Exhibit No.: ____________
Issue(s): Allocation of Joint Dispatch Benefits/ Off-System Sales Margin/ Purchased Power Expense
Witness/Type of Exhibit: Dittmer/Rebuttal
Sponsoring Party: Public Counsel
Case No.: EC-2002-1

REBUTTAL TESTIMONY

OF

JAMES R. DITTMER

Submitted on Behalf of
the Office of the Public Counsel

UNION ELECTRIC COMPANY

Case No. EC-2002-1

NP

May 10, 2002

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF JAMES R. DITTMER

STATE OF Missouri)
) SS
COUNTY OF JACKSON)

James R. Dittmer, of lawful age and being first duly sworn, deposes and states:

1) My name is James R. Dittmer. I am a Senior Regulatory Consultant working for the firm of Utilitech, Inc. This testimony I am presenting herein is offered on behalf of the Missouri Office of the Public Counsel
2) Attached hereto and made a part hereof for all purposes is my rebuttal testimony consisting of pages 1 through 29.
3) I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

James R. Dittmer

Subscribed and sworn to be this 9th day of May 2002

Roseanne Mertes
Notary Public

ROSEANNE MERTES
NOTARY PUBLIC STATE OF MISSOURI
JACKSON COUNTY
MY COMMISSION EXP DEC 7,2002

My commission expires 12-7-02

REBUTTAL TESTIMONY
OF
JAMES R. DITTMER
UNION ELECTRIC COMPANY
d/b/a AMERENUE
CASE NO. EC-2002-1

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc., a consulting firm engaged primarily in utility rate work. The firm's engagements include review of utility rate applications on behalf of various federal, state and municipal governmental agencies as well as industrial groups. In addition to utility intervention work, the firm has been engaged to perform special studies for use in utility contract negotiations.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Utilitech, Inc. has been retained by the Office of the Public Counsel for the State of Missouri (hereinafter "OPC") to review limited areas of AmerenUE's (hereinafter "UE" or "Company") Missouri retail jurisdictional cost of service within the ongoing Missouri Public Service Commission (hereinafter "MPSC" or "Commission") earnings investigation proceeding – Case No. EC-2002-1. As a result of the investigation I have been able to perform to date, I am sponsoring this rebuttal testimony on behalf of the Missouri Office of the Public Counsel.

Q. PLEASE BRIEFLY STATE WHAT ISSUES OR TOPICS YOU WILL BE ADDRESSING WITHIN YOUR REBUTTAL TESTIMONY?

A. My analyses in this case have been limited to the areas of fuel costs, purchased power expense and off-system sales margins to be considered within the development of UE's Missouri retail jurisdictional cost of service.

I. QUALIFICATIONS

Q. BEFORE DISCUSSING IN GREATER DETAIL THE ISSUES YOU BRIEFLY DESCRIBED ABOVE, PLEASE STATE YOUR EDUCATIONAL BACKGROUND?

A. I graduated from the University of Missouri - Columbia, with a Bachelor of Science Degree in Business Administration, with an Accounting Major, in 1975. I hold a Certified Public Accountant Certificate in the State of Missouri. I am a member of the American Institute of Certified Public Accountants, and the Missouri Society of Certified Public Accountants.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. Subsequent to graduation from the University of Missouri, I accepted a position as auditor for the Missouri Public Service Commission. In 1978, I was promoted to Accounting Manager of the Kansas City Office of the Commission

Staff. In that position, I was responsible for all utility audits performed in the western third of the State of Missouri. During my service with the Missouri Public Service Commission, I was involved in the audits of numerous electric, gas, water and sewer utility companies. Additionally, I was involved in numerous fuel adjustment clause audits, and played an active part in the formulation and implementation of accounting staff policies with regard to rate case audits and accounting issue presentations in Missouri. In 1979, I left the Missouri Public Service Commission to start my own consulting business. From 1979 through 1985 I practiced as an independent regulatory utility consultant. In 1985, Dittmer, Brosch and Associates was organized. Dittmer, Brosch and Associates, Inc. changed its name to Utilitech, Inc in 1992.

My professional experience since leaving the Missouri Public Service Commission has consisted primarily of issues associated with utility rate, contract and acquisition matters. For the past twenty-two years, I have appeared on behalf of clients in utility rate proceedings before various federal and state regulatory agencies. In representing those clients, I performed revenue requirement studies for electric, gas, water and sewer utilities and testified as an expert witness on a variety of rate matters. As a consultant, I have filed testimony on behalf of industrial consumers, consumer groups, the Missouri Office of the Public Counsel, the Missouri Public Service Commission Staff, the Indiana Utility Consumer Counselor, the Mississippi Public Service Commission Staff, the Arizona Corporation Commission Staff, the Arizona

Residential Utility Consumer Office, the Nevada Office of the Consumer Advocate, the Washington Attorney General's Office, the Hawaii Consumer Advocate's Staff, the Oklahoma Attorney General's Office, the West Virginia Public Service Commission Consumer Advocate's Staff, municipalities and the Federal government before regulatory agencies in the states of Arizona, Michigan, Missouri, Ohio, Florida, Colorado, Hawaii, Kansas, Mississippi, New Mexico, Nevada, New York, West Virginia, Washington and Indiana, as well as the Federal Energy Regulatory Commission.

II. COMPANY-WIDE FUEL AND PURCHASED POWER EXPENSE

Q. IF THAT CONCLUDES YOUR DISCUSSION OF YOUR QUALIFICATIONS, PLEASE CONTINUE BY DESCRIBING THE GOALS OF YOUR VARIOUS ANALYSES UNDERTAKEN IN THIS CASE, AS WELL AS THE STEPS EMPLOYED WITH SUCH ANALYSES.

A. Stated simply, my goals are to undertake steps to ensure that UE's rates are developed by considering an ongoing, normal level of prudently incurred fuel and purchased power costs properly assigned or allocated to Missouri retail operations, and further, that rates being established consider as an off-set to the otherwise-calculated jurisdictional cost of service a level of margins from off-system sales that can reasonably be expected to occur on an ongoing basis.

While the goals established are simple and easy to describe, the development of an ongoing level of fuel and purchased power expense is not particularly simple or easy to develop. Specifically, the "ongoing" level of fuel expense is a product of a number of variables affecting any given utility's generating units' output – including fuel/transportation prices, unit availability and unit efficiency. Each of these significant variables need to be analyzed, and ultimately "normalized" in order to determine a reasonable and ongoing level of fuel and purchased power expense. Utilities and regulatory staffs routinely employ production simulation models which consider a number of normalized inputs (i.e., variables) in an attempt to arrive at a "normalized" cost of fuel and purchased power expense.

Similarly, developing or determining an ongoing level of margins from off-system sales can be challenging. Ultimately, the margins to be derived will be dependent upon available capacity, the efficiency and operating costs of the utility with available capacity and energy to sell off-system, as well as market conditions for wholesale power during the period that rates will be in effect.

The way this case has been structured, the MPSC Staff is essentially the "moving party." As such, the MPSC Staff has come forward first by use of a production cost simulation model to propose an ongoing level of fuel and purchased power expense. Accordingly, the testimony offered herein is responsive to the MPSC Staff's proposed level of fuel and purchased power expense that was developed with the Staff's RealTime production costing model.

Q. HAVE YOU ALSO DEVELOPED A PRODUCTION COSTING MODEL WITH WHICH TO TEST THE RESULTS OF THE STAFF'S RECOMMENDATIONS REGARDING FUEL AND PURCHASED POWER COSTS?

A. No. Given resource constraints, it was never envisioned within this engagement that an independent production costing model would be run. Accordingly, my analysis has been limited to reviewing AmerenUE's and Ameren Energy Generating Company's ("AEG") historic actual costs, generating unit efficiency and output over a multi-month and multi-year period to determine if what the Staff – and eventually the Company – is predicting to be an ongoing level of fuel and purchased power expense appears reasonable. At this point I should caution that history cannot always and exclusively be employed to predict the future. Fuel prices change, units can become degraded over time, and occasionally units are refurbished or "repowered" to enhance efficiency. Any of these events can cause future operating results and costs to deviate from past performance and cost levels. However, if predicted future operating results and costs deviate significantly from historical results, one should be able to identify the variable that has significantly changed and determine whether the assumption for the variable is reasonable for the future.

Q. COULD YOU BRIEFLY DESCRIBE THE STEPS THAT YOU HAVE UNDERTAKEN IN YOUR ATTEMPT TO DETERMINE WHETHER THE FUEL AND PURCHASED POWER COST PREDICTION EMBODIED WITHIN THE STAFF'S PRODUCTION COST MODEL RUN IS REASONABLE?

A. Yes. I have prepared monthly and twelve-month-ending data bases for each UE and AEG base load generating station that reflect actual production output (MWH's generated), net fuel cost per MWH generated and station efficiency (average heat rates – calculated by dividing total MMBtu consumed by net MWH's generated). These three statistics for each AEG and UE generating station were compared to the predictions resulting from the Staff's production costing model.

Similarly, I analyzed monthly and twelve-month-ending MWH's purchases and related costs for AEG and UE by purchase power category. These results were also compared to the Staff's production costing model.

Q. DID YOUR HISTORIC REVIEW OR ANALYSIS INDICATE A PROBLEM OR CONCERN WITH THE STAFF'S PRODUCTION COSTING MODEL OUTPUT?

A. No. However, at this point I would note a couple of items. First, the Staff's production run was calibrated to consider only native load and firm wholesale requirements of UE and AEG. It did not attempt to model generation and related costs for anticipated non-firm off-system sales. AEG and UE, like virtually every utility, will attempt to make off-system sales whenever the price that can be obtained is above the Company's variable running costs. The historic data that I was comparing to Staff's production run reflects production and costs related to facilitating some level of off-system sales. As such, it can be expected that there will be some difference in historic results versus results forecasted by Staff's production run.

Second, as discussed in Staff witness Dr. Michael Proctor's testimony, Staff has assumed within its production cost run that 500 megawatts of capacity that was supplied from AEG during the test year instead be supplied by new combustion turbine units added by UE. It is for this reason I have not devoted much effort trying to reconcile historic operating results of UE's and AEG's peaking units with that predicted in Staff's production run. The historic production of AEG's and UE's peaking units – which additionally would have been run in part to meet off-system sales that would not be reflected with in Staff's production run – would be expected to be replaced in Staff's production run with new, more efficient gas fired combustion turbines. Finally on this point, I note that only a relatively small amount of generation comes from peaking units at this time.

Third, the historic data provided by the Company was limited to "station" statistics whereas the Staff's model was run by considering unit-specific inputs. Accordingly, my analysis was limited to a "station" level of detail.

In light of the differences and data constraints in comparing historical results with Staff's production costing run forecasted results, the analyses undertaken cannot be expected to identify relatively-minor modeling or input problems that could be identified by performing an independent production cost run. The analysis undertaken should, however, be able to identify major problems or concerns with the Staff's production cost model. Finally, I note that at this point in time the majority of UE's native load continues to be met with its base load nuclear and coal units. The availability, efficiency and fuel prices for these units have remained relatively stable for the past three years. Such stability has been reflected within Staff's production cost run. Accordingly, the margin for error in estimating the majority of UE's fuel costs incurred to meet native load should be relatively small.

Q. WHAT FUEL PRICES DID STAFF ASSUME WHEN UNDERTAKING ITS PRODUCTION COST RUN?

A. According to Mr. John Cassidy's testimony, Staff utilized test year actual fuel prices paid.

Q. DO YOU AGREE WITH THIS IMPORTANT INPUT ASSUMPTION?

A. Analysis and review performed to date would indicate that such input assumption is reasonable as it relates to non-gas fuel costs. That stated, I would admit that I have not reviewed all fuel and transportation contracts in effect during the historic test year or during the "fixed, known and measurable" period ending September, 2001. Of the contracts reviewed to date, I did not observe a significant modification or amendment that might indicate or suggest that a "price" normalization adjustment was necessary or appropriate.

Additionally, I have reviewed the actual price per MMBtu of fuel burned at each of UE's and AEG's base load generating stations by month during the test year and for the months July through December 2001. The price per MMBtu burned would consider the delivered cost of fuel – or in other words, the price of fuel plus transportation. The test year and post-test year prices observed generally support a conclusion that no major changes have occurred during the test year or during the fixed, known and measurable period. Thus, this analysis would also support use of test year actual non-gas prices incurred in the development of the Staff's production cost run.

If the Company's rebuttal testimony should identify a significant and ongoing change in fuel or transportation costs, it may be appropriate to modify Staff's production cost model to capture such event. However, as previously stated, based upon analyses undertaken to date, the Staff's use of actual test year non-gas fuel prices appears reasonable in this case.

III. OFF-SYSTEM SALES MARGINS

Q. AT THE OUTSET OF YOUR TESTIMONY YOU INDICATED THAT YOU WERE ALSO ENGAGED TO REVIEW OFF-SYSTEM SALES MARGINS. BASED UPON YOUR REVIEW TO DATE, DO YOU HAVE ANY ADJUSTMENTS TO PROPOSE TO STAFF'S LEVEL OF OFF-SYSTEM SALES MARGINS REFLECTED WITHIN THE DEVELOPMENT OF STAFF'S JURISDICTIONAL COST OF SERVICE?

A. No. However, I have not fully analyzed this area as intended. Just obtaining and eventually evaluating the UE and AEG generating station output and price data has consumed the majority of time and resources that I have devoted to this engagement. I have obtained and compared AEG and UE megawatt hour sales and gross dollars received for off-system sales by month and by year for the period January 1999 through December 2001. However, I have not been able to obtain or calculate the cost of making or facilitating such sales which is essential to derive "margins" from off-system sales.

Although I have observed that gross sales declined somewhat in months following the end of the test year, I have not been able to obtain "margin" data from such sales -- which is the only true relevant statistic for cost of service development purposes. If UE should take exception to the Staff's proposed level (i.e., test year actual) of off-system sales margins, I will attempt to further analyze this issue area – which could result in the submission of surrebuttal testimony. For now, however, I have no incremental adjustment to propose to Staff's cost of service to reflect additional or fewer off-system sales margins – a level of margins that considers test year actual achievements.

IV. JOINT DISPATCH SAVINGS – INEQUITIES IN TRANSFER ENERGY PRICING

Q. THUS FAR IT WOULD APPEAR THAT YOU HAVE NOT TAKEN EXCEPTION TO ANY CALCULATIONS OR PROPOSALS REGARDING NON-GAS FUEL EXPENSE, PURCHASED POWER COSTS AND OFF-SYSTEMS SALES MARGINS EMBODIED WITHIN STAFF'S REVENUE REQUIREMENT RECOMMENDATION IN THIS CASE. DO YOU TAKE EXCEPTION TO ANYTHING THAT THE MPSC STAFF HAS CALCULATED OR RECOMMENDED REGARDING THE LEVEL OF FUEL AND PURCHASED POWER EXPENSE TO BE CONSIDERED IN THE DEVELOPMENT OF THE MISSOURI RETAIL JURISDICTIONAL COST OF SERVICE?

A. Yes. Staff's apparent adherence to the terms of the current Joint Dispatch Agreement ("JDA") between Union Electric Company, Central Illinois Public Service Company and Ameren Generating Company regarding the price of energy transferred from a "long" company to a "short" company has resulted in a significant under-allocation or under-assignment of joint dispatch savings to AmerenUE and ultimately Missouri retail ratepayers. On behalf of the MPSC Staff, Dr. Michael Proctor explains that under joint dispatch, when either UE or

AEG generates more energy than is needed to meet its load requirements in a given hour (i.e., a "long" company), such excess energy is transferred and effectively sold at the "long" company's incremental cost of producing the energy transferred to the receiving or purchasing company (i.e., the "short" company). Dr. Proctor goes on to explain how the "long" or "selling" utility actually foregoes the opportunity to sell energy at a "market price" when it transfers the energy generated in excess of its load requirement to the sister company at incremental cost (i.e., no profit margin included). Dr. Proctor utilizes this "foregone opportunity" reasoning as partial support for his proposed allocation of off-system sales margin on the basis of each company's "Resource Output" rather than the current JDA-provided "Load Requirements" basis.

My read of Dr. Proctor's testimony is that he starts to hit upon a significant problem in the current JDA regarding transfer pricing of energy. However, ultimately Dr. Proctor utilizes the inequity in a first problem identified as partial logic for fixing a second problem with the JDA – namely, the allocation of off-system sales margins on the basis of "Load Requirements" rather than the more appropriate basis of "Resource Output." Accordingly, while I do not take exception to Dr. Proctor's proposed allocation of off-system sales margins on the basis of "Resource Output," I believe a second calculation or adjustment is proper, and indeed necessary and equitable, to fairly reallocate joint dispatch savings between participants. As I shall describe in more detail in a moment, the reallocation of joint dispatch savings is necessary to cure an inequity that exists when a "long" company is required to sell to the "short" company at incremental cost. More specifically, under current transfer pricing established within the JDA, no consideration is given to foregone opportunities to sell such energy on the market or the savings the "short" company enjoys by the avoidance of higher incremental costs that it would have incurred if it had generated such energy utilizing its own production resources or bought at higher market prices.

Q. BY WAY OF BACKGROUND, PLEASE DESCRIBE WHY JOINTLY OWNED AND INTERCONNECTED UTILITY COMPANIES UNDERTAKE JOINT DISPATCHING.

A. First, at the risk of stating the obvious, joint dispatching is undertaken to derive cost savings and benefits that could not be obtained from separately dispatching two stand-alone systems. Joint dispatching should always result in savings. There should never be a situation where joint dispatching results in higher costs/smaller benefits than that achievable if the two systems were dispatched on stand-alone bases.

The actual savings through joint dispatch are achieved by virtue of the fact that the combined entity can run the combined fleet of generating units more efficiently and economically than the two systems can run their individual portfolios of generating units. In addition to lowering production costs, joint dispatch can, at times, result in higher off-system sales margins by virtue of achieving already-noted lower joint production cost that allows the combined entity to be more competitive in the wholesale market.

Q. PLEASE EXPAND UPON YOUR PREVIOUS STATEMENT EXPLAINING HOW THE COMBINED COST OF JOINTLY DISPATCHING THE UE AND AEG SYSTEMS WILL LEAD TO LOWER COMBINED COSTS THAN THE SUM OF THE TWO STAND-ALONE SYSTEMS.

The AEG and UE generating units have varying generating efficiencies and fuel sources with large fuel price differences. In UE's case, the Callaway nuclear generating unit has the lowest fuel price (if we exclude the de minimus amount of hydro power available UE's system). Callaway's variable fuel and O&M cost is but a fraction of the cost of AEG's gas-fired turbines. Further, both UE and AEG have numerous coal-fired plants whose variable production costs typically fall in between the price of nuclear and gas-fired generation. Finally, the various coal-fired plants owned by UE and AEG have different fuel sources and fuel/transportation prices as well as differing operating efficiencies that contribute to a different energy costs per net MWH generated at each plant site.

A utility should strive to continually minimize production costs by running its lowest cost generating units to their maximum capability before generating or purchasing from a higher cost source within its available power supply portfolio. When two systems such as UE and AEG are jointly dispatched, the loading or dispatch order will be somewhat different on a combined basis than what would occur if the two systems were dispatched on stand-alone bases. While total generation and purchases necessary to meet the sum of the two participants' load requirements will be the same with joint or stand-alone dispatch, the resources employed under joint dispatch will almost always be somewhat different than what would have occurred on the two stand-alone systems. Thus, under joint dispatch, an individual participant's generation output in any given hour will seldom match exactly its load requirements. In other words, there will effectively be a continuous transferring or "selling" of energy from one participant's resources to more economically meet the other participant's load requirements.

Q. WHAT IS THE PURPOSE OF A JOINT DISPATCH AGREEMENT?

A Joint Dispatch Agreement documents a systematic approach to allocating costs and benefits between the two participants to the agreement. Dr. Proctor has already described in his testimony how the current JDA allocates margins from off-system sales on the basis of UE and AEG's "Load Requirement." Other portions of the JDA describe how generation costs, purchases, and revenues from providing transmission services are to be assigned/allocated to the two participants. Additionally, the document also establishes some operating guidelines and administrative processes.

Q. WITH THAT BACKGROUND IN MIND, PLEASE EXPAND UPON THE INEQUITY YOU PERCEIVE IN THE JDA AND ULTIMATELY THE WAY IN WHICH THE STAFF'S CALCULATIONS ASSIGN COSTS AND BENEFITS BETWEEN THE TWO JDA PARTICIPANTS.

A. The current JDA provides that when a participant generates more energy with its individually-owned production resources than was necessary to meet its own load requirements, such energy – referred to in the JDA as "System Energy Transfer" – be reimbursed by the participant receiving the energy at the generating company's or transferor's Incremental Cost of the Generating Resources supplying the energy. In other words, the participant that generated energy in excess of its load requirements (i.e., the "long" or transferor company) will receive credit for incremental costs incurred in generating such energy – but it will receive no additional margin or contribution toward its fixed costs when making the transfer or sale.

As briefly mentioned at the outset of this section of testimony, effectively selling excess energy "at cost" is unfair to the "long" or "selling" utility inasmuch as it fails to consider opportunities foregone to sell such energy off-system at higher "market" or "split-the-savings" prices.

Q. IF THE INDIVIDUAL PARTICIPANTS TO THE JDA ARE SOMETIMES "PURCHASERS" AND SOMETIMES "SELLERS" OF "TRANSFER ENERGY," DOES THE INEQUITY OF SELLING "AT

COST" TEND TO GET BALANCED OUT WHEN THAT UTILITY IS ABLE TO BUY "AT COST" RATHER THAN AT "MARKET" OR "SPLIT-THE-SAVINGS" PRICES?

A. It would be purely coincidental if that result happened overtime. As Dr. Proctor has already pointed out in direct testimony, this outcome is not occurring at this point in time:

> On the average throughout this twelve-month period (i.e., twelve months ending June 30, 2001), UE is providing just over ** ___ ** of the Resource Output, but only has ** _____ ** of the Load Requirements. Two periods where these differences are smaller are: 1) the peak summer months of July and August; and 2) the months when the Callaway nuclear plant was down for refueling in April and May 2001. However, even in these months, UE's Resource Output exceeds its Load Requirements. (Dr. Michael Proctor Direct, page 10)

Q. YOU HAVE NOW STATED SEVERAL TIMES THAT THE "LONG" COMPANY MISSES THE OPPORTUNITY TO SELL AT A HIGHER MARKET PRICE OR "SPLIT-THE-SAVINGS" PRICE WHEN, PURSUANT TO PROCEDURES DESCRIBED WITHIN THE JDA, IT SELLS "AT COST." PLEASE EXPAND UPON WHAT YOU MEAN WHEN YOU STATE THAT THE LONG UTILITY MISSES THE OPPORTUNITY TO SELL AT A "SPLIT-THE-SAVINGS" PRICE?

A. Historically neighboring interconnected utilities entered into agreements whereby if both had capacity available to meet their load requirements in a given hour, the utility with the lower incremental energy costs would, nonetheless, agree to sell such short term non-firm energy at a price that was established at the half-way point between, or average of, the selling utility's incremental cost of producing the energy and the purchasing company's avoided cost of producing the energy utilizing its own generating resources. In such "economy" or "split-the-savings" transactions, both parties would share equally in the benefits of the energy transfer. The selling company achieved a margin above its incremental cost incurred to facilitate the sale, and the purchasing utility saved more than just its avoided cost of generating the required energy utilizing its own resources. These transactions resulted in a "win-win" situation.

Such split-the-savings pricing which occurs within the economy transactions just described, contrasts with the JDA System Energy Transfer pricing which essentially results in one significant "winner" (i.e., the purchaser) and one participant who can at best expect to "break even" (i.e., the producer who sells at incremental cost). Almost implicit in such JDA pricing provision is an assumption that such energy could not have been sold elsewhere at a price greater than incremental cost. It is this implicit pricing assumption for System Energy Transfers that leads to an inequitable allocation of joint dispatch savings to Missouri retail customers.

Q. IS IT, THEREFORE, YOUR PROPOSAL THAT, FOR PURPOSES OF DEVELOPING AN ONGOING LEVEL OF FUEL AND

PURCHASED POWER EXPENSE FOR UE MISSOURI RETAIL JURISDICTIONAL COST OF SERVICE INCLUSION, THAT STAFF RERUN THE REALTIME PRODUCTION COST MODEL TO REPRICE SYSTEM ENERGY TRANSFERS AT A "SPLIT-THE-SAVINGS" PRICE DEVELOPED FOR EACH HOUR OF THE TEST YEAR?

A. No. Such calculation would be an acceptable resolution to the inequity identified. However, I do not believe that such a labor and data intensive calculation is necessary – assuming it is even practically possible. Rather, I believe an equitable allocation of joint dispatch savings can be easily calculated utilizing output from the Staff's existing RealTime production cost runs.

Q. PLEASE EXPLAIN.

A. As explained in the testimony of Staff witness Mr. Leon Bender, Staff performed three production cost simulation runs – a joint dispatch run, a UE stand-alone run and an AEG stand-alone run. My understanding is that the stand-alone runs were calibrated to the joint dispatch run – or in other words, considered input variables that were identical to those used in the joint dispatch run. The obvious significant exception was that the stand-alone runs considered only the load requirements and resource capabilities of the individual stand-alone entities.

Because Staff has already performed a joint dispatch as well as stand-alone runs, the data already exists to calculate total savings from joint dispatch. Thus, one can easily and quickly calculate a revised UE and AEG "normalized and annualized" level of fuel and purchased power expense by simply deducting an equitable allocation of already-quantified joint dispatch savings from the already-calculated stand-alone production cost runs.

Q. WHAT AMOUNT OF JOINT DISPATCH SAVINGS HAS STAFF CALCULATED WITH ITS EXISTING PRODUCTION COST RUNS AND HOW HAVE TOTAL JOINT DISPATCH SAVINGS BEEN EFFECTIVELY ASSIGNED OR ALLOCATED TO EACH JDA PARTICIPANT?

A. The table below summarizes joint dispatch savings calculated by Staff, as well as the effective assignment of such savings to AEG and UE that results from the hour-by-hour assignment of transfer energy between entities at the incremental cost of the company producing such transfer energy.

	Assignment of Fuel & PP Expense to Meet Individual Load Requirements Utilizing JDA Transfer Pricing	Results of Staff's Stand-Alone Production Costs Runs	Effective Assignment of Joint Dispatch Savings Pursuant to JDA Transfer Pricing	% of Joint Dispatch Savings Assigned to Participants
UE	$338,778,570	$343,768,083	$4,989,513	13.33%
AEG	$194,177,648	$226,624,693	$32,447,046	86.67%
Total System	$532,956,218	$570,392,777	$37,436,559	100.00%

As evidenced from statistics in the table above, AEG – the smaller of the two participants – is effectively assigned the vast majority of joint dispatch savings. This fact is further borne out when one observes from the table below the percentage reduction in stand-alone costs that each entity achieves under the current JDA transfer pricing procedure:

	Stand-alone Costs	Reduction in Stand-alone Cost as a Result of JDA Assignment of Joint Dispatch Savings	Percent Reduction in Stand-alone Costs Resulting from JDA Assignment of Savings
UE	$343,768,083	$4,989,513	1.45%
AEG	$226,624,693	$32,447,046	14.32%
Total System	$570,392,777	$37,436,559	6.56329%

As highlighted from the above table, it is estimated that the entire jointly dispatched system will achieve a 6.56% reduction from the sum of the two stand-alone systems' costs. However, under the JDA procedures for assigning savings, the UE system achieves only a modest 1.45% reduction in stand-alone costs. In other words, the UE system is only marginally better off than it would be if it had remained a stand-alone system. Unregulated AEG, however, achieves a most significant 14.32% reduction from its calculated stand-alone costs. I believe the two tables above fairly dramatically highlight the inequities in the current JDA. More specifically, the tables demonstrate the inequity that occurs as a result of the JDA pricing that provides that UE – with its lower generating costs – transfer a significant amount of energy "at cost" with no recognition of the foregone opportunity to sell such energy at "market" or "split-the-savings" prices.

Q. WHAT IS YOUR SPECIFIC RECOMMENDATION IN THIS CASE?

A. I am proposing that joint dispatch savings be allocated by applying the overall percentage reduction achieved through joint dispatch to each participants' calculated stand-alone fuel and purchased power costs. More specifically, I am proposing that the overall 6.56% reduction achieved from joint dispatch be applied to each participants' stand-alone costs to arrive at the level of fuel and purchased power costs to be assigned to each participant for cost of service determination purpose. The actual calculations and results of such calculations are shown in the table below:

	UE	AEG	Sum of Stand-alone or Combined System
Stand-alone Fuel & Purchased Power Expense for Load Requirements	$343,768,083	$226,624,693	$570,392,777
Percent Reduction to be Applied to Stand-alone Costs	6.56329%	6.56329%	6.56329%
Reduction in Stand-Alone Cost Proposed for Each Entity	$22,562,513	$14,874,047	$37,436,559
OPC Proposed Reallocation of Fuel & Purchased Power Expense Based Upon Application of Equal % Reduction in Stand-alone Costs	$321,205,571	$211,750,647	$532,956,218
Fuel & Purchased Power Expense Assigned to Participants Utilizing JDA Transfer Pricing (Staff's Current Proposal)	$338,778,570	$194,177,648	$532,956,218
Effective Redistribution of Joint Dispatch Savings Resulting from OPC's Proposed Methodology	$17,572,999	($17,572,999)	$0

I would note that the numbers reflected above for "UE" are "total company UE" amounts. In other words, such amounts should be appropriately allocated to Missouri retail jurisdictional operations utilizing appropriately developed energy allocators.

Q. IS THE ASSIGNMENT OF JOINT DISPATCH SAVINGS BASED UPON CONSIDERATION OF SAVINGS DERIVED FROM STAND-ALONE CALCULATIONS NEW OR UNIQUE?

A. I have not surveyed or researched how various Joint Dispatch Agreements or Interconnection Agreements between jointly owned and dispatched generating companies across the country provide for the assignment or allocation of costs and benefits between participants. I would note, however, that the Interconnection Agreement between jointly owned Kansas Gas and Electric Company ("KGE") and Kansas Power and Light Company ("KPL") provides for calculation of joint dispatch savings to be calculated after-the-fact each month utilizing a production costing model. Under the noted KGE/KPL agreement, the calculated joint dispatch savings are split equally between the two entities. I have affixed to this testimony as Attachment JRD-1 the noted Interconnection Contract between KPL and KGE that provides for the split-the-savings approach for determining fuel and purchased power costs to be assigned to each participating company. I would note as an aside that the KPL/KGE Agreement also considers or includes margins from off-system interchange sales in the after-the-fact savings calculation and assignment of benefits/cost from joint dispatching.

Closer to home, I have reviewed the testimony and exhibits prepared by Dr. Proctor in the recently settled UtiliCorp United, Inc. d/b/a Missouri

Public Service Company proceeding (Case No. ER-2001-672). The Commission will recall that St. Joseph Light and Power was recently acquired by UtiliCorp United, Inc. Furthermore, the Commission will recall that following that acquisition, UtiliCorp United began jointly dispatching the Missouri Public Service and St. Joseph Light and Power divisions. In the noted rate case which followed the St. Joseph acquisition, Staff was proposing the development of a Joint Dispatch Agreement. In that case, Dr. Proctor was advocating that each UtiliCorp-owned Missouri division be allocated total joint dispatch costs in proportion to its share of stand-alone costs. While stated and described from a slightly different perspective than what I have described and explained herein, I believe the upshot of the Staff's proposal in the UtiliCorp rate case is conceptually and algebraically identical to that which I am proposing herein.

Q. YOU HAVE PREPARED A SPECIFIC ADJUSTMENT THAT SHOULD BE INCREMENTALLY POSTED TO THE STAFF'S PROPOSED FUEL AND PURCHASED POWER EXPENSE LEVEL TO BE UTILIZED WITHIN THE DEVELOPMENT OF UE'S MISSOURI RETAIL COST OF SERVICE. IS THE NUMBER CALCULATED SUBJECT TO FUTURE REVISION?

A. Yes. To the extent the Staff reruns its production costing model for any reason, the resulting redistribution of dispatch savings should, likewise, be recalculated. This would true whether the reruns were performed as a result of mistakes identified, procedures improved or merely reflecting different input assumption. As shown above, the calculation redistributing joint dispatch savings is simple and straight forward.

Q. ASSUMING THE COMMISSION AGREES WITH YOUR PROPOSED RATEMAKING METHODOLOGY FOR ASSIGNING COSTS AND BENEFITS FROM JOINT DISPATCH, SHOULD THE COMPANY BE REQUIRED TO ALTER ITS REPORTING OF MISSOURI RETAIL OPERATING RESULTS?

A. Yes. As observed from the numbers shown above, the redistribution of costs being proposed is fairly significant. The change being proposed needs to be reflected within operating results being reported to this Commission, its Staff and the OPC. Accordingly, I would propose that after the Commission determines the cost allocation methodology to be employed for ratemaking purposes in this proceeding that the Staff, the Company and interested parties meet to discuss what kind of record keeping and/or after-the-fact production costing runs could be employed that would facilitate the reporting of expenses and off-system sales margins on a basis consistent with that found reasonable for ratemaking purposes in this proceeding.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS REGARDING THE ASSIGNMENT OF COSTS AND BENEFITS OF JOINTLY DISPATCHING THE AEG AND UE SYSTEMS.

A. Under the current JDA, the vast majority of joint dispatch savings are effectively assigned to AEG to the detriment of UE and its ratepayers. The basic inequity occurs as a result of the JDA provision that specifies the "long" company to transfer energy at the incremental costs incurred to facilitate the transfer or sale. If the "long" energy producing company were permitted to sell its excess energy on the market or at split-the-savings prices that would be fair to both participants to the JDA, a significant redistribution of costs and benefits between participants would occur.

As a result of the inequity observed, I am proposing a reallocation or redistribution of fuel and purchased power expense such that UE and AEG will participate proportionately in savings derived from joint dispatch. The proportionate sharing of joint dispatch savings occurs mathematically by simply applying the total percentage reduction in costs achieved from joint dispatch versus stand-alone dispatch to the stand-alone calculated fuel and purchased power cost of each system.

Finally, whatever cost assignment methodology is employed in this rate setting proceeding should also be employed for UE/Missouri earnings reporting purposes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SECOND SUPPLEMENT
TO
ELECTRIC INTERCONNECTION CONTRACT

KPL-KG&E OPERATING AGREEMENT

This Second Supplement to the Electric Interconnection Contract (Contract) dated July 19, 1962, between The Kansas Power and Light Company, hereinafter called KPL, and Kansas Gas and Electric Company, hereinafter called KG&E, is made and entered into this 19th day of March, 1992, by and between KPL and KG&E. KPL and KG&E collectively are hereinafter called Companies. This Supplement is to be known as the "KPL-KG&E Operating Agreement."

WHEREAS, KPL has received authority to purchase all of KG&E's common stock and to merge KG&E into a KPL subsidiary; and

WHEREAS, KPL and KG&E are the owners and operators of electric generation, transmission, and distribution facilities with which they are engaged in the business of generating, transmitting, and selling electric energy to the general public and to other electric utilities; and

WHEREAS, the Companies can achieve economic benefits through the coordinated operation and central dispatch of the Companies' resources and through a greater level of coordinated maintenance of their electric supply facilities; and

WHEREAS, the Companies desire to establish certain principles under which they plan to jointly operate their two systems; and

WHEREAS, the Companies are each participants in the MOKAN General Participation Agreement which establishes certain minimum planning and operating criteria to be observed by all of its participants; and

WHEREAS, the Companies are each participants in the Southwest Power Pool (SPP) which establishes certain minimum planning and operating criteria to be observed by all of its participants.

NOW THEREFORE, in consideration of the premises and of the mutual covenants and agreements herein, the parties hereto mutually agree as follows:

ARTICLE I - TERM OF AGREEMENT

1.01 This KPL-KG&E Operating Agreement shall become effective at the Effective Time of the Merger, as defined in Section 1.2 of the Agreement and Plan of Merger By and Among The Kansas Power and Light Company, KCA Corporation, and Kansas Gas and Electric Company, or such later date as may be fixed by any required regulatory acceptance. This KPL-KG&E Operating Agreement shall continue in full force and effect until the next May 31 from the effective date hereinabove described, and continue from year to year thereafter until terminated by one of the Companies upon six (6) months written notice to the other Company.

1.02 The MOKAN General Participation Agreement (MOKAN GPA) dated April 19, 1989, and the service schedules attached thereto contain certain definitions and minimum planning and operating criteria to which the Companies subscribe. The MOKAN GPA and its attached service schedules, all as amended from time to time, are therefore incorporated herein by reference and made a part hereof.

ARTICLE II - DEFINITIONS

2.01 Those terms defined within the MOKAN CPA and as given in this Article II shall be used herein. In case of any conflict in definitions, those given in this Article II shall govern.

2.02 Central Power Dispatch Center shall be a center operated by KPL for the optimal utilization of system power resources for the supply of power and energy for the Companies.

2.03 Company shall be either KPL or KG&E.

2.04 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 this KPL-KG&E Operating Agreement is to provide the contractual basis for joint operation of the Companies to achieve optimal economies consistent with reliable electric service and reasonable utilization of natural resources; and to establish the basis for capacity commitments between the Companies.

ARTICLE IV - OPERATIONS

4.01 Planning and Authorization of Production Facilities. For MOKAN Pool planning and equalization purposes, KPL shall coordinate each Company's forecast of System Capacity to meet each Company's System Capacity Responsibility, and its planning Capacity Margin.

4.02 Capacity Margin Requirements. Capacity Margin requirements for each Company shall be in accordance with MOKAN criteria for reserve planning.

4.03 Provision to Achieve Minimum Capacity Margins.

a. Each Company shall own, or have available to it under contract, such generating capability and other facilities as are necessary to supply its System Peak Responsibility plus meet its minimum Capacity Margin requirements.

b. When one Company (committing Company) has sufficient Capacity Balance and the other Company (receiving Company) has insufficient Capacity Balance, a portion of such Capacity Balance can be utilized by the receiving Company by making payments to the committing Company each month of the Year.

c. A committing Company may make available to the receiving Company peaking capacity. The capacity commitment shall be for a twelve-month period or as otherwise mutually agreed.

d. The monthly capacity commitment charge shall be at embedded costs of capacity and transmission delivered to the point of interconnection between the Companies.

e. The energy delivered from the capacity commitment shall be provided under central dispatch and will be considered as part of the energy delivered from one Company to the other for Economic Dispatch.

f. The Companies shall execute and file with the Federal Energy Regulatory Commission an agreement in the form of a service schedule to this KPL-KG&E Operating Agreement for each such commitment of capacity, such agreement to set out all of the pertinent costs, rights, and obligations of the parties relating to the transaction.

4.04 Capacity Sales and Purchases.
KPL shall coordinate the off-system capacity and associated energy sales and purchases as may be required by the Companies to market System Capacity or to meet System Capacity requirements. Any such agreement entered into shall be separately executed by the Company making such off-system sale or purchase.

4.05 Bulk Power Transmission Facilities.
The bulk power transmission facilities which interconnect the Companies' systems and the ownerships are as shown in Exhibit I, attached hereto.

4.06 Economic Dispatch.
The Central Power Dispatch Center shall perform Economic Dispatch by scheduling energy output of the Companies' 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 Exchanges With Non-Affiliated Utilities.
The Central Power Dispatch Center shall coordinate and direct off-system purchases and sales of energy necessary to meet system requirements or to improve system economy in accordance with interconnection arrangements between each Company and non-affiliated utilities.

4.08 Allocation of Costs.
In order to recognize the economic benefits available to both Companies through centralized dispatch, the Companies will "split the savings" achieved. To accomplish this, energy costs for KPL and KG&E resulting from centralized dispatch of the Companies' 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 Company.

b. The "ENPRO" production cost model, developed by Entec Inc., will be used to simulate monthly fuel and interchange energy costs 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 ENPRO model will be established using actual hourly generation values. These operating parameters will then be adjusted, if necessary, until ENPRO's model output statistics for the joint dispatch reflect actual production data (i.e. fuel costs, heat rates, maintenance outages, etc.) for the subject month. Once the model is calibrated to the actual generation parameters, it will be permitted to redispatch the generating resources along with actual interchange transactions that occurred during the month in order to meet the actual hourly load profile of the Companies.

c. The KPL and KG&E systems will then be modeled on an "own load" redispatch 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 redispatch will reflect applicable pre-merger operating practices and conditions.

d. Each Company's incremental or decremental energy cost for the month will be determined as the difference between actual cost (step a above) and the modeled cost (step c above). The difference in the incremental cost for one Company and the decremental cost for the other Company shall represent the cost savings achieved through centralized dispatch. Each Company's stand alone costs (step c above) will then be reduced by one-half of the cost savings. The result will be the adjusted energy cost for the month for each Company.

e. The Companies shall reconcile energy costs each month. The Company which incurred additional costs during the month for the benefit of the other Company shall receive from the benefitting Company a payment equal to the difference between the costs incurred for the month (step a above) and the adjusted energy cost (step d above).

Exhibit II, attached hereto, is an illustrative example showing energy costs, centralized dispatch savings and the split of the savings between KPL and KG&E for a hypothetical month.

4.09 Transmission Losses.
Transmission losses occasioned by the transfer of power and energy between the Companies resulting from Economic Dispatch will be paid for in accordance with the supplying Company's most recently accepted rate under the Federal Energy Regulatory Commission's regulations at 18 C.F.R. 35.23, or such further regulations as may be issued and made effective.

4.10 Communications and Other Facilities.
The Companies 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. For such other purposes as may be necessary for optimum operation of the system.

ARTICLE V - CENTRAL POWER DISPATCH CENTER

5.01 Central Power Dispatch Center.
KPL shall provide and operate a Central Power Dispatch Center adequately equipped and staffed to meet the requirements of the Companies for efficient, economical, and reliable operation as contemplated by this KPL-KG&E Operating Agreement.

ARTICLE VI - GENERAL

6.01 Regulatory Authorization.
This KPL-KG&E Operating Agreement is subject to regulatory approvals by the Federal Energy Regulatory Commission and each Company shall diligently seek all necessary regulatory authorization for this KPL-KG&E Operating Agreement.

6.02 Effect on Other Agreements.
This KPL-KG&E Operating Agreement shall not modify the obligations of either Company under any agreement between that Company and others not parties to this KPL-KG&E Operating Agreement or other agreements in effect at the date of this KPL-KG&E Operating Agreement.

IN WITNESS WHEREOF, each of the Companies has caused this KPL-KG&E Operating Agreement to be signed in its name and on its behalf by its Chief Executive Officer and attested by its Secretary, both being duly authorized.

ATTEST:

Asst. Secretary

(Seal)

THE KANSAS POWER AND LIGHT COMPANY
By: William E. Brown
William E. Brown
President and Chief Executive Officer
KPL - Division

ATTEST:

Secretary

(Seal)

KANSAS GAS AND ELECTRIC COMPANY
By: James S. Haines
James S. Haines
Group Vice President

EXHIBIT I

TO THE
SECOND SUPPLEMENT
TO
ELECTRIC INTERCONNECTION CONTRACT

BULK POWER TRANSMISSION INTERCONNECTIONS

The bulk power transmission interconnections between the KPL and KG&E systems are:

a. Wichita-Lang 345 KV transmission line.
345 KV line extending from KG&E's Wichita 345 KV substation near its Gordon Evans Steam Electric Station to KPL's Lang Substation located northeast of Emporia. The actual point of interconnection is at a point approximately two and one-half (2 1/2) miles east and one-half (1/2) mile south of Matfield Green, Kansas.

b. Midian-Tecumseh 161 KV transmission line.
161 KV line extending from KG&E's Midian Substation near El Dorado to KPL's Tecumseh Substation located east of Topeka. The actual point of interconnection is approximately 23.77 miles southwesterly from KPL's Tecumseh Hill Substation, Tecumseh, Kansas.

c. Moundridge 138/115 KV Substation.
KPL's 138/115 KV transformer located in KG&E's Moundridge Substation near Moundridge, Kansas. The actual point of interconnection is on the 138 KV side of the transformer.

EXHIBIT II

TO THE
SECOND SUPPLEMENT
TO
ELECTRIC INTERCONNECTION CONTRACT

EXAMPLE COST ALLOCATION

			Amount (000's)
1.	Record actual fuel and net interchange costs for the month.	KPL KG&E	$ 9,000 9,500 $18,500
2.	Production model the joint control area operation to reflect actual operating parameters and costs.		$18,500
3.	Production model the two separate control areas on a stand alone basis using model data determined in Step 2 above.	KPL KG&E	$10,500 8,500 $19,000
4.	Determine KPL's decremental cost for the month.		$10,500 9,000 $ 1,500
5.	Determine KG&E' incremental cost for the month.		$ 9,500 8,500 $ 1,000
6.	Establish the centralized dispatch savings for the month. (Item 4 minus item 5.)		$ 500
7.	Savings available to reduce each Companies' stand alone costs. (One half of item 6.)		$ 250
8.	Adjusted fuel and net interchange costs for the month.	KPL KG&E	$10,250 8,250 $18,500

Note: Amounts shown are for illustrative purposes only. In this example month, KPL would pay KG&E $1,250 which is the difference between $10,250 and $9,000.