agreement is subject to regulatory approval by the Missouri Public Service Commission. UCU shall seek all necessary regulatory authorizations for this Electric Allocations Agreement.

6.02 Effect on Other Agreements
This Electric Allocations Agreement shall not modify the obligation of other agreements between the Divisions and others not parties to this Electric Allocations Agreement.

ILLUSTRATIVE REGULATORY PLAN FOR ENERGY-COST OPPORTUNITIES
UCU-EDE MERGER

Allocation - Energy Related		2001	2002	2003	2004	2005	Total
Profits from Off-System Sales		$7,047,213	$20,919,770	$25,319,106	$25,942,674	$32,058,108	$111,286,871
Allocation to MPS	70.6%	$4,975,332	$14,769,358	$17,875,289	$18,315,528	$22,633,024	$78,568,531
Allocation to EDE	8.3%	$584,919	$1,736,341	$2,101,486	$2,153,242	$2,660,823	$9,236,810
Allocation to Shareholders	21.1%	$1,486,962	$4,414,071	$5,342,331	$5,473,904	$6,764,261	$23,481,530
Joint Dispatch Synergies		$3,398,252	$3,571,083	$3,805,929	$4,033,212	$4,345,709	$19,154,185
MPS Stand Alone w/o Sales		56.50%	55.23%	55.68%	55.85%	55.52%	55.74%
SJLP Stand Alone w/o Sales		43.50%	44.77%	44.32%	44.15%	44.48%	44.26%
Allocation to MPS	50%	$959,944	$986,151	$1,059,659	$1,126,300	$1,206,281	$5,338,334
Allocation to EDE		$739,182	$799,391	$843,306	$890,306	$966,573	$4,238,758
Allocation to Shareholders	50%	$1,699,126	$1,785,542	$1,902,965	$2,016,606	$2,172,855	$9,577,093

Schedule 5

ATTACHMENT
REGULATORY PLAN FOR ENERGY COSTS

This regulatory plan attachment to the Electric Allocations Agreement applies to the first X years after the completion of the merger between UCU and EDE. The purpose of this regulatory plan is to set out the treatment of energy costs for the purposes of determining revenue requirements in the setting of rates for either MPS or EDE before the Missouri Public Service Commission.

1. Stand-Alone Energy Cost Determination.
   The stand-alone energy costs for MPS and EDE shall be determined for the appropriate test year as set out in section 4.08, subsection c of the Electric Allocations Agreement except for the following modification.
   a. If the heat rate at Lake Road 4 is improved from pre-merger levels, then the heat rate used in the EDE stand-alone dispatch will be modified to its pre-merger level.
   b. The stand-alone dispatch shall be run without off-system sales.

2. Allocation of Profits from Off-System Sales
   The purpose of this calculation is to determine reduced energy costs from pre-merger levels of off-system sales and 50% of any increase in profits from increases in off-system sales from pre-merger levels.
   a. Of the test-year-normalized profits from off-system sales, 70.6% shall be allocated to MPS.
   b. Of the test-year-normalized profits from off-system sales, 8.3% shall be allocated to EDE.

3. Allocation of Savings from Joint Dispatch
   The purpose of this calculation is to determine reduced energy costs in the amount of 50% of the reduction in energy costs from the joint dispatch of power supply resources.
   a. The joint dispatch energy costs for MPS and EDE shall be determined as set out in section 4.08, subsection b of the Electric Allocations Agreement except that the joint dispatch shall be run without off-system sales.
   b. The amount of savings from joint dispatch shall be calculated as the difference between the sum of the energy costs from the stand-alone dispatches in 1 above and the joint dispatch in 3.a above.
   c. Of the savings calculated in 3.a above, 50% will be allocated between MPS and EDE based on the percent of energy costs from the stand-alone dispatches in 1 above.

4. Total Energy Costs for Purposes of Test-Year Revenue Requirements.
   For either MPS or EDE the energy costs to be included in test-year revenue requirements will be the stand-alone costs calculated in 1 above, minus both the allocation of profits from off-system sales calculated in 2 above and the allocation of savings from joint dispatch calculated in 3 above.

ALLOCATIONS OF ENERGY COST RELATED OPPORTUNITIES BETWEEN MERGERS

	FIRST 5 YEARS			
MERGER	SEPARATE	JOINT ALLOCATIONS		DIFFERENCE
UCU-SJLP	$41,823,026	38.71%	$41,152,673	-$670,353
UCU-EDE	$66,214,031	61.29%	$65,152,731	-$1,061,300
TOTAL	$108,037,057	100.00%	$106,305,404	-$1,731,653

	TEN YEAR TOTAL			
MERGER	SEPARATE	JOINT ALLOCATIONS		DIFFERENCE
UCU-SJLP	$99,542,978	37.77%	$92,953,286	-$6,589,692
UCU-EDE	$164,019,689	62.23%	$153,161,674	-$10,858,015
TOTAL	$263,562,667	100.00%	$246,114,960	-$17,447,707

MERGER APPLICANTS PROPOSED ALLOCATIONS OF ENERGY COST RELATED OPPORTUNITIES BETWEEN MERGERS

	FIRST 5 YEARS				
MERGER	SEPARATE	JOINT ALLOCATIONS		PROPOSED	DIFFERENCE
UCU-SJLP	$42,421,139	39.67%	$41,438,081	$21,926,122	-$19,511,958
UCU-EDE	$64,516,005	60.33%	$63,020,925	$82,532,886	$19,511,960
TOTAL	$106,937,144	100.00%	$104,459,006	$104,459,008	$2

	TEN YEAR TOTAL				
MERGER	SEPARATE	JOINT ALLOCATIONS		PROPOSED	DIFFERENCE
UCU-SJLP	$104,344,060	39.32%	$94,792,613	$56,978,464	-$37,814,149
UCU-EDE	$160,999,286	60.68%	$146,261,733	$184,075,888	$37,814,155
TOTAL	$265,343,346	100.00%	$241,054,346	$241,054,352	$6

ILLUSTRATIVE REGULATORY PLAN FOR ENERGY-COST OPPORTUNITIES
UCU-SJLP-EDE MERGER

Allocation - Energy Related		2001	2002	2003	2004	2005	Total
Profits from Off-System Sales		$9,439,834	$23,705,466	$29,786,942	$30,012,391	$39,809,427	$132,754,060
Allocation to MPS	64.9%	$6,126,452	$15,384,847	$19,331,725	$19,478,042	$25,836,318	$86,157,385
Allocation to SJLP	2.3%	$217,116	$545,226	$685,100	$690,285	$915,617	$3,053,343
Allocation to EDE	7.8%	$736,307	$1,849,026	$2,323,381	$2,340,966	$3,105,135	$10,354,817
Allocation to Shareholders	25.0%	$2,359,959	$5,926,367	$7,446,736	$7,503,098	$9,952,357	$33,188,515
Joint Dispatch Synergies		$6,769,117	$7,025,456	$8,028,751	$8,568,137	$9,326,815	$39,718,276
MPS Stand Alone w/o Sales		50.31%	49.05%	49.83%	49.96%	49.77%	49.79%
SJLP Stand Alone w/o Sales		10.94%	11.20%	10.52%	10.55%	10.35%	10.68%
EDE Stand Alone w/o Sales		38.74%	39.76%	39.65%	39.49%	39.88%	39.53%
Allocation to MPS		$1,702,941	$1,722,855	$2,000,183	$2,140,367	$2,320,883	$9,887,229
Allocation to SJLP	50%	$370,308	$393,296	$422,392	$451,805	$482,838	$2,120,640
Allocation to EDE		$1,311,310	$1,396,577	$1,591,800	$1,691,896	$1,859,686	$7,851,269
Allocation to Shareholders	50%	$3,384,559	$3,512,728	$4,014,376	$4,284,069	$4,663,408	$19,859,138

Market Shares of Relevant Economic Capacity by Month and Load Duration
UCU-EDE Merger

LCG Reported Market Shares	Jan-99		Feb-99		Mar-99		Apr-99		May-99		Jun-99	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Associated Electric Coop	2,285	2,236	2,285	2,220	1,742	1,683	2,203	2,147	1,509	1,491	2,285	2,220
City of Independence	126	126	126	126	126	126	126	126	126	126	126	59
Board of Public Utilities-KC, KS	418	418	418	418	418	418	418	418	279	287	411	411
Kansas City Power & Light	2,354	2,388	2,565	2,401	1,827	1,655	2,119	1,975	2,796	2,571	2,796	2,423
Munis in Kansas	50	0	0	0	0	0	0	0	0	0	23	0
Munis in Missouri	34	23	34	23	34	23	23	23	23	23	84	23
City of Springfield	381	381	381	381	381	381	325	323	189	192	381	381
Southwestern Pwr Adm	1,270	0	1,346	0	1,270	0	961	0	1,181	0	1,209	0
Western Resources	3,890	3,797	3,734	3,499	3,059	3,093	2,981	2,750	2,890	2,839	3,968	3,173
Imports from MAIN	1,067	761	1,657	717	1,064	146	617	76	1,151	586	1,506	381
Imports from MAPP	47	98	364	0	682	224	728	552	737	260	740	77
Imports from SPP	554	383	225	182	558	488	536	491	456	343	545	411
UtiliCorp	456	456	456	456	456	456	456	456	232	245	464	368
St Joseph L&P	93	93	93	0	93	70	93	70	93	23	93	0
Empire District Electric	320	286	320	286	320	286	318	286	160	164	319	286
Total MW	13,345	11,446	14,004	10,709	12,030	9,049	11,904	9,693	11,822	9,150	14,950	10,213
Total Hours	400	344	366	306	400	344	499	221	358	386	350	370
UtiliCorp Market Share	3.42%	3.98%	3.26%	4.26%	3.79%	5.04%	3.83%	4.70%	1.96%	2.68%	3.10%	3.60%
SJLP Market Share	0.70%	0.81%	0.66%	0.00%	0.77%	0.77%	0.78%	0.72%	0.79%	0.25%	0.62%	0.00%
EDE Market Share	2.40%	2.50%	2.29%	2.67%	2.66%	3.16%	2.67%	2.95%	1.35%	1.79%	2.13%	2.80%
Merged Market Share MW	776	742	776	742	776	742	774	742	392	409	783	654
Merged Market Share %	5.81%	6.48%	5.54%	6.93%	6.45%	8.20%	6.50%	7.66%	3.32%	4.47%	5.24%	6.40%
Premerger HHI	**1,663**	**2,022**	**1,588**	**2,102**	**1,376**	**1,964**	**1,480**	**1,832**	**1,584**	**2,108**	**1,522**	**2,083**
Change in HHI	**22**	**25**	**20**	**30**	**27**	**41**	**27**	**36**	**7**	**13**	**17**	**28**

Schedule 9.1

Market Shares of Relevant Economic Capacity by Month and Load Duration
UCU-EDE Merger

LCG Reported Market Shares	Jul-99		Aug-99		Sep-99		Oct-99		Nov-99		Dec-99	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Associated Electric Coop	2,285	2,236	2,285	2,236	2,285	2,220	1,661	1,623	2,285	2,236	2,285	2,236
City of Independence	126	126	126	126	126	59	126	126	126	126	126	126
Board of Public Utilities-KC, KS	418	418	418	418	418	323	418	418	418	418	418	418
Kansas City Power & Light	2,831	2,796	2,831	2,796	2,796	2,461	2,796	2,571	2,796	2,686	2,796	2,796
Munis in Kansas	310	0	124	0	23	0	0	0	0	0	0	0
Munis in Missouri	114	23	75	23	23	23	34	23	34	23	34	23
City of Springfield	421	381	381	381	381	381	381	381	381	381	381	381
Southwestern Pwr Adm	1,060	0	1,079	0	1,121	0	1,039	0	1,312	0	1,435	0
Western Resources	4,390	3,797	4,338	3,797	3,890	3,185	3,130	3,054	3,797	3,743	3,797	3,797
Imports from MAIN	1,541	887	1,964	1,076	1,059	167	862	415	1,057	339	1,291	963
Imports from MAPP	1,121	510	1,741	884	544	15	277	42	532	129	406	700
Imports from SPP	812	306	562	261	446	476	392	326	419	296	454	304
UtilCorp	564	456	533	456	456	380	456	456	456	456	456	456
St Joseph L&P	93	70	93	93	93	23	93	70	93	70	93	93
Empire District Electric	430	286	393	286	319	286	293	286	295	286	296	286
Total MW	16,516	12,292	16,943	12,833	13,980	9,999	11,958	9,791	14,001	11,189	14,268	12,579
Total Hours	399	345	392	352	351	369	407	337	387	333	354	390
UtiliCorp Market Share	3.41%	3.71%	3.15%	3.55%	3.26%	3.80%	3.81%	4.66%	3.26%	4.08%	3.20%	3.63%
SJLP Market Share	0.56%	0.57%	0.55%	0.72%	0.67%	0.23%	0.78%	0.71%	0.66%	0.63%	0.65%	0.74%
EDE Market Share	2.60%	2.33%	2.32%	2.23%	2.28%	2.86%	2.45%	2.92%	2.11%	2.56%	2.07%	2.27%
Merged Market Share MW	994	742	926	742	775	666	749	742	751	742	752	742
Merged Market Share	6.02%	6.04%	5.47%	5.78%	5.54%	6.66%	6.26%	7.58%	5.36%	6.63%	5.27%	5.90%
Premerger HHI	**1,426**	**1,920**	**1,436**	**1,814**	**1,622**	**2,187**	**1,613**	**2,032**	**1,601**	**2,163**	**1,581**	**1,857**
Change in HHI	**24**	**22**	**20**	**20**	**20**	**30**	**24**	**35**	**18**	**27**	**17**	**21**

Schedule 9.2

Market Shares of Relevant Economic Capacity by Month and Load Duration
UCU-SJLP-EDE Merger

LCG Reported Market Shares	Jan-99		Feb-99		Mar-99		Apr-99		May-99		Jun-99	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Associated Electric Coop	2,285	2,236	2,285	2,220	1,742	1,683	2,203	2,147	1,509	1,491	2,285	2,220
City of Independence	126	126	126	126	126	126	126	126	126	126	126	59
Board of Public Utilities-KC, KS	418	418	418	418	418	418	418	418	279	287	411	411
Kansas City Power & Light	2,354	2,388	2,565	2,401	1,827	1,655	2,119	1,975	2,796	2,571	2,796	2,423
Munis in Kansas	50	0	0	0	0	0	0	0	0	0	23	0
Munis in Missouri	34	23	34	23	34	23	23	23	23	23	84	23
City of Springfield	381	381	381	381	381	381	325	323	189	192	381	381
Southwestern Pwr Adm	1,270	0	1,346	0	1,270	0	961	0	1,181	0	1,209	0
Western Resources	3,890	3,797	3,734	3,499	3,059	3,093	2,981	2,750	2,890	2,839	3,968	3,173
Imports from MAIN	1,067	761	1,657	717	1,064	146	617	76	1,151	586	1,506	381
Imports from MAPP	47	98	364	0	682	224	728	552	737	260	740	77
Imports from SPP	554	383	225	182	558	488	536	491	456	343	545	411
UtiliCorp	456	456	456	456	456	456	456	456	232	245	464	368
St Joseph L&P	93	93	93	0	93	70	93	70	93	23	93	0
Empire District Electric	320	286	320	286	320	286	318	286	160	164	319	286
Total MW	13,345	11,446	14,004	10,709	12,030	9,049	11,904	9,693	11,822	9,150	14,950	10,213
Total Hours	400	344	366	306	400	344	499	221	358	386	350	370
UtiliCorp Market Share	3.42%	3.98%	3.26%	4.26%	3.79%	5.04%	3.83%	4.70%	1.96%	2.68%	3.10%	3.60%
SJLP Market Share	0.70%	0.81%	0.66%	0.00%	0.77%	0.77%	0.78%	0.72%	0.79%	0.25%	0.62%	0.00%
EDE Market Share	2.40%	2.50%	2.29%	2.67%	2.66%	3.16%	2.67%	2.95%	1.35%	1.79%	2.13%	2.80%
Merged Market Share MW	869	835	869	742	869	812	867	812	485	432	876	654
Merged Market Share %	6.51%	7.30%	6.21%	6.93%	7.22%	8.97%	7.28%	8.38%	4.10%	4.72%	5.86%	6.40%
Premerger HHI	**1,663**	**2,022**	**1,588**	**2,102**	**1,376**	**1,964**	**1,480**	**1,832**	**1,584**	**2,108**	**1,522**	**2,083**
Change in HHI	**24**	**30**	**22**	**23**	**30**	**45**	**31**	**39**	**11**	**12**	**20**	**20**

Market Shares of Relevant Economic Capacity by Month and Load Duration
UCU-SJLP-EDE Merger

LCG Reported	Jul-99		Aug-99		Sep-99		Oct-99		Nov-99		Dec-99	
Market Shares	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
Associated Electric Coop	2,285	2,236	2,285	2,236	2,285	2,220	1,661	1,623	2,285	2,236	2,285	2,236
City of Independence	126	126	126	126	126	59	126	126	126	126	126	126
Board of Public Utilities-KC, KS	418	418	418	418	418	323	418	418	418	418	418	418
Kansas City Power & Light	2,831	2,796	2,831	2,796	2,796	2,461	2,796	2,571	2,796	2,686	2,796	2,796
Munis in Kansas	310	0	124	0	23	0	0	0	0	0	0	0
Munis in Missouri	114	23	75	23	23	23	34	23	34	23	34	23
City of Springfield	421	381	381	381	381	381	381	381	381	381	381	381
Soutwestern Pwr Adm	1,060	0	1,079	0	1,121	0	1,039	0	1,312	0	1,435	0
Western Resources	4,390	3,797	4,338	3,797	3,890	3,185	3,130	3,054	3,797	3,743	3,797	3,797
Imports from MAIN	1,541	887	1,964	1,076	1,059	167	862	415	1,057	339	1,291	963
Imports from MAPP	1,121	510	1,741	884	544	15	277	42	532	129	406	700
Imports from SPP	812	306	562	261	446	476	392	326	419	296	454	304
UtilCorp	564	456	533	456	456	380	456	456	456	456	456	456
St Joseph L&P	93	70	93	93	93	23	93	70	93	70	93	93
Empire District Electric	430	286	393	286	319	286	293	286	295	286	296	286
Total MW	16,516	12,292	16,943	12,833	13,980	9,999	11,958	9,791	14,001	11,189	14,268	12,579
Total Hours	399	345	392	352	351	369	407	337	387	333	354	390
UtiliCorp Market Share	3.41%	3.71%	3.15%	3.55%	3.26%	3.80%	3.81%	4.66%	3.26%	4.08%	3.20%	3.63%
SJLP Market Share	0.56%	0.57%	0.55%	0.72%	0.67%	0.23%	0.78%	0.71%	0.66%	0.63%	0.65%	0.74%
EDE Market Share	2.60%	2.33%	2.32%	2.23%	2.28%	2.86%	2.45%	2.92%	2.11%	2.56%	2.07%	2.27%
Merged Market Share MW	1,087	812	1,019	835	868	689	842	812	844	812	845	835
Merged Market Share	6.58%	6.61%	6.01%	6.51%	6.21%	6.89%	7.04%	8.29%	6.03%	7.26%	5.92%	6.64%
Premerger HHI	**1,426**	**1,920**	**1,436**	**1,814**	**1,622**	**2,187**	**1,613**	**2,032**	**1,601**	**2,163**	**1,581**	**1,857**
Change in HHI	**25**	**24**	**21**	**24**	**22**	**25**	**28**	**38**	**21**	**29**	**20**	**25**