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Case No.: EM-2000-369
Date Prepared: June 19, 2000

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**

REBUTTAL TESTIMONY OF

WHITFIELD A. RUSSELL

On Behalf Of
Springfield (MO) City Utilities

June 19, 2000

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Date 9-15-00 Case No. EM-2000-369
Reporter KF

Before the Public Service Commission
Of the
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UtiliCorp United Inc. and The Empire District	)	
Electric Company for Authority to Merge	)	
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WHITFIELD A. RUSSELL

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INTRODUCTION

Q. What is your name, affiliation and business address?

A. My name is Whitfield A. Russell. I am a public utility consultant and president of Whitfield A. Russell and Associates, P.C., located at 1225 Eye Street, N.W., Suite 850, Washington, D.C. 20005. The P.C. is a corporate partner of Whitfield Russell Associates.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Springfield (MO) City Utilities ("Springfield" or "City Utilities").

Q. Please summarize your qualifications.

A. I hold a Bachelor of Science degree in Electrical Engineering from the University of Maine, a Master of Science degree in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center. My complete resume and a description of proceedings in which I have testified are attached hereto as Schedule No._(WAR-1).

Q. What is the purpose of your testimony?

A. My general purpose is to explain why the proposed merger of The Empire District Electric Company ("Empire", "EMDE", or "EDE") into UtiliCorp United Inc. ("UtiliCorp" or "UCU") is detrimental to the public interest. The proposed merger, especially when viewed in combination with the proposed related merger of St. Joseph Light and Power Company ("St. Joseph L&P"or "SJLP") into UtiliCorp, threatens the public interest in ways the Applicants have failed to disclose fully to the Commission. As I will discuss, the proposed merger could have adverse effects on both retail rates and reliability. The merger is likely to prompt Applicants to construct transmission that is penny wise (for Applicants) but pound foolish for the rest of the State of Missouri. Conspicuously absent from the merger application, however, is any commitment to construct transmission needed to ensure a robust and reliable grid. Nor have Applicants evaluated fully the impacts of the post-merger flows on the grid, leaving this Commission and intervenors in the dark on issues crucial to evaluating whether the proposed merger is in the public interest.

As I describe below, it is clear that the merger will give Applicants new rights over use of transmission that could be used to restrict availability of transmission to others and undermine competition in the wholesale power markets. Nothing in the Application prevents them from using these new rights anti-competitively. This suppression of wholesale competition arises from the merger and can be expected to increase rates to Missouri retail ratepayers, including those of Springfield. In addition, Springfield is concerned that the merger could adversely affect firm deliveries of Springfield's purchase of firm unit power from the Montrose generating station of Kansas City Power & Light ("KCPL").

Our studies indicate that the Missouri Public Service ("MoPub" or "MPS", a division of UtiliCorp) transmission system is weak and unreliable as measured by prevailing engineering standards and might be even more unreliable after UtiliCorp integrates the operation of its currently separate control areas in Missouri.[1] This has significant consequences to the State of Missouri. Under a literal interpretation of industry curtailment rules, MoPub – as a part of the merged company - could arguably call for transmission loading relief ("TLR") when it experiences transmission overloads and thereby halt north-to-south transfers needed by other Missouri utilities in order to lower their costs. In some cases, UtiliCorp would have an incentive to call for TLRs even in the absence of line outages or other contingencies.

[1] In engineering terms, our studies show that criteria violations can be expected on the UtiliCorp transmission system under conditions predicted to occur at peak (base case) in both the Summer 2000 and the Summer 2001.

I. Why Should the Missouri PSC Take An Active Role in Transmission?

Q. Why should the Missouri Commission involve itself in issues related to transmission?

A. Transmission is at the core of ensuring the reliable and economical electricity service that is in turn at the core of the regulatory mission of this Commission. Transmission construction (or lack of construction) and restrictions on transmission availability have direct rate impacts upon Missouri retail customers.

Failure to construct facilities needed to support post-merger operations can result in a degradation of service to all Missouri ratepayers. In the UtiliCorp and Empire District merger, Applicants have set out a plan to build a 161 kV line from Nevada (UtiliCorp) to Asbury (Empire) in the year 2003. That line parallels a 161 kV line from Stockton to Morgan owned by Associated Electric Cooperative and known to limit north-south flows. See the 1999 SPP FERC Form 715, Part 6, page 9. But Applicants have not committed to build the Nevada-Asbury line.

In addition, as part of the related merger between UtiliCorp and SJLP, Applicants set out a plan (but not a commitment to build) the Lake Road to Nashua 161 kV transmission line, but that line does not meaningfully add to the transfer capability or stability of the grid. The new line will create a contract path that will enable Applicants to avoid supporting the Kansas City Power and Light transmission system, through which much of the power nominally using the new line may nevertheless flow. UtiliCorp ratepayers will bear the costs associated with constructing and operating the line if it is built.

Curtailments and interruptions that result from over-extending the transmission system are of palpable interest to Missouri retail customers. Ensuring that adequate transmission is constructed to provide reliable service to all Missouri ratepayers requires study and advance planning, not the "approve the merger first, figure out how we'll operate later" approach Applicants appear to be taking.

In addition, restrictions on transmission availability as a result of the merger can adversely affect the wholesale market. Obviously, adverse effects experienced in wholesale markets are experienced by retail users as well.

Q: Why should the Missouri commission be concerned about competitive power markets?

A. Missouri retail customers benefit from a robust wholesale power market. A robust wholesale market operates to minimize the costs that Missouri utilities pass on to their retail customers through their rates. For example, wholesale purchase opportunities can lessen or eliminate the need for higher-cost generation additions. Similarly, wholesale sales ordinarily produce revenue credits in retail rate cases, minimizing the portion of the revenue requirement that must be recovered from retail customers. And vigorous wholesale competition is also a necessary predicate to the retail competition this State may consider in the future. That is, retail access can be expected to produce few benefits when retail customers are confronted with unduly concentrated wholesale markets.

Q. But isn't wholesale competition and transmission the job of the Federal Energy Regulatory Commission ("FERC")?

A. Yes. FERC is the agency with jurisdiction over the rates, terms and conditions of transmission service in interstate commerce and wholesale sales by investor-owned utilities. Nevertheless, in ensuring that a proposed merger is in the public interest, the Missouri Commission should insist that the merger be structured to ensure that Missouri retail customers obtain the benefits of a safe and reliable transmission system and robust competition at wholesale.

Open access to transmission facilities is essential to promoting that competition. Without open access, vertically integrated transmission owners can use their ownership and control over transmission to favor their generation sales and to keep out competitors. Therefore, preserving and fostering open access to transmission is vital to the interests of the States irrespective of whether FERC has jurisdiction over the rates, terms and conditions of that transmission.

In addition and significantly, it is the State, and not FERC, that has the authority regarding certification of transmission facilities, ensuring the adequacy of the transmission system and setting retail rates to recover transmission costs. Thus, Missouri has a clear interest in ensuring that utilities are not permitted to structure themselves through merger to place undue burdens on the transmission system, spurring construction of unnecessary and inefficient lines, or failing to commit to construction of truly needed transmission.

Q. You mentioned that utilities can abuse their control over transmission in order to favor their sales of generation. Is there any evidence in Applicants' filing that they are seeking to exploit their control over transmission?

A. Yes. Applicants' Schedule RCK-10 (Schedule _ WAR- 5) is a study examining options for physically connecting UtiliCorp to EDE, and that study evidences Applicants' preference for a plan that is penny wise for Applicants and pound foolish for the remainder of the region.

Q. Please explain.

A. First, it appears that, UtiliCorp has determined that its least expensive option for integrating the operations of UtiliCorp and EDE, is to build transmission facilities to interconnect physically these two transmission systems. The evidence seems to show that although these new facilities may be the least costly integration option for UtiliCorp, this approach will impose substantial costs on other users of the regional transmission system. This is because transactions among the merging companies exacerbated later by integration will, as a practical and physical matter, depend on the transmission facilities of others, even if UtiliCorp constructs the new interconnection with EDE. Yet, UtiliCorp evidently takes the position that need not bear responsibility for these adverse third-party effects of its merger.

Ironically, Applicants initially sought to rely exclusively upon transmission systems of their neighbors in order to integrate their systems, and seemed to have accepted responsibility for such third-party effects. In pursuit of that strategy, they applied to the Southwest Power Pool ("SPP") ISO for network transmission service. In a data response filed in the related merger involving UtiliCorp with St. Joseph L&P, Applicants seemingly committed to make any upgrades and system improvements that were found necessary in the SPP System Impact Study. But, when the April 21, 2000, SPP System Impact Study indicated that substantial facility upgrades and system improvements would be required to accommodate Applicants' request, Applicants withdrew their application for SPP network service. They substituted in its place instead a vague, non-binding commitment to interconnect first and then later place their transmission facilities under either the Midwest ISO or the SPP transmission tariffs. Applicants contend that if they elect to build direct interconnections under their new proposal, "network service would no longer be required in order to permit those systems to be joined into a single control area." See Supplemental Testimony of Richard C. Kreul in FERC Docket Nos. EC00-27-00 and EC00-28-00 at 4 filed May 19, 2000. Schedule__ WAR- 8.

The study provided by Applicants in Schedule RCK-10, based on the system of the Southwest Power Pool in the year 2003, analyzes four options for interconnecting the merging companies. Three of them are based on physically interconnecting the two systems through the proposed 161 kV Nevada-Asbury line, a new 161 kV Sedalia to Burns line, or through the two 69 kV interconnections. The fourth option is contractual, based upon purchasing transmission capacity from either KCPL or Western Resources. The recommended option - the 161 kV Nevada-Asbury line - relieves existing constraints and voltage problems in the Nevada area. However, it appears from the SPP System Impact Study that **none of these three physical interconnecting options is likely to** alleviate all problems in the broader region affected by Applicants' plan to integrate their operations.

Q. What actions can State Commissions take with respect to transmission and distribution?

A. State commissions have an important role to play in a number of areas:

1. I understand that in Missouri, the Commission has the authority to issue permits on transmission facilities built outside certificated service areas, or to certificate the construction of new transmission facilities. It appears that the Commission is being asked to approve one such facility as part of this merger (at least tacitly). That is, Applicants' preferred transmission alternative (Option 1, the Nevada South to Asbury 161 kV line described at page 4 of Mr. Kreul's Schedule RCK-10) would be a new line routed from UCU to EDE.
2. Transmission owners must obtain authorization from a State in a rate case in order to recover the cost of new transmission facilities in that State. It is therefore

important – as a prelude to judging the prudence of new transmission facilities, that States understand and participate in the transmission planning process. Through such participation, States can better exercise their jurisdiction in order to eliminate load pockets and to relieve transmission constraints that cause price spikes. It appears that the Staff of the Missouri Public Service Commission ("MPSC") and the Commission itself are deeply involved in the planning processes of utilities, Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs").

3. In Order No. 888, FERC delegated to the States the right to establish the dividing line between transmission facilities and distribution facilities by use of the so-called "seven factors test". The manner in which States carry out this mandate can greatly affect competition and access to delivery services. States should implement the seven factors test in ways that foster competition.

4. Even when utilities restructure and offer retail access, States define what are distribution facilities and specify the terms under which retail transmission customers obtain access to distribution facilities. These activities can greatly affect wholesale transmission rates and the effectiveness of competition.[2]

Q. In your experience, does FERC defer to State wishes with respect to transmission access?

[2] These activities are of particular importance to retail customers that have the ability to curtail load (and thereby render ancillary services) or that possess inside-the-fence self-generation, especially if those entities seek to sell ancillary services or power into wholesale markets. An overbroad definition of distribution facilities can impose "pancaked" losses and delivery charges on inside-the-fence generators and place them at a disadvantage in competing for wholesale sales. Pancaked losses and delivery charges can be major impediments to marketers and wholesale customers seeking to buy power or services from interruptible industrial users and inside-the-fence generators.

A. For the most part, yes. FERC has repeatedly deferred to state commissions with respect to transmission planning, implementation of open access transmission tariffs (especially as such tariffs are applied to bundled retail sales), formation of ISOs and separation of the transmission function from the distribution function ("refunctionalization"). For example, FERC has recently approved transfers of transmission facilities pursuant to Wisconsin legislation that encourages utilities to transfer ownership of their transmission facilities to a jointly-owned "Transco" that will be a separate zone within the Midwest ISO. That legislation also encourages utilities to transfer control over their transmission facilities to the Midwest ISO.

Q. How could the Missouri Commission foster competition and ensure reliable service at reasonable rates in the exercise of its jurisdiction over mergers?

A. The Commission could deny a merger or impose conditions upon its approval of a merger. I recommend several such conditions in later sections of my testimony.

II. Native Load Priorities

Q. What is Springfield's first concern with the proposed UCU/EDE merger?

A. Springfield's first concern is that the merged companies can invoke native load priority and possibly place Springfield at a severe economic disadvantage in obtaining low-cost power and in obtaining transmission service for both off-system bulk power purchases and sales. Non-discriminatory access to transmission service is taking on more importance to entities such as Springfield that depend on access to transmission. As I noted earlier, Springfield is principally interested in protecting deliveries of its planned imports of firm power but is also interested in protecting its imports of non-firm energy from being excessively curtailed.

Q. What are native load priorities?

A. Native load priorities are rights that may be possessed by a vertically integrated utility transmission owner under contract, State law and court precedents that protect transmission service to "native load" – i.e., a utility's bundled retail customers. Transmission owners can invoke native load priorities in order to favor deliveries of their own purchases and sales of generation and to obtain favored access for their native loads through transmission bottlenecks.

By virtue of the mergers of UtiliCorp with EDE and SJLP, Applicants will be able to exercise their native load priorities and expand the coverage of those priorities to cover deliveries between Applicants' native loads in what are now three separate Missouri control areas, even if all of those control areas are not integrated operationally or not physically interconnected by Applicants' own transmission lines. By these means, Applicants will be able to import their own firm resources through constrained interfaces while potentially curtailing Springfield's firm purchase of unit power from the Montrose generating resource of KCPL. Similarly, Applicants may be able to assert a higher priority for their imports of non-firm energy over Springfield's use of non-firm point-to-point transmission service if Springfield does not take network service. Springfield recognizes that UtiliCorp has offered to protect competing entities within its system from its exercise of the native load priority to import non-firm energy (the so-called "AES/TVA" priority). But Springfield is not within the Applicants' system and seeks more specific protections, particularly against the merged company's use of native load priority to free up local resources that enable it to make off-system sales through displacement.

For example, Applicants might move power from one of their operating companies into another operating company, asserting a native load priority and "reducing" the generation in the receiving operating company. However, simultaneously, they could initiate an off-system sale from generation located in the second, receiving operating company. This would in effect allow the Applicants – under the guise of meeting a native load requirement - to exploit their native load priority and move generation through a bottleneck for a distinctly non-native load purpose: making off-system sales. Thus, the various operating companies of the Applicants could be used as "staging platforms" from which Applicants gain access to remote markets uninhibited by transmission constraints that are imposed upon others.

PROPOSED CONDITIONS

Q. What conditions should be placed on the merger in order to protect Springfield against Applicants' anti-competitive invocation of native load priorities?

A. In general, I recommend conditions that prevent Applicants from expanding their use of existing native load priorities beyond their present geographic scope. More specifically, Applicants should be required to commit that with respect to any and all generating resources associated with any one of their existing control areas (including purchased generating resources) serving load in any other control area of the merging companies, the merging companies should waive or not assert:

a. Native load priority on scheduling non-firm network transmission service. This merely confirms the Applicants' offer to waive their priorities under AES/TVA without limiting the protected class to transmission dependent utilities located within Applicants' service territory, which is the narrower protection offered by Applicants.

b. The native load preference arguably accorded to bundled retail loads over wholesale loads under the decision in Northern States Power Co. v. FERC, 176 F.3d 1090 (8^{th} Cir. 1999) and

c. Use of any native load priority that will enable any one of the merging companies to import power through constrained interfaces so as to free up its local generating resources for off-system sales.

III. Internal Dispatch.

Q. What is Springfield's second concern?

A. Springfield is concerned that joint operation of the merged companies (internal dispatch) might subject the region to unanticipated swings in power flows as the Applicants re-dispatch their units. Internal dispatch will exacerbate any overloads caused by Applicant's exercise of their native load priorities. These power swings might result in the imposition of additional curtailments on other utilities in real-time, shifts in losses and loss burdens, re-dispatch, congestion costs and other adverse impacts. Such impacts would not necessarily be captured in analyses of market power or in planning studies that are conducted in order to analyze the impacts of the merger upon the use of the regional transmission network. Indeed, it is clear from our discussion with UtiliCorp's analysts that transmission constraints presently limit their integration of their control areas and that no study has addressed these potentially adverse consequences of the merger.

This concern has arisen in conjunction with other mergers. It is usually addressed by simulating internal dispatch through multi-area production cost studies that determine on an hourly basis the amount of power that has to flow from one of the merging control areas to each other control area in order to optimize economic dispatch. Although not a perfect tool, this type of analysis provides important insights with respect to the magnitude, direction and duration of power flows (and transmission capacity) needed to accommodate internal dispatch between isolated pockets of load and generation that are newly operated under a single economic dispatch algorithm. For example, the analysis might show that the peak flows between the isolated pockets resulting from unconstrained economic dispatch will occur for only a few hours per year and produce few economic benefits. In such a case, it would be better for the State of Missouri (and perhaps for the merging company as well) for Applicants to constrain their economic dispatch. They could agree to limit their internal dispatch flows to a specific ceiling amount, leaving the remainder of the interconnecting transmission capacity available for sale as long term firm transmission service for transactions that produce greater benefits.

A related concern is that industry rules exempt Applicants' internal dispatch from the capacity posting, reservation, scheduling and monitoring requirements (Open Access Same-Time Information System – "OASIS") of their Open Access Transmission Tariff and from the similar requirements of any regional transmission provider. This could pose a problem for Springfield to the extent that the merged company consolidates its separate control areas into one. Consolidation of control areas would transform what are now (a) pre-scheduled and readily curtailable resale transactions that are reported on the OASIS of each affected transmission owner into (b) "internal dispatch" between affiliated utility companies that is exempt from the usual rules regarding reservation, scheduling, reporting, monitoring, and tagging and is therefore at least in practice less subject to curtailment of transmission service. This exemption would be in effect regardless of whether the transactions between affiliates of the merged company might actually flow as circulating loop flow[3] over the transmission systems and control areas of utilities that operate in parallel. The transmission capacity needed to carry out these flows would be exempt from disclosure even in those instances in which those flows commandeer what would otherwise be Available Transmission Capacity ("ATC") on the relevant regional interfaces. And there would be no requirement that such flows be pre-scheduled. Unless special analyses are conducted beforehand and special monitoring is added, one cannot easily predict the magnitude, direction and duration of internal dispatch flows and cannot determine the magnitudes of internal dispatch flows in real time. As a result, a large buffer or cushion of transmission capacity must be left unloaded in order to accommodate these unpredictable and unknown flows. Ordinarily, transmission capacity that is not being utilized must be disclosed and made available to other users when not being utilized by the owners. But in the situation posed by the two UtiliCorp mergers, transmission capacity that is temporarily unused by internal dispatch can be sold on a non-firm basis but cannot be put to its highest and best use, moving power on a firm basis for a long term. Thus, the ATC in the region might be "soaked up" with a resulting loss in economic efficiency to the region.

In summary, Springfield is concerned that internal dispatch of the merged company that is unpredictable as to magnitude, direction and duration will "soak up" ATC without warning to other transmission users. Springfield is also concerned that internal dispatch will ordinarily be exempted from the pre-scheduling requirements of the OATT and not

[3] Loop flow is power that flows over transmission lines, not as a result of scheduled transactions over the lines but in response to the laws of physics (i.e. the path having the lowest impedance). Such flows reduce the available transfer capability of the lines preventing other potential users from obtaining transmission service.

be reported on the OASIS of the transmission owner or of any ISO or RTO in which it participates, and will therefore be effectively shielded from curtailments while enhancing the potential for curtailment of others. Unless internal dispatch is studied in advance and monitored and constrained in real time, ATC will be needlessly reduced. This needless loss of ATC will harm other Missouri utilities, power marketers and their customers.

Q. What does Springfield suggest as a remedy for these concerns?

A. Springfield recommends that the Commission impose conditions on the merger such that:

a. Applicants not be allowed to combine any or all of their existing control areas without first submitting their plans for such combinations to peer group review and approval by the SPP ISO/RTO and the affected regional reliability councils.

b. The merged companies be required (i) to reserve transmission capacity on the relevant OASIS for purposes of carrying out any internal dispatch between what are now geographically separate control areas of the merging companies, (ii) to implement real-time monitoring of intra-company flows associated with internal dispatch, (iii) to report continuously the amount of such flows on its OASIS and (iv) to make all reasonable efforts to limit internal dispatch to levels at or below the transmission capacity reserved for purposes of carrying out such internal dispatch. This will serve to maintain the status quo ante.

c. If the burdens on Springfield attributable to internal dispatch of Applicants turn out to be substantial (i.e., a substantial increase in curtailments of Springfield's firm schedules from Montrose), the merged company should be required to reimburse Springfield for the incremental costs to Springfield of re-dispatching Springfield's generating resources that are attributable to the post-merger integrated operations of Applicants' separate systems.

Q. Have Applicants addressed the effect of internal dispatch on regional ATC?

A. Belatedly, indirectly and ineffectively, yes. At pages 4-5 of his May 19, 2000, Supplemental Testimony at FERC (Schedule _ WAR-8), Mr. Kreul offers to limit transfers but only "under normal operating conditions" for three years after Applicants complete their integration. The limits will be 200 MW from MPS to each of Empire and St. Joseph and 100 MW from each of Empire and St. Joseph back to MPS. He indicates that this level of transfers will enable Applicants to achieve the "energy cost savings which are one of the benefits resulting from the integration of the power supply functions of the Applicants." However, he has not analyzed the associated loop flows on other utility systems "resulting from the integration of the power supply functions of the Applicants." Nor has he quantified any offsetting losses likely to be borne by other regional utilities and their customers whose transactions must be curtailed to accommodate such loop flows or whose transmission systems must be reinforced in order to carry those loop flows. Dr. Frankena assumes that these transfers will be given priority treatment. Supplemental Testimony of Mark W. Frankena at p.5, line 20- p. 6, line 1. (Schedule __ WAR-8). Mr. Kreul does not indicate, however, whether Applicants will agree to pre-schedule their internal dispatch on their OASIS, monitor that internal dispatch in real time, or notify others in real time of the amount of their internal dispatch. And, importantly, Mr. Kreul reserves to the Applicants the right to exceed these self-imposed limits "due to redispatch or other system requirements, which would be determined by the applicable regional transmission system operator". In view of the many contingencies and uncertainties preventing Applicants from "making an immediate decision regarding whether to place [their] future integrated systems ... under the SPP or Midwest ISO" (Kreul FERC testimony at 5-8), the "applicable regional transmission system operator" will presumably be Applicants themselves.

IV. SPP ISO/RTO

Q. What is your third concern?

A. Springfield is concerned that the merged company will not operate as part of a single ISO or RTO. Although Applicants seem keen to integrate the generation of their affiliated companies (and garner the economic benefits of doing so), they are somewhat cavalier about integrating their transmission facilities with those of non-affiliates. In gauging the effect on Missouri's public interest, the integration of transmission facilities under a regional transmission organization is far more important than integration of Applicants' generation because an RTO will identify and protect against potential abuses likely to flow from Applicants' plan to integrate their generation. Mr. Kreul's testimony (in Docket EM-2000-369 at 9, 12 and 13) is coy on this subject, indicating that Applicants cannot yet decide on what ISO to join or how to integrate their open access transmission tariffs. Each of these issues can be decided now and should be decided in order for the Commission to assess whether the merger is in the public interest.

Applicants are considering membership in two different ISOs (SPP and Midwest). Empire is currently in SPP. St. Joseph L&P currently operates as part of Mid Continent Area Power Pool ("MAPP"). I understand that UtiliCorp currently takes service under a MAPP transmission tariff and has, within the past few years, withdrawn the transmission facilities of Missouri Public Service from the control of the SPP ISO/RTO.

Q. Why is RTO/ISO membership important?

A. Control over transmission and distribution facilities has all too often been exercised in anti-competitive ways. One classic example of this anti-competitive behavior occurs when an owner of vertically integrated transmission and generation facilities denies competing generators access to its transmission and/or distribution facilities. The only effective antidote to this behavior is to separate the ownership and control of transmission from the ownership and control of generation through transfer to an ISO or RTO. FERC has ordered a less strict separation of transmission from generation through the functional unbundling required by Order No. 888.[4] However, utilities employ many subtle

[4] FERC has ordered partial divestiture of generation in some cases.

strategems (and some not so subtle) in order to frustrate the separation of functions and to deny transmission access.

Although FERC's Order No. 2000 recognizes FERC's own authority to require RTO participation in certain circumstances, FERC is seeking to promote voluntary RTO formation (both through that order and more generally). This Commission should be concerned about the manner in which Missouri utilities carve up the state into multiple RTOs that may enhance individual utilities' marketing advantages, rather than supporting a vigorously competitive regional market. Applicants, by being cagy as to their RTO plans, leave the state vulnerable.

Q. What do you recommend as a remedy for this concern?

A. I recommend that the merged company put all of its transmission facilities in Missouri and Kansas under the control of the SPP ISO/RTO in a single zone under the SPP transmission tariff and that the merged company join - and maintain membership in - the SPP ISO/RTO. KCPL, Springfield, and Empire are in the SPP ISO, and although UtiliCorp has canceled its previously requested network service from the SPP ISO, the mere fact of its application for such service demonstrates the suitability of SPP participation by the merged company. Thus, while the Midwest ISO is arguably feasible, it would be more logical to condition merger approval upon the Applicants' joining the SPP ISO/RTO. And any additional benefits of participation in the Midwest ISO may ultimately be realized through a merger of the Midwest and SPP ISOs which is still a viable option.

Moreover, I recommend that the Missouri Commission order Applicants to file an integrated OATT and an integrated transmission rate for their control areas in Missouri.

V. **Absence Of Necessary Studies**

Q. What is your next concern?

A. Applicants have not analyzed the impact of their combined uses of the region's transmission system upon transmission customers such as Springfield. Instead, Applicants conducted a series of limited studies in which they considered only what new transmission projects would be needed in order to accommodate joint operation of the merging systems through physical interconnection between Applicants' systems. In these studies, Applicants assumed that additional transmission facilities were going to be constructed, and then modeled the resulting power flows assuming that the constructed facilities were in place. No transfers between Applicants' systems, such as transfers to achieve the proposed energy cost savings, were incorporated in these load flow studies.

Applicants initially made it clear that they had not committed to construct any of the incremental facilities they modeled. They asserted that the studies were conducted only as a means of obtaining a conservative estimate of the benefits of merged operations (in terms of their perception of minimizing the estimated merged system benefits). Moreover, Applicants had reserved the right to forgo construction of any new facilities and to rely instead upon utilization of the regional transmission system, either through network transmission services or point-to-point transmission service. See the testimony of Richard Kreul , at Docket No. EM-2000-369 page 11, line 4-page 12, line 23.

In summary, Applicants appear not to have conducted studies necessary to indicate the likely impacts of their planned uses of the regional system upon other transmission users. In response to Springfield's data requests on the scope of their studies, Applicants indicated:

1. That such a study would be conducted by SPP,
2. That such a study had not then been conducted,
3. That the SPP study would take two to three months to complete and
4. That the planned SPP study resulted from Applicants' filing an application seeking SPP network service.

See UtiliCorp's response to Springfield's data request No. EDSPR-24. Schedule _ (WAR-2). UtiliCorp revised that application on January 27, 2000. Schedule__(WAR-2). As I noted earlier, SPP did conduct a System Impact Study dated April 21, 2000, although I did not see that study until well after that date.

Q. Is the SPP study sufficient to protect Springfield and other transmission users?

A. Perhaps the SPP study would have been sufficient if Applicants had agreed to accept its findings and to make the recommended upgrades, but that is apparently not to be the case. As I noted, the SPP System Impact Study addressed the network transmission service requests from UtiliCorp, EDE, and SJLP (Schedule__WAR-7). It was finalized in April and released at the end of May. The study determined that the requested transmission service will cause numerous thermal overloads and voltage problems and that facility upgrades and system improvements are required in order to accommodate the requested service. Faced with these results, Applicants withdrew their request for network service from SPP. Because Applicants have not shown a willingness to pay for the system upgrades identified by SPP, we have no assurance that the necessary protection will be provided to other transmission system users.

Q. Please describe the SPP study results in more detail.

A. SPP evaluated the impact of rendering network transmission service to UtiliCorp, EDE, and SJPL for ten years. The years selected for study were 2000, 2001, 2004, 2006, and 2010. The study analyzed system conditions for 2000 Fall Peak, 2001 Winter Peak, April Peak, Spring Peak, Summer Peak, and Fall Peak, 2004 Winter and Summer Peak, 2006 Winter and Summer Peak, and 2010 Summer Peak. SPP simulated single outages and selected multiple branch outages.

Regarding transfers between Applicants, SPP studied two system conditions: one based on the existing system and a second based on additional transfers between UtiliCorp, EDE, and SJLP. Additional transfers between Applicants' systems were limited to 100-200 MW.

In the Executive Summary of the Impact Study (Schedule__WAR-7, page 3, paragraph 2), SPP reported that "UtiliCorp and SPP Criteria were used to determine what violations exist." SPP also reported (page 4, paragraph 1) that it analyzed whether "current SPP Criteria and NERC Planning Standards were fulfilled". It remains unclear whether UtiliCorp criteria are in compliance with the SPP criteria. This topic is discussed later in my testimony.

The Study reports a substantial number of overloaded lines and voltage problems. For example, in the 2000 Fall case in which the system experiences relatively low load levels, overloading on the 69 kV line Sibley to Liberty (UCU) is caused by an outage of the 161/69 kV transformer at Sibley. In the Winter 2000/01 case, several contingencies overload the 69/34.5 kV transformer at Fairplay 217 substation in EDE. Contingency analysis of the summer peak 2001 case reveals twenty-eight overloaded facilities in the UtiliCorp area and one in the EDE area (Schedule__WAR-7, Page 7). Numerous voltage problems are reported, with especially low voltage reported in the EDE area. See pages 20-63.

SPP reviewed all potential violations with the owners of the affected transmission facilities and noted how the overloads might be alleviated. Some of the proposed resolutions for the problems identified are: "provide solution", "reduce generation", "line rebuilt", "acceptable", "accept risk", "reconductor", "upgrade", and "increase capacity rating". However, whatever actions utilities selected to eliminate the overloads, the SPP report clearly indicates that problems exist.

Faced with these results, Applicants withdrew their network service request, as noted earlier. They now have indicated to FERC that they are considering the remaining option: physical interconnection between UtiliCorp and EDE. The preferred option (but an option to which Applicants have still not made a firm commitment) is a new 161 kV line from Nevada to Asbury. According to Schedule RCK-10 (Page 4 of 11, under C), this line is projected to be in service by the Summer of 2003. However, the SPP study indicates that problems exist in the Fall of 2000 and that problems continue to crop up through the Winter of 2000, Summer of 2001, and so on. Moreover, Applicants' studies analyzing options for physical interconnections did not analyze the impact on regional transmission of integrated operation of Applicants' systems in a single control area. Therefore, a study is needed that simulates the combined operations of Applicants' systems with the specific upgrades now under consideration, particularly for the period before the Summer of 2003 when those upgrades are projected to be in place, a period in which the SPP System Impact Study identified substantial problems.

Q. What do you recommend as a remedy for the lack of necessary studies upon which the Applicants are willing to commit themselves to pay for the indicated system upgrades?

A. I recommend that Applicants be ordered to conduct production cost, load flow and stability studies of the effects upon other utilities of combining Applicants' electric systems (and of combining their control areas). Flows between Applicants' separate control areas can be determined from hourly production cost simulations. These studies should be done in the next month and be provided to Springfield and other affected transmission customers. The studies should be provided in hard copy in summary form and completely in electronic form in a format that allows all parties to replicate and run the studies on their own software. Given the importance of these studies to the issues at hand, I further recommend that the Commission keep the case open until such time as the studies have been completed and all parties have been allowed sufficient time to review and comment upon such studies. I would ask the Commission to allow a thirty-day period after the completion of the studies to allow parties to file their comments. If, after the comments are filed, the Commission determines that additional hearings are warranted, hearings could be continued at that time.

Such studies should include – but not be limited to:

a. Production cost simulations that indicate the hourly amount of power flow that can be expected to occur between each of the separate pockets of load and generation in connection with the merged company's internal dispatch. This should include hourly determinations of net exports and imports for each of those pockets. The output of this analysis should also include hourly indications of:

(1) the amount of generating capacity probabilistically determined to be available from each generating resource owned and purchased by the merged company,

(2) the amount of that capacity dedicated to native load,

(3) the amount dedicated to firm off-system sales and

(4) the amount available for additional off-system sales.

b. Load flow and stability analyses of necessary additions of equipment (and employment of must-run generation) to support transmission voltages within a +/- 5% range of nominal voltage under base case conditions, heavy transfer conditions and under all single contingency outage conditions. The starting conditions should reflect alterations of internal dispatch that Applicants expect to occur in the post-merger scenarios. The SPP region requires this level of voltage support in order to provide reliability. Utilities whose voltage standards are not as strict are deemed to impose risks and/or costs upon their neighboring systems and to impair the reliability of the region. I discuss this issue further in my later testimony on conflicting standards for design and operation of transmission, and the need for consistent region-wide transmission system design and operation standards.

c. Analyses of transmission facility additions necessary to integrate operations of Applicants' control areas without impairing Springfield's ability to carry out its planned purchase of a firm unit entitlement from KCPL's Montrose unit. The reliability criteria should include a requirement that Applicants comply with regional reliability standards. See item No. VII below.

Q. Has your firm conducted a load flow study of the pre- and post-merger system conditions?

A. Yes. Before we received the SPP study results, a limited study was conducted under my supervision concerning the adequacy of the Missouri transmission system, and that study indicates that problems exist. My study focused on Applicants' transmission system, but monitored the entire Missouri transmission system under summer peak conditions, both normal conditions and conditions with heavy power transfers.

Load flow data for Summer 2000 and 2001 peak base cases were made available by UtiliCorp through Data Response EDSPR-28. Despite its clear intention to alter internal dispatch through integration of its separate control areas, UtiliCorp did not provide post-merger load flow base cases that reflected that altered dispatch as we requested in our original Data Request EDSPR-28. In answer to a follow-up data request, UtiliCorp (referred to as "UCU" in the data response) responded:

For the purposes of transmission system analysis in the SJLP and EDE interconnection studies, UCU did not vary the post-merger dispatch from the pre-merger dispatch. For transmission system analysis only, the expected post-

merger dispatch can be adequately represented using the pre-merger dispatch in provided cases.

(Schedule- (WAR-3), response from UCU's Mr. Gary Clemens to my partner, Ms. Sedina Eric's e-mail on March 28, 2000, last paragraph)

This response confirms that Applicants failed to address one of the issues in this proceeding most important to the public interest: How will Applicants' merger and related operational integration affect the transmission capacity now available to other entities in Missouri and surrounding regions?

Any transmission system analysis of the post-merger conditions based on the pre-merger dispatch of the Applicants' generator capacity will not address, let alone answer, this question. Because the required data has not been made available, my colleague performed her analysis based on the pre-merger dispatch. As I noted, her analysis indicates the existence of numerous overloads that violate regional design standards.

Q. Please describe the methodology of the study and reliability criteria applied.

A. Two summer base cases for the year 2000 were analyzed, both provided with Data Response EDSPR-28:

1. A base case with normal transfers and
2. A base case with a heavy north-to-south power transfer through Missouri.

Cases for 2001 summer peak conditions were analyzed, as provided with that same data response.

The load flow analysis simulated single contingencies on each transformer and internal line in the UtiliCorp area (called "MIPU" in the load flow data), and all tie lines between UtiliCorp and interconnected areas. The facilities included in the analysis operated at 100 kV and above.

The analysis searched for criteria violations as measured against both UtiliCorp's transmission reliability criteria and the Southwest Power Pool's criteria. Both of these criteria require an examination of how UtiliCorp will operate under first contingency conditions, for summer peak load conditions and require that there be no loss of load, overloaded lines, or abnormally low voltages on the transmission system. (See the 1999 Missouri Public Service FERC Form 715, part 4, and Southwest Power Pool Criteria, July 1999).

Q. What are the results of your study?

A. Our study showed that criteria violations can be expected on the UtiliCorp transmission system under conditions predicted to occur at peak (base case) in both the Summer 2000 and the Summer 2001. In the more stressed case simulating expected levels of heavy north-to-south transfers, violations occurred not only under contingency simulations but also under pre-contingency conditions (normal with all facilities in service). As I noted earlier, this means (in layman's terms) that the MoPub transmission system is weak and unreliable as measured by prevailing engineering standards and might experience even more criteria violations after UtiliCorp integrates the operation of its separate control areas. Under a literal interpretation of industry curtailment rules, MoPub could arguably call for transmission loading relief to stop north-to-south transfers needed by other utilities to lower their costs even in the absence of line outages or other contingencies on the MoPub system.

Q. Did the SPP impact study confirm the same weakness of the Applicants' transmission system as your study showed?

A. Yes. The comparable case, that both SPP and I analyzed, is the 2001 summer peak condition with normal transfer through Missouri. The results of my analysis are fully confirmed by the SPP study results. Moreover, the SPP contingency analysis of the 2001 summer case resulted in a larger number of criteria violations (SPP Impact Study, Page 7), than were identified in my analysis. In addition, the SPP study results show that individual transmission lines are overloaded by percentages that are higher than those reflected in my study.

For example, in my analysis the outage of the 161 kV Greenwood – Lee's Summit line caused the overloading of the following two 161 kV lines:

Pleasant Hill – Lake Winnebago	at 107.2% of emergency ratings
Lake Winnebago – Hook Road	at 101.0 % of emergency ratings.

The same contingency simulated by SPP resulted in the overloading of these two lines and an additional one as follows:

Longview - Hook Road	at 103.6 % of emergency ratings,
Pleasant Hill – Lake Winnebago	at 116.1% of emergency ratings,
Lake Winnebago – Hook Road	at 109.9 % of emergency ratings.

Q. What other criteria violations occur in the SPP system as a result of contingency analysis applied on the 2001 summer base case?

A. An outage of the 161 kV Pleasant Hill – Lake Winnebago line caused the overloading of the 161 kV Pralee – Lee's Summit line. My analysis resulted in the overloading of the Pralee – Lee's Summit line in the amount of 105.6% of the emergency rating. The SPP study showed the overloading to be 112.1% of the emergency rating.

An outage of the 161 kV Lake Winnebago – Hook Road line resulted in the overloading of the Pralee – Lee's Summit line. In my study this line is overloaded to 101% of its emergency rating and, in the SPP study, to 108.8% of its emergency rating.

These are only some examples of the violations that occurred on the same lines in both the study conducted by the SPP and in my study. As I testified earlier, the SPP contingency analysis for the 2001 summer case lists twenty-eight violations.

Q. Please explain the discrepancy in results between the SPP analysis and your analysis, and suggest which results more accurately reflect the likely impacts upon the post-merger system.

A. The load flow cases provided to us by Applicants did not reflect the combined operation of the Applicants' control areas. Consequently, my study analyzes the transmission system in Missouri that simulates pre-merger conditions. The SPP study simulates transfers of the type associated with combined operation of the Applicants' systems. Therefore, the results of the SPP study reflect the more severe conditions that can be expected to occur in the post-merger period.

Q. Did you analyze the impact of the merger on the transmission system conditions in Missouri using sources other than load flow cases?

A. Yes. I analyzed the SPP OASIS curtailment log that contains data on each transaction curtailed in the period from August 28, 1998, to March 31, 2000, (Schedule WAR-4). There are several curtailments of transactions involving Applicants that may not have been imposed if Applicants had been merged. (See Schedule__(WAR-4), the SPP OASIS Curtailments log showing the curtailments of transactions involving at least one of the Applicants). Two schedules - both from SJLP to MIPS (MoPub) in the amount of 10 MW - were fully curtailed on October 10, 1999, at 17:00. A schedule from SJLP to MIPS in the amount of 50 MW was curtailed by 32 MW on May 15, 1999 at 17:00.

A repeat of these transactions and conditions after Applicants have merged would almost certainly impose higher costs on entities other than Applicants because the transactions would be native load network service transactions between Applicants and would not be reported on an OASIS and therefore, as a practical matter, would not likely be curtailed.

Q. Please comment on the curtailments of transactions within the merged company.

A. According to Applicants, they intend to decrease their power purchases and replace that power with increased output from internal generation resources. This post-merger shift in dispatch will result in increased power transfers between parts of the merged company. However, transfers of power within the merged company that serve native load will not be posted on OASIS. Consequently, this additional power transfer within the merged company will be effectively be protected from curtailment. When congestion occurs, the burden of curtailments will be imposed on other parties and other Missouri ratepayers.

Applicants are claiming efficiencies that can only be obtained by increased use of transmission, but have not done the studies to show the impact of such uses on other systems.

Q. Have you identified any other constraint on the transmission system inside Missouri that might have an effect on some of the Missouri customers?

A. Yes. Other constraints are identified as potential limitations to power transfers in the 2000 SPP FERC Form 715 of Associated Electric Cooperative[5]:

> *Part 6: Evaluation of Transmission System Performance*
>
> *Associated facilities that have been identified as potential limitations to power transfers are:*
>
> *Montrose-Clinton 161 kV Line*
>
> *The Montrose-Clinton 161 kV line, owned by Kansas City Power & Light, is currently limited by terminal equipment in Associated's Clinton station. This line has shown up in future year power pool transfer studies as a potential limit to subregional power transfers across Missouri generally in a West to East direction. Associated is currently reviewing their Clinton terminal equipment. It is expected'that upgrades will be in place by the end of 2000.*
>
> *Stockton-Morgan 161 kV Line*

[5] Associated Electric Cooperative is a SERC member.

> *The Stockton-Morgan 161 kV line experiences heavy loadings during North to South transfers across Missouri. This line can limit transfers when the parallel Morgan-Brookline or LaCygne-Neosho 345 kV lines are outaged or when generating units to the south are off line. The line loadings have generally been more severe during off peak periods when generating units are off line for maintenance. The Stockton-Morgan 161 kV line has recently been upgraded. This facility will continue to be monitored to determine if additional uprating or other improvements are required.*
>
> (The 2000 SPP FERC Form 715, Associated Electric Cooperative Part 6, Page 8)

MPS reports that a low voltage problem exists at Clinton if the 161 kV source at Clinton substation is interrupted:

> *The operating and planning studies indicate that there is one area in the transmission system that is critical when looking at power transfers. The problem is in the Clinton, MO [area] where low voltages will result if the 161 KV source at the Clinton 161 KV substation is interrupted. This is considered to be an event with a very low probability of occurrence, so there is no corrective action at this time. The magnitude of the voltage under this contingency is such that the load must be shed.* (The 2000 SPP FERC Form 715, UtiliCorp MPS Part 5).

Some constrained facilities are associated with parts of a 161 kV line[6] extending from the Montrose generation plant of Kansas City Power & Light to Brookline substation – City Utility of Springfield. The line is important to delivering Springfield's entitlement in the Montrose generation plant. The Stockton – Morgan section, as reported in the AECI FERC Form 715, experiences heavy loadings during north to south transfers. Moreover, the line can limit transfers during the outages of 345 kV lines from LaCygne to Neosho and from Morgan to Brookline. An additional parallel line would relieve these constraints.

VI. Commitment To Carry Out Needed Upgrades.

Q. What is your next concern?

A. As noted above, I am concerned that Applicants have conducted insufficient study of the their combined operations. Moreover, Applicants withdrew their request for network transmission service after the SPP impact study showed that many facility upgrades and system reinforcements are required to accommodate the requested service. Under these circumstances, I am very concerned that Applicants have made no specific and binding commitment to construct necessary transmission facilities. Until upgrades identified in the SPP studies are in place, the burden of curtailments will fall on ratepayers of other Missouri utilities.

[6] That line is composed of the sections Montrose – Clinton, Clinton to Osceola, Osceola to Stockton, Stockton to Morgan, and Morgan to Brookline.

Applicants' original limited commitment is provided both in its testimony and in response to Springfield's data request EDSPR-32. Unfortunately, Applicants backed away from their original commitment to make upgrades that SPP found to be needed and have now made new and ineffective representations in their FERC testimony, as I discussed earlier.

Q. Please discuss Springfield's data request EDSPR-32 and Applicants' response thereto.

A. That request and Applicants' response are as follows:

REQUEST:

Please explain in more detail your commitment not to link the Applicants using Network Integration Service if it would 'adversely affect transmission dependent entities.' (page 13 at lines 13-17 and again at page 23 lines 14-19).

a. *What is your definition of 'transmission dependent entities'? Would the definition include retail access customers that do now, or would in the future, obtain generation services from non-affiliates? If not, please explain why not.*

b. *On what basis would 'adversely affect' be measured, and what would be the threshold of acceptable adverse effect?*

c. Please indicate whether point-to-point transmission service would be requested by the applicants if network integration service were not utilized to perform system integration.

RESPONSE:

UCU has made an application to the SPP to put all the merged companies native load under SPP Network Integration Service should the merger occur. An Impact Study is now underway to evaluate the effect on the transmission system in SPP. ***If the study reveals that providing such network service will cause a transmission constraint (adverse effect), then it will be the responsibility of UCU to pay for the required upgrades to eliminate such constraints.*** *With the elimination of such constraints, the transmission system is still available for the use of others, wholesale or retail. [Emphasis added]*

If SPP Network Integration Transmission Service were not available, then UCU would have to either construct transmission facilities, or purchase point to point transmission service.

Q. Why does this response not resolve Springfield's concerns?

A. I believe that this response and other commitments of Applicants are inadequate for several reasons including, but not limited to:

a. Applicants initially sought approval of the merger before they or SPP completed relevant studies. In the meantime, the SPP study was completed and showed that substantial reinforcements are needed in order to prevent a deterioration in transmission system reliability. At that point, Applicants withdrew their application for network service and announced that they were reverting to a plan that would physically interconnect their systems. However, they have made no commitment to carry out the reinforcements that would still be necessary even with the construction of the new facilities UtiliCorp now proposes to build to interconnect with EDE.

b. Applicants must firmly commit to carry out a specific plan of action in advance of merging. Agreements to conform to vaguely defined courses of action in the future will not protect the public interest. UtiliCorp has an incentive to understate the severity of any constraints related to the merger in any study effort and, once the merger is completed, will have an incentive to carry out no upgrades or only minimal upgrades.

c. The merging companies have not committed to joining any particular ISO or RTO that may be able to address these concerns or to put all its Kansas and Missouri transmission assets under the control of a single ISO or RTO. To the extent they upgrade their transmission systems at all, they reserve the right to do so before transferring control over those systems to an ISO or RTO. Thus, they continue to evade making a commitment to abide by the directives of any such ISO or RTO with respect to the upgrades that are "under serious consideration". And they reserve the right to make no upgrades, or upgrades that are ineffective. In their FERC filing, they offer to accept a merger condition requiring that they join an RTO but ask:

> ...only that they not be required to disclose their intentions on that issue any earlier than the date provided by Order No. 2000 for all public utilities to do so – October 15, 2000. That latitude will provide the maximum opportunity for the choices on that issue to become clearer in Applicants' region than they are today, but nevertheless with a reasonably prompt deadline for a decision on this subject of importance to the region. [See Mr. Kreul's FERC testimony at 8.]

Although Applicants request a delay in announcing their plans with respect to an ISO, a delay is not warranted. Applicants, unlike other utilities, are affirmatively taking steps that threaten to harm other market participants, including other utilities and ratepayers of other utilities. Through the merger, they will gain rights over transmission that could be used to restrict the availability of transmission to others and to undermine competition. In order to protect the public interest, Applicants must make timely and specific commitments to mitigate or eliminate those threats before they merge.

Q. What do you recommend as a remedy for the lack of a clear and binding commitment to build needed transmission facilities?

A. I recommend that Applicants be ordered to take immediate steps to permit and construct the Nevada-Asbury line[7] and also any transmission lines identified as being necessary in the studies I recommend be done in connection with Item V above, all at Applicants' expense.

VII. Conflicting Standards For Design And Operation Of Transmission

Q. What is your next concern?

A. I am concerned that the individual companies being merged do not adhere to a single, consistent set of standards for designing and operating their transmission facilities.

For example, it appears that both UtiliCorp and Empire District Electric allow voltage to drop 10% below nominal voltage as a part of their design and operation standards. Some voltages in the Empire area are more than 10% below nominal in the 2001 SPP base case load flow. By contrast, St. Joseph L&P allows voltages to range from 94% to 110% of nominal.[8] SPP standards require:

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[7] Applicants conducted a study analyzing the interconnection between UtiliCorp and Empire (Richard C. Kreul Testimony, Schedule RCK-10, page 11 of 11, PSC filing in the UtiliCorp/Empire proceeding). UtiliCorp recommended addition of a 161 kV line between Nevada (UtiliCorp) and Asbury generating station (Empire) that parallels the limiting facility, Stockton – Morgan. The Nevada-Asbury line provides back-up transfer capacity. If UtiliCorp constructs the line between Nevada and Asbury, it will relieve the limiting section (Stockton-Morgan) and increase the transfer capability of a part of the Missouri system that is important to transferring Montrose power to Springfield.

[8] See the St. Joseph L&P FERC Form 715, Part 4.

Sufficient reactive capacity shall be provided within the SPP electric system at appropriate places to maintain transmission system voltages within plus or minus 5% of nominal when more probable contingencies occur.

(See the SPP Criteria, July 1999, at page 3-1)

The SPP criteria discuss problems that may arise if the standards are not enforced:

System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions or all of the interconnected network. Acceptable minimum and maximum voltages are network and system dependent.

(See the SPP Criteria, July 1999, at page 4-2)

Q. What do you recommend as a remedy for this concern?

A. I recommend that Applicants commit to establish and implement a single standard for transmission system design and operation for the entirety of the merged company and, at the very least, commit to comply with the Southwest Power Pool Criteria.

VIII. COMMITMENT NOT TO SET ASIDE TRANSMISSION CAPACITY FOR CAPACITY BENEFIT MARGINS ("CBM") OR TRANSMISSION RESERVE MARGINS ("TRM").

Q. *What is your next concern?*

A. I am concerned that Applicants will attempt to set aside transmission capacity for capacity benefit margins or transmission reserve margins. The set asides will soak up available transmission capacity for use by others on a firm basis. If transmission capacity is not a limiting factor, such set asides have few economic consequences. But, if constrained interfaces are anticipated, setting aside capacity for CBM or TRM will deny needed capacity to other users of the constrained facilities.

Current NERC policies allow transmission owners to set aside transmission capacity for CBM and TRM. While these policies are being evaluated and changes in these policies may occur as a result, the Commission should condition any approval of the mergers upon Applicants' agreeing to limit claims for CBM or TRM.

I therefore recommend that UtiliCorp be required as a condition of the approval of the merger to agree (a) not to set aside transmission capacity for CBM and TRM and (b) to waive any future claims for CBM and TRM.

IX. Commitment Not To Refunctionalize Transmission Lines Operating At Or Above 69 kV.

Q. What is your next concern?

A. I am concerned that Applicants will refunctionalize their transmission facilities in ways that will be anti-competitive. FERC Order No. 888 permits utilities to refunctionalize their transmission facilities to distribution or generation under the so-called seven-factors test set forth in Order No. 888. A number of utilities have refunctionalized in a manner that creates anti-competitive impacts. Although it is not necessary in this testimony to detail all of the potential problems which may arise, I would point out that unwarranted shifts in costs may impose costs upon customers which are not appropriate and be used to protect a utility's customers from competition from alternative sources of supply. There may also be competitive issues raised regarding more favorable treatment of the utility's own generation resources, discouragement of on-site cogeneration or distributed generation projects and denial of appropriate jurisdictional protection.

I therefore recommend that UtiliCorp commit not to seek refunctionalization of any currently categorized transmission lines of the merging companies that operate at or above 69 kV.

X. MARKET POWER

Q. Have Applicants conducted any analysis of the effect of their merger upon market power?

A. Yes. On November 23, 1999, Applicants filed testimony at the FERC for consideration of the two simultaneous but separate mergers of the three companies. Dr. Mark W. Frankena, an economist, filed testimony in support of the merger indicating little, or no, concern for market power implications. In his testimony, however, he assumed the validity of supporting testimony filed by certain other company witnesses, including Mr. Richard C. Kreul. As already indicated, I take exception to some of the assumptions or tentative mitigations which Mr. Kreul advances in his testimony, and my exceptions were confirmed in the SPP System Impact Study.

Q. What is your response to Dr. Frankena's findings?

A. As an engineer, the issue for me is not whether Applicants possess market power in relevant markets as measured by the Herfindahl-Hirschman Index or can benefit from exercising that market power. Instead, the issue is whether Applicants will be able to usurp valuable, limited transmission capacity necessary for other Missouri utilities to maintain deliveries under their purchased power contracts. That is, the question is whether the merger gives the Applicants the opportunity, ability and incentive to utilize scarce transmission resources for their own use leaving other utilities with no economic alternatives for the delivery of their needed power supplies.

For energy consumers in Missouri, this is an important consideration. If transmission serving the State becomes constrained, it will not be possible to dispatch the most cost-effective combination of generating resources. Re-dispatch will be required, and energy costs necessarily will rise. Constrained interfaces can lead to severe price spikes. In more severe cases, transmission constraints can suppress voltage to unacceptable and unreliable levels and cause customers to be cut off or, worse yet, cause cascading failures. The Commission should therefore impose a condition on its approval of the mergers to require Applicants to make upgrades in the transmission infrastructure (much of which is not owned by the Applicants) so as to preserve existing benefits. Although benefits are likely to be achievable through the merger, they should be achieved through synergies associated with the merger and not be the result of diverting benefits to Applicants at the expense of other energy providers and consumers in Missouri.

Q. What specific findings do you question?

A. Dr. Frankena appears to dismiss transmission market power concerns entirely on page 13 of his testimony by arguing that the presence of regional tariffs (MAPP and/or SPP) will make it "unlikely" for the Applicants to increase transmission market power.[9] I understand that the MAPP ISO negotiations have fallen apart and that the MAPP regional

[9] This point is reiterated at page 35, lines 16-18 where Dr. Frankena states: "I rely primarily on facts presented in the testimony of Mr. Kreul to conclude that the proposed mergers do not raise concerns about transmission market power."

transmission tariff does not satisfy many of the minimum requirements of an ISO or RTO.

The evidence suggests Dr. Frankena's reliance upon regional transmission tariffs to prevent damage to competition is too conclusory. The trade press reports almost daily that even when they are under the control of regional transmission organizations or ISOs, market participants can game the system. Thus, the mere existence of regional transmission tariffs does not in itself insure that a merger will not afford Applicants increased ability and incentive to exercise forms of market power that are too subtle to be captured by traditional analyses of market power.

Q. Please continue.

A. A key element to be analyzed in assessing impacts of electric utility mergers is the regional transmission system. Increased attention is being paid to this sector of the electric system in recent years, and it is no exaggeration to say that this has become the central point of concern for parties seeking to compete in electric power markets. For companies seeking to merge and utilize the intervening transmission system in order to achieve merger benefits, the impacts upon the use of the transmission system by third parties is a complex and contentious concern. In these mergers, this consideration has been exacerbated by the lack of study devoted to this issue by Applicants.

Dr. Frankena has gone to considerable lengths to try to dismiss concerns regarding competitive impacts. He argues, correctly, that if the relative size of Applicants' current systems is considered, the concern regarding market power appears slight. However, while correct in a global context, such an approach may mask serious concerns of a more local nature. These impacts may not translate directly into increased economic benefits via the exercise of market power, the traditional concern examined by DOJ/DOE market power screening tools. However, they may present obstacles to other market participants who rely upon the, at times, fragile transmission infrastructure in the region.

Applicants themselves appear to be cognizant of such impacts. In their original applications, they provide facility reinforcement schemes designed to address just such concerns. However, they do not pledge to develop such projects as a pre-requisite to merging. Rather, they utilize these plans as a proxy to indicate that, even if such projects were constructed, the benefits to Applicants would outweigh the estimated construction costs. The transmission facility upgrades thus become fictional characters in a cost/benefit analysis, useful for justifying the merger before regulatory bodies, but providing no substantive assurance to third parties that such transmission upgrades will ever materialize, or if so, at whose expense.

An April 17, 2000, letter to Applicants (Schedule _ WAR-8) from FERC's Director of the Division of Applications raises concerns about the failure of Applicants' to evaluate the impact of their integrated operations upon access to power markets. FERC Staff letter stated:

> … changes in Applicants' integration plans and transactions announced subsequent to the filing of your [Applicants'] merger application constitute significant changes in your merger proposal requiring revisions to your competitive analysis….

> See Schedule__(WAR-6).

The Applicants were considering a least cost option which would allow them to utilize existing regional transmission facilities as the preferred mechanism upon which to integrate the combined operation of the merged companies. However, as I noted earlier, when confronted with the SPP System Impact Study, Applicants determined that "it does not appear fruitful for UtiliCorp to continue to pursue the application for network service with the SPP, and to incur the related costs of that process, at the present time." See Mr. Kreul's FERC testimony at 4. They withdrew their request for service under the SPP tariff and now offer instead to give "serious consideration" to two plans for direct interconnection of their Missouri control areas.

Q. Did Applicants respond to the FERC letter?

A. Yes. The response of Utilicorp to the FERC staff April 17, 2000, letter is inconsistent with its prior commitments and is counterproductive. Although the reliability of electric power in the United States depends upon effectively implementing regional solutions to transmission problems, Utilicorp, a purported advocate of the new competitive regime, now positions itself squarely against the prevailing regional solution. Having requested the most relevant transmission authority, the Southwest Power Pool, to determine the appropriate infrastructure necessary and having offered to place itself under SPP's regional tariff, UtiliCorp has turned its back on the process it invoked. Seeking to avoid the full costs of mitigating the adverse impacts upon other users of the transmission system, Utilicorp has apparently elected to "go it alone," reverting to the standards which prevailed prior to the move towards regional solutions. It reserves the right to determine unilaterally what transmission facilities are required and seeks to defer until October 2000 announcing any commitment to submit any specific portions of the merged company's transmission facilities to the control of any specific regional body administering a regional transmission tariff.

SPP should be commended for conducting an analysis which revealed the Emperor's clothes to be an illusion – that Applicants' intended mode of joint operation would impose costs upon the system greater than the Applicants had originally estimated, and greater than they are apparently willing to pay. By forcing these costs to be paid by others and by refusing to submit to a regional tariff for network service, Applicants seek to enhance their own profits at the expense of other users of the transmission system.

In contrast to Applicants' current declaration that they have always stated that their merged systems would be operated as a single control area, Mr. Kreul stated on page 9 line 14-15 of his direct testimony: "The two systems **may be** operated as a single regional control area after the two companies are merged." [Emphasis added] His direct testimony conditions his answers upon the possibility, not the assurance, that such integrated operation would be implemented. This is evidenced by his repeated use of the preposition "if."

Applicants now term the initially proposed transmission facilities as "contemplated originally as the **likely integration option**." (see Response of Applicants to Letter Order Dated April 17, 2000 page 3). Once again this is not the testimony of Mr. Kreul. On pages 11 and 12 of his direct testimony, Mr. Kreul speaks of the transmission-build option as being only an option that may or may not be "warranted." At no time does he define his terminology. On page 12, he speaks of an RTO solution but importantly reserves to the Applicants, and not the regional authority, the right to determine whether "additional transmission construction is not necessary." He asserts that:

> UtiliCorp and Empire will not effectuate any interconnection plan that would result in reducing Available Transfer Capabilities ("ATC") into or out of UtiliCorp's and Empire's systems below the level needed for a transmission dependent entity to import energy to serve its load or to export energy from existing generation. (page 12, lines 1-4)

It is now unclear whether Applicants are committed to do anything. Moreover, it is even less clear as to whom (if anyone) the Applicants are willing to defer in judging whether their commitments have been honored.

More questions are raised by Mr. Kruel's supplemental testimony in FERC Docket (EC 00-27-000 and EC 00-28-000) than answered. On pages 3-4, he states:

> *It appears that on further study that the comparative benefits to the merged companies' operations of integrating through the use of network service under the SPP tariff will be inferior to those which can be obtained through the construction of the above-described new lines joining the merged companies' systems.*

He does not provide the study or any support for it nor does he indicate to whom the purported "benefit" will accrue (although it is safe to assume that it is to the Applicants). Nor does he mention whether the construction option will insure no adverse impact upon other transmission users. He does not indicate in what manner the SPP tariff will provide service that is inferior or what detriments to other users will result under the construction option. Clearly, costs to other parties must be weighed in determining the public interest. In addition, Dr. Frankena conducted a new market power study and prepared Supplemental Testimony for the FERC (Schedule__WAR-8).

Q. Does Dr. Frankena's new market power study satisfy your concerns?

A. No. On the contrary, his new study raises even more concerns. Dr. Frankena's Supplemental Testimony filed at FERC maintains his same conclusions, that he does not believe that there are market power concerns that need to be mitigated. However, he abandoned the absolute statements made in his direct testimony. Previously, he could affirm that "There is not a single one among 3,960 cases in which the proposed mergers yield HHI results above the Commission's competitive screening thresholds." (Direct at page 10, line 14-16). He is now reduced to pleading that "the supplemental HHI results are not significantly above the Commission's safe harbor levels." (Supplemental at page 5 lines 12-13). This is odd given that Applicants assert that their current options are and always have been the "likely" integration plan that the Applicants envisioned.

Dr. Frankena indicates that he has updated data, among which are data indicating that there will be additional generating capacity that is not owned by Applicants. However, contrary to what one would expect, this additional competition in generation causes screen violations that previously did not exist. Dr. Frankena does not offer any explanation for this.

Q. What do you conclude from these actions on the part of the Applicants?

A. UtiliCorp's history of reversing its commitment to make upgrades identified as needed in the SPP System Impact Study and of seeking short-term, self-serving economic benefit from exploiting "seams" between regional transmission systems and its reversals of position require that it now give more than vague assurances. Until uniform regional transmission structures and consistent planning and operating standards can be developed, the Commission should closely monitor (and impose needed remedial conditions upon) mergers that allow Applicants to straddle limited transmission interfaces and commandeer limited transfer capability.

If the Applicants are not willing to commit themselves to identify and resolve problems prior to merging and to participate fully in an established regional solution, the only alternatives are:

1. To deny the merger or
2. To impose strict conditions upon the merging parties as set forth in this testimony.

Q. Does this conclude your testimony?

A. Yes, at this time.

WHITFIELD A. RUSSELL

Whitfield A. Russell is an Electrical Engineer and President of Whitfield A. Russell and Associates, P.C., a corporate Partner of Whitfield Russell Associates. He holds a Bachelor of Science degree in Electrical Engineering from the University of Maine at Orono, a Master of Science in Electrical Engineering from the University of Maryland, and a Juris Doctor degree from Georgetown University Law Center.

Mr. Russell is experienced in electric utility system planning, power pooling, ratemaking and bulk power contract negotiation. Mr. Russell has been qualified as an expert witness in 27 states (as well as in the Province of Alberta and the District of Columbia) and has testified in more than 100 proceedings before state and federal Courts, arbitration panels, public service commissions, the Federal Energy Regulatory Commission and other administrative agencies. Mr. Russell has written and spoken extensively on matters relating to regulated electric utilities.

From 1972 to 1976, Mr. Russell served as Engineer and subsequently as Chief Engineer, at the Division of Corporate Regulation of the Securities and Exchange Commission. The Division administers the Public Utility Holding Company Act of 1935.

From 1971 to 1972, Mr. Russell was on the staff of the Federal Power Commission. He served as a consultant to staff attorneys in proceedings, and as an expert witness in an administrative proceeding before the Atomic Energy Commission.

From 1969 to 1971, Mr. Russell served as an Associate Engineer in the System Planning Division of the Potomac Electric Power Company. At PEPCO, he conducted system studies of load flows and stability. He was also a member of numerous study groups concerned with planning and operation of the Pennsylvania-New Jersey-Maryland Interconnection.

PROCEEDINGS IN WHICH WHITFIELD A. RUSSELL HAS TESTIFIED

1. Anaheim v. Kleppe, U.S. District Court, Arizona (Civil No. 74-542 PHX-WEC), concerning the availability of transmission capacity in the Pacific Southwest.

2. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 7004, concerning the need for proposed 500 kV transmission lines in the Washington, D.C. area.

3. In re: Baltimore Gas and Electric Company, and Potomac Electric Power Company, before the Maryland Public Service Commission, Case No. 6984, involving the same transmission lines mentioned in the preceding case.

4. Perry v. The City of Monroe, Louisiana (State of Louisiana, Parish of Ouachita, Fourth District Court; Nos. 111145, 111146, 111147 filed August 16,1977) regarding the necessity of Monroe's disposing of its municipal utility system.

5. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, in Case No. 685, concerning the system planning of the Potomac Electric Power Company and the PJM Pool.

6. In re: Generic Hearings on Rate Structure, before the Colorado Public Utilities Commission, Case No. 5693, regarding the engineering aspects of marginal cost pricing and power pooling in Colorado.

7. In re: Pacific Gas and Electric Company, FERC Docket No. ER76-532, regarding the proper level of rates to be charged by PGandE to the Central Valley Project for transmission service.

8. In re: Pacific Power and Light Company, FERC Docket No. E-7796, regarding the Seven Party Agreement and related matters.

9. In re: Pacific Gas and Electric Company, FERC Docket No. E-7777 (II), concerning the provisions of numerous bulk power arrangements governing electric utilities in California.

10. <u>In re: Potomac Edison Company</u>, before the Maryland Public Service Commission, Case No. 7055, concerning the need for a 230 Kv transmission line in Montgomery County, Maryland.

11. <u>In re: Delmarva Power and Light Company</u>, before the Maryland Public Service Commission, Case Nos. 7239F, 7239G, 7239H, 7239I, 7239J, 7239K, 7239L, 7239M and 7239N concerning fuel rate adjustments.

12. <u>In re: Baltimore Gas and Electric Company</u>, before the Maryland Public Service Commission, Case Nos. 7238G, 7238H, 7238I, 7238J, 7238L and combined dockets 7238P, Q, R and S, concerning fuel rates.

13. <u>In re: Potomac Electric Power Company</u>, before the Maryland Public Service Commission, Case Nos. 7240A, 7240B, 7240C, 7240D, 7240E, 7240F and 7240G, concerning fuel rate adjustments.

14. <u>In re: Florida Power & Light Company</u>, FERC Docket No. E-9574, concerning system planning for the City of Vero Beach, Florida. FP&L withdrew its application to acquire the Vero Beach system.

15. <u>In re: Oklahoma Gas and Electric Company</u>, FERC Docket No. ER77-465, concerning rates for energy banking and transmission services rendered to the Western Farmers Electric Cooperative.

16. <u>In re: Idaho Power Company</u>, before the Idaho Public Utility Commission, Case No. U-1006-158, concerning the value of interruptible industrial loads and Idaho Power Companies entitlement to Federal secondary energy.

17. <u>In re: Potomac Electric Power Company</u>, before the District of Columbia Public Service Commission, Case No. 737, concerning the Company's construction program.

18. <u>In re: Virginia Electric and Power Company</u>, before the Virginia State Corporation Commission, Case No. PUE 800006, concerning construction of transmission lines in the Charlottesville, Virginia area.

19. <u>In re: Pacific Gas and Electric Company</u>, FERC Project Nos. 2735 and 1988, concerning the Helms Project, a pumped storage generating unit.

20. Southeastern Power Administration v. Kentucky Utilities Company, FERC Docket No. EL 80-7, concerning SEPA's attempt to obtain a FERC wheeling order under the Public Utility Regulatory Policies Act of 1978.

21. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-105, concerning construction and transmission planning.

22. In re: Virginia Electric and Power Company, before the North Carolina Utilities Commission, Docket No. E-22, Sub 257, concerning production cost simulation and normalized fuel adjustment clause formula.

23. In re: the Investigation of the Capital Expansion For Electric Generation, before the New Mexico Public Service Commission, Case No. 1577, concerning construction programs of the Public Service Company of New Mexico and El Paso Electric Company.

24. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case Nos. 7241A, 7241B, 7241C and 7241D, concerning fuel rate adjustments and productivity of generating units.

25. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7528, concerning the method of calculating Potomac Edison's fuel rate.

26. In re: Delmarva Power & Light Company, before the Maryland Public Service Commission, Docket No. 7570, concerning transmission loss allocation methodology.

27. In re: Nebraska Public Power District, before the South Dakota Public Utilities Commission, Docket No. F-3371, concerning proposed construction and operation of the 500 Kv MANDAN Transmission Facility.

28. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 81-660, concerning construction and transmission planning.

29. In re: Kentucky Utilities Company, FERC Docket Nos. ER-81-341-000 and ER81-267-000, concerning construction planning and the market for short term power.

30. In re: Kentucky Power Company et al., before the Kentucky Public Service Commission, Case No. 8566, concerning cogeneration and avoided costs.

31. In re: Appalachian Power Company, before the West Virginia Public Service Commission, Case No. 82-162-42T, concerning the wholesale market and short-term power sales.

32. In re: Central Maine Power Company, before the Maine Public Utility Commission, Docket No. 82-137, concerning the application of Central Maine Power Company to reorganize in the form of a holding company.

33. In re: Houston Lighting & Power Company, before the Public Utility Commission of Texas, Docket No. 4712, concerning rates to be paid to cogenerators and small power producers.

34. In re: Dow Chemical Company, before the Public Utility Commission of Texas, Docket Nos. 4802, 5050 and 5062, concerning rates for interruptible service.

35. In re: Nevada Power Company, before the Nevada Public Service Commission, Docket No. 83-707, concerning the Reid Gardner No. 4 Participation Agreement.

36. Dow Chemical Company vs. Houston Lighting & Power Company, before the District Court of Brazoria County, Texas, 149th Judicial District, No. 79-F-2620, regarding the custom and usage of contract terms in the electric utility industry. Live direct testimony in a jury trial. No transcript available.

37. In re: The Montana Power Company and the Confederated Salish and Kootenai Tribes of the Flathead Reservation, Project Nos. 5-004 and 2776-000, concerning the Tribes' intention and ability to sell its output to one or more entities in the Western states, if obtaining the license to the Kerr Project.

38. In re: the Dow Chemical Company vs. Gulf States Utilities Company, before the Louisiana Public Service Commission, Docket No. U-16038, concerning cogeneration and small power production.

39. In re: Petition of the Dow Chemical Company, before the Public Utility Commission of Texas, Docket No. 5651, for an order compelling Houston Lighting & Power Company to comply with the Commission Order concerning cogeneration and small power production.

40. In re: Oklahoma Gas and Electric Company, before the Oklahoma Corporation Commission, Cause No. 29017, concerning priority for recognition of capacity costs to Qualifying Facilities.

41. In re: Kansas City Power & Light Company of Kansas City, Missouri, before the Missouri Public Service Commission, Case Nos. ER-85-128 and EO-85-185, regarding rate design and allocation of production-related costs for the Company's Wolf Creek Generating Station on behalf of the United States Department of Energy.

42. In re: Kansas City Power and Light Company, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning operating problems caused by excess capacity, mitigation measures and regulatory requirements, on behalf of Johnson County Joint Intervenors.

43. In re: Duke Power Company, before the North Carolina Utilities Commission, Docket No. E-7, Sub 391, concerning the Company's use of an Extended Cold Shutdown program to mitigate its excess capacity situation resulting from the Catawba Units, on behalf of the Department of Justice for the State of North Carolina.

44. Sierra Pacific Power Company, before the Public Service Commission of the State of Nevada, Docket No. 85-430, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning the effects upon retail rates of placing Valmy Unit No. 2 in service.

45. United States of America Department of Energy, before the Bonneville Power Administration, on behalf of the City of Vernon, California, concerning the 1985 Proposed Firm Displacement Power Rate.

46. In re: City of Anaheim, et al., v. Southern California Edison, Docket No. 78-0810, on behalf of five partial requirements wholesale customers of Southern California Edison Company, making claims under Federal antitrust laws for access to the Pacific Northwest-Pacific Southwest Intertie.

47. In the Matter of the Application of Sierra Pacific Power Company for Approval of its 1986-2006 Electric Resource Plan, Docket No. 86-701, on behalf of the State of Nevada Attorney General's Office of Advocate for Customers of Public Utilities, concerning efforts of Sierra Pacific Power Company to develop a new interconnection (the SMUD Tie) with the Sacramento Municipal Utility District.

48. The Federal Executive Agencies, Complainant v. Public Service Company of Colorado, before the Public Utilities Commission of the State of Colorado, Case No. 6551, on behalf of the Federal Executive Agencies concerning the feasibility of wheeling federal preference power to the Government's facilities at Rocky Flats, the Lowry Air Force Base, the Rocky Flats Technical Center and the Denver Federal Center.

49. Commonwealth Edison Company, before the State of Illinois, Illinois Commerce Commission, Docket Nos. 87-0043, 87-0044 and 87-0057 Consolidated, on behalf of Intervenor, Citizen's Utility Board of Illinois, concerning Edison's proposal to form a generating subsidiary.

50. Nevada Power Company, before the Nevada Public Service Commission, Docket No. 87-750, concerning a 345 KV transmission line proposed to connect Nevada Power Company to Utah Power and Light Company.

51. Utah Power & Light Company, PacifiCorp, PC/UP&L Merging Corporation, FERC Docket No. EC88-2-000, establishing conditions for the proposed merger; also challenging PP&L's/UP&L's assertion that the claimed coordination benefits would not be attainable through power pooling or by contract.

52. Rosemount Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation vs. Northern States Power Company, before the Minnesota Public Utilities Commission, Docket No. E-002/GG-88-491, on behalf of Petitioners, Rosemount

Cogeneration Joint Venture, Biosyn Chemical Corporation and Oxbow Power Corporation, concerning a contract between Northern States Power and Biosyn Chemical Corporation covering the 50 MW output of a yet-to-be-constructed power plant based on the forecast costs of Sherburne County Unit #3 ("Sherco Unit 3").

53. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 869, on behalf of the District of Columbia Office of the People's Counsel, concerning the prudence of off-system purchases.

54. In re: Wisconsin Public Power Inc. System, Advance Plan 5, before the Public Service Commission of the state of Wisconsin, on behalf of the Wisconsin Public Power System, Inc., concerning transmission planning in the state of Wisconsin.

55. In re: Nevada Power Company, before the Public Service Commission of Nevada, Docket No. 88-701, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning NPC's 1988 Resource Plan.

56. In re: Commonwealth Edison Company, before the Illinois Commerce Commission, Docket Nos. 87-0427, 87-0169, 88-0189 and 88-0219, on behalf of the Citizens Utility Board, concerning rejection of an unfair, Staff-proposed rate order.

57. In re: Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8425, 8431, on behalf of The Dow Chemical Company, concerning application of Houston Lighting & Power Company for authority to change rates; Fuel Reconciliation, Revenue Requirements and Rate Design.

58. Dow Chemical Company vs. Houston Lighting & Power Company, before the Texas Public Utilities Commission, Docket No. 8555, on behalf of The Dow Chemical Company, concerning rate discrimination, cost to serve and class load characteristics.

59. In re: Sierra Pacific Power Company, before the Public Service Commission of Nevada, Docket No. 89-676, on behalf of the Attorney General's Office of Advocate for Customers of Public Utilities, concerning Sierra's system planning.

60. In re: Northern California Power Agency vs. Pacific Gas and Electric Company, before the Federal Energy Regulatory Commission, Docket No. EL89-4-000, on behalf of the Northern California Power Agency ("NCPA"), concerning the Interconnection Agreement between Pacific Gas & Electric Company and NCPA.

61. In re: M-S-R Public Power Agency vs. Tucson Electric Power Company, before the United States District Court of Arizona, No. CIV-86-521-TUC-ACM, on behalf of M-S-R, concerning TEP's breach of contract.

62. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC89-5-000, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access.

63. In re: Farmers Electrical Cooperative Corporation and City Water & Light Plant of the City of Jonesboro, Arkansas, v. Arkansas Power & Light Company, No. LR-C-86-118. Presented deposition testimony on AP&L's liability and assisted in settlement negotiations of treble damage claims for transmission line foreclosure made by plaintiffs, City Water and Light Department of Jonesboro, Arkansas and the Farmers Electric Cooperative.

64. In re: Southern California Edison Company and San Diego Gas & Electric Company, before the California Public Utilities Commission, Docket No. 88-12-035, on behalf of the City of Vernon, California concerning expected effects of the proposed merger on competition, system operation and transmission access.

65. In re: Northeast Utilities Service Company and Public Service Company of New Hampshire, before the Federal Energy Regulatory Commission, Docket Nos. EC90-10-000, ER90-143-000, ER90-144-000, ER90-145-000 and EL90-9-000, on behalf of Massachusetts Municipal Wholesale Electric Company, concerning the effect of a proposed merger on competition and transmission access.

66. Report to the Public Utilities Board of Manitoba concerning 1990 Manitoba Hydro Capital Projects Review: Generation and Transmission Requirements. Whitfield Russell Associates was

appointed to report to The Public Utilities Board on matters regarding the economic consequences to the domestic customers of the Manitoba Hydro capital program.

67. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket Nos. ER90-373-000, et al., on behalf of the Massachusetts Municipal Wholesale Electric Company, evaluating the Preferred Transmission Service Agreement between MMWEC and Northeast Utilities Service Company, for the transmission of MMWEC's power purchase from the New York Power Authority.

68. In re: New Hampshire Electric Cooperative Rate Plan Proposal, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

69. Tampa Electric Company v. Zeigler Coal Company. This was an arbitration held in August 1991, concerning provisions of a coal contract in which Mr. Russell offered testimony for Zeigler to the effect that Tampa Electric was not suffering a hardship by measures commonly used in the electric utility industry.

70. In re: The Long Range Forecast of Ohio Power Company, before the Ohio Public Utilities Commission, Docket No. 90-660-EL-FOR (Phase II). Mr. Russell presented and defended testimony on behalf of Ormet Aluminum Corporation concerning Ormet's right to allowances to emit sulfur dioxide from the Kammer Power Plant of Ohio Power Company under the Clean Air Act Amendments of 1990 and the propriety of Ohio Power's Compliance Plan.

71. In re: Application of Tex-La Electric Cooperative to Increase Rates. Mr. Russell presented testimony in 1991, demonstrating that Tex-La was prudent in selling its entitlement in a nuclear plant and in settling its 1988 claims against Texas Utilities concerning Texas Utilities' fraud and imprudence in the construction of the Comanche Peak Nuclear Plant.

72. In re: Southern California Edison Company, before the Federal Energy Regulatory Commission, Docket No. ER88-83, on behalf of the City of Vernon, California concerning expected effects of Edison's administration of its transmission network on competition, system operation and transmission access.

73. In the Matter of the Application of the Public Service Company of New Mexico for Approval to Construct, Own, Operate and Maintain the Ojo Line Extension and for Related Approvals before the New Mexico Public Service Commission, Case No. 2382, on behalf of the United States Department of Energy, concerning transmission line construction programs of the Public Service Company of New Mexico.

74. In re: Wisconsin Public Power Inc. System et al., Advance Plan 6, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EP-6, concerning Eastern Wisconsin Utility Joint Transmission System and Interface Study.

75. In re: MidAtlantic Energy v. Monongahela Power Company and the Potomac Edison Company, before the Public Service Commission of West Virginia, Case No. 89-783-E-C, on behalf of MidAtlantic Energy, concerning need for capacity and the appropriate avoided cost.

76. In re: Northeast Utilities Service Company, before the Federal Energy Regulatory Commission, Docket No. EL91-36-000, on behalf of the Massachusetts Municipal Wholesale Electric Company evaluating the tie-line adjustment charge borne by MMWEC that arose under a Transmission Service Agreement between New England Power Company and Northeast Utilities.

77. In re: Application of Houston Lighting & Power Company for a Certificate of Convenience and Necessity for the DuPont Project, before the Public Utility Commission of Texas, Docket No. 11000, on behalf of Destec Energy, Inc.

78. In re: Investigation on the Commission's Own Motion into Barriers to Contracts Between Electric Utilities and Nonutility Cogenerators and Certain Related Policy Issues, before the Public Service Commission of the state of Wisconsin, Docket No. 05-EI-112, on behalf of JOINT PARTIES: DESTEC Energy, Inc., EnerTran Technology Company, LS Power Corporation, The AES Corporation, LG&E Development Corporation, National Independent Energy Producers, and Citizens' Utility Board, concerning appropriate QF contract provision.

79. In re: Application of Cap Rock Electric Cooperative, Inc. for a Certificate of Convenience and Necessity, before the Public Utility Commission of Texas, Docket No. 11248, on behalf of Cap Rock Electric Cooperative, Inc., concerning its proposed transmission system improvements.

80. In re: Application of Texas Utilities for Authority to Change Rates, before the Public Utility Commission of Texas, Docket No. 11735, on behalf of Cap Rock Electric Cooperative, Inc., concerning standby rates, wholesale rate contracts and terms and conditions of the Power Sales Agreement.

81. In re: Determination of Houston Lighting & Power Company's Standard Avoided Cost Calculation for the Purchase of Firm Energy and Capacity from Qualifying Facilities Pursuant to P.U.C. Subst. R. 23.66(H)(3), before the Public Utility Commission of Texas, Docket No. 10832, on behalf of Destec Energy, Inc.

82. In re: Complaint of Phibro Refining, Inc. v. HL&P, Docket No. 11989, before the Public Utility Commission of Texas, on behalf of Phibro Energy, USA, Inc., concerning electric service contracts and terms and conditions of HL&P's industrial rate schedule.

83. In re: Application of Texas Utilities Electric Company for Authority to Implement Economic Development Service, General Service Competitive Pricing, Wholesale Power Competitive Pricing, and Environmental Technology Service, Docket No. 13100, before the Public Utility Commission of Texas, on behalf of Rayburn Country Electric Cooperative, Inc., concerning TU Electric's so-called "competitive rates."

84. In re: Complaint of Kenneth D. Williams v. HL&P, Docket No. 12065, on behalf of Destec before the Public Utility Commission of Texas.

85. In re: Rebuttal testimony in a Complaint of Tex-La v. TUEC, Docket No. 12362, on behalf of Rayburn County Electric Coop. before the Public Utilities Commission of Texas.

86. In re: Application for Authorization and Approval of Merger Between Wisconsin Electric Power Company, Northern States Power Company (Minnesota), Northern States Power Company (Wisconsin), and Cenergy, Inc., in Docket No. EC-95-16-000, before

the Federal Energy Regulatory Commission (on behalf of Certain Intervenors, including Madison Gas & Electric Company, Wisconsin Public Service Corporation, Minnesota Power & Light Company, Otter Tail Power Company and the Lincoln Electric System), in Docket Nos. 6630-UM-100 and 4220-UM-101, before the Wisconsin Public Service Commission and Docket No. 6-2500-10601-2 before the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (both on behalf of Madison Gas & Electric, Wisconsin Industrial Energy Group, Wisconsin Federation of Cooperatives and the Citizen's Utility Board), concerning the effect upon transmission access of the merger of NSP and WEPCO into Primergy.

87. In re: Merger of The Washington Water Power Company and Sierra Pacific Power Company, Docket Nos. EC94-23-000 and ER95-808-000, before the Federal Energy Regulatory Commission, on behalf of Truckee Donner Public Utility District, concerning ancillary services and single system transmission rates.

88. In re: Alberta Electric Utilities 1996 Tariff Application before the Alberta Energy And Utilities Board, on behalf of the Industrial Power Consumers Association of Alberta concerning calculation of charges for ancillary services.

89. In re: Surrebuttal Testimony in Docket Nos. EC95-16-000, ER95-1357-000 and ER95-1358-000, on behalf of Madison Gas & Electric Company, Citizens Utility Board and Wisconsin Electric Cooperative Association.

90. In re: City Public Service Board of San Antonio Filing in Compliance with Subst. Rule 23.67, Docket No. 15613, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

91. In re: City of Austin Filing in Compliance with Subst. Rule 23.67, Docket No. 15645, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

92. In re: Central Power and Light and West Texas Utilities Filing in Compliance with Subst. Rule 23.67, Docket No. 15643, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

93. In re: Texas Utilities Electric Company, Filing in Compliance with Subst. Rule 23.67, Docket No. 15638, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

94. In re: Docket No. 15840, Regional Transmission Proceeding to Establish Postage Stamp Rate and Statewide Load Flow Pursuant to P.U.C. Subst. Rule. 23.67 on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

95. In re: Rebuttal Testimony on behalf of MG&E, WIEG, WFC, CUB in Docket Nos. 6630-UM-100 and 4220-UM-101 before the Public Services Commission of Wisconsin.

96. In re: Houston Lighting & Power Company Filing in Compliance with Subst. Rule 23.67, Docket No. 15639, before the Public Utility Commission of Texas, on behalf of Certain Power Marketers and Independent Power Producers, Destec Power Services and Enron Power Marketing, concerning Ancillary Services under the state-wide rate in Texas.

97. In re: IES Utilities, Inc., Interstate Power Company, Wisconsin Power & Light Company, South Beloit Water, Gas & Electric Company, Heartland Energy Services, and Industrial Energy Applications, Inc., Docket Nos. EC96-13-000,ER96-1236-000, and ER96-2560-000, before the Federal Energy Regulatory Commission, on behalf of Wisconsin Intervenors ("WI"). Mr. Russell simultaneously filed 2 sets of testimony; the first, sponsored by the intervenors listed above as well as by Wisconsin Public Service Corporation ("Pub Service"), and Dairyland Power Cooperative. ("Dairyland") analyzed engineering and operating problems created by the merger of WP&L, IPW and IES. The second set of testimony discusses how

the IEC Independent System Operator ("ISO") fails in general to meet the rigorous and comprehensive ISO standards promulgated by the Wisconsin Public Service Commission (WPSC). Both sets of testimony (Engineering and ISO) were filed before the Federal Energy Commission.

98. In re: Joint Application of WPL Holdings, Inc. and Wisconsin Power & Light Company for all Requisite Approvals in Connection with a Series of Related Transactions by which Interstate Power Company Becomes a Subsidiary of WPL Holdings, Inc., IES Industries, Inc. is Merged into WPL Holdings, Inc. and is Renamed Interstate Power Corporation and for Certain Related Transactions and Matters, in Docket No. 6680-UM-100, before the Public Service Commission of Wisconsin.

99. In re: City of College Station, FERC Docket No. TX 96-2-000, concerning transmission rates.

100. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00973981 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission.

101. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, in Docket No. R-00974104 on behalf of Mid-Atlantic Power Supply Association, before the Pennsylvania Public Utility Commission.

102. In re: New England Power Company, FERC Docket No. OA96-74-000, concerning proposed formula rates for Tariffs No. 9 and 4, on behalf of the Massachusetts Municipals.

103. In re: Sierra Pacific Power Company before the Federal Energy Regulatory Commission in Docket Nos. ER97-3593-000, ER97-3779-000, ER97-4462-000 on behalf of Truckee Donner Public Utility District, addressing lack of comparable access to transmission systems.

104. In re: Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, in Docket Nos. 97-11018 and 97-11028, before the Public Service Commission of Nevada.

105. In re: Southern California Edison Company before the Federal Energy Regulatory Commission in Docket No. ER97-2355-000 on behalf of Department of Water Resources of the State of California, regarding lower pricing for off-peak transmission services.

106. In re: Response to Procedural Order Number Three Load Pockets, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Number 97-8001, before the Public Utilities Commission of Nevada.

107. In re: Supplemental Testimony in an Application for Approval of Restructuring Plan Under Section 2806 of the Public Utility Code, on behalf of Newmont Gold Company and Barrick Goldstrike Mines, Docket Numbers 97-11018 and 97-11028, before the Public Utilities Commission of Nevada.

108. In re: Southern California Edison Company, on behalf of The Department of Water Resources of The State of California, Docket No. ER97-2355, before FERC in reference to Transmission Revenue Balancing Account Adjustment ("TRBAA").

109. In re: Ormet Primary Aluminum Corporation, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association, concerning the relationship between AEP and other power systems within NERC and ECAR.

110. In re: Rebuttal Testimony in response to Mr. Walter R. Kelley and Mr. Thomas Kennedy, on behalf of Ormet Primary Aluminum Corporation, Arbitration Number 55-199-0051-94, before the American Arbitration Association.

111. In re: Application No. RE95081 – TransAlta Utilities Corp., on behalf of Albchem Industries Ltd., CXY Chemicals and Dow Chemicals Canada Ltd., before the Alberta Energy & Utilities Board addressing ACD's interest in providing interruptible service.

112. In re: Tri-State Generation and Transmission Assoc., Inc., in Arbitration No. 77 Y 181 0023097 before the American Arbitration Association.

113. In re: Joint Application for Approval of Merger, Docket No. 98-7023 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada.

114. In re: Independent System Administrator, Docket No. 97-8001 on behalf of The Staff of the Public Utilities Commission, before the Public Utilities Commission of Nevada.

115. In re: Petition for Order Concerning Delineation of Transmission and Local Distribution Facilities, Docket No. 98-0894 on behalf of The City of Chicago, before the Illinois Commission in reference to re-functionalization.

116. In re: Consolidated Edison Company, Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for the breach of contract to provide firm service on a non-discriminatory basis.

117. In re: Wisconsin Public Power, Inc. Docket No. 05-EI-119 on behalf of Wisconsin Transmission Customer Group (WTCG"), before the Public Service Commission of Wisconsin to address the concerns of municipally-owned utilities within Wisconsin.

UTILICORP UNITED
DOCKET NO. EM-2000-369
DATA REQUEST NO. EDSPR-24

DATE OF REQUEST: January 20, 2000

DATE RECEIVED: January 20, 2000

DATE DUE: February 8, 2000

REQUESTOR: Jeff Keevil

QUESTION:

Please indicate the extent to which the merger(s) will require Applicants to reserve firm transmission capacity on the transmission systems owned by Applicants or others in order to conduct integrated operations. Please provide all documents related to, arising from or used in connection with Applicants' consideration of the type (network or point-to-point) of transmission service they will need to integrate their operations and the characteristics of the transmission capacity for which reservations have already been obtained or applied for.

RESPONSE: The Study by SPP has been requested. Expect results in 2 to 3 months

ATTACHMENTS: None

ANSWERED BY: John McKinney

UTILICORP UNITED
DOCKET NO. EM-2000-369
DATA REQUEST NO. EDSPR-24

Supplemental 24

DATE OF REQUEST: January 20, 2000

DATE RECEIVED: January 20, 2000

DATE DUE: February 8, 2000

REQUESTOR: Jeff Keevil

QUESTION:

Please indicate the extent to which the merger(s) will require Applicants to reserve firm transmission capacity on the transmission systems owned by Applicants or others in order to conduct integrated operations. Please provide all documents related to, arising from or used in connection with Applicants' consideration of the type (network or point-to-point) of transmission service they will need to integrate their operations and the characteristics of the transmission capacity for which reservations have already been obtained or applied for.

RESPONSE:

Application for SPP Network Integration Transmission Service is attached

ATTACHMENTS:

Application for SPP Network Integration Transmission Service

ANSWERED BY:

David Macey

1 CD incl

APPLICATION FOR SPP NETWORK SERVICE

Applicant:	UtiliCorp United Inc. 10700 E. 350 Hwy Kansas City, MO 64138
Contact:	David A. Macey
Phone:	816-737-7519
FAX:	816-737-7630
E-Mail	dmacey@utilicorp.com

UtiliCorp United Inc. (UCU) is hereby submitting an application for Network Transmission Service from the Southwest Power Pool (SPP). In accordance with Section 29.2 of the SPP Open Access Transmission Tariff (Tariff) UCU hereby states that it is an Eligible Customer in accordance with Section 1.11 of the Tariff.

Delivery Points:

UCU is requesting SPP Network Transmission Service for the native load in the following existing control areas:

- Missouri Public Service (MPS)
- WestPlains Energy-Kansas (WPEK)
- Empire District Electric (EDE)
- St. Joseph Light and Power (SJLP)

The delivery points for each of the control areas are shown on the attached Table 5 through Table 8.

Interruptible Loads:

To be provided.

Network Resources:

Tables 1 through Table 4 show the network resources and loads for the next 10 years for each of the existing control areas.

Description of Transmission System:

Transmission planning models are prepared annually by the SPP Model Development Working Group. All real and reactive components of the loads, lines, transformers, and generation for the four control areas listed above are represented in these models. Also represented are the normal and emergency ratings of all lines, equipment, and interconnections. Models are prepared for a number of years and seasons over a 10 year planning horizon. Proposed transmission expansions and upgrades are shown in these various models.

Various operating guides are on file with the SPP.

For reliability reasons, both the Cimarron River Station and the Judson Large Station in the WPE control area are required to run during summer peak load conditions.

Service Commencement:

UCU is requesting that Network Transmission Service should begin on October 1, 2000 and extend to September 30, 2010.

Revised 1/27/00

Table 1
MPS
Loads and Resources Forecast

A. System Generation Capacity		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity													
MPS Sibley 1	Coal	53	53	53	53	53	53	53	53	53	53	53	53
MPS Sibley 2	Coal	53	53	53	53	53	53	53	53	53	53	53	53
MPS Sibley 3	Coal	395	395	395	410	410	410	410	410	410	410	410	410
MPS Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59	59	59
MPS Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58	58	58
Total Base Capacity		677	677	677	692	692	692	692	692	692	692	692	692
MPS Ralph Green 3	Gas	74	74	74	74	74	74	74	74	74	74	74	74
MPS Greenwood 1	Gas	62	62	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 2	Gas	62	62	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 3	Gas	62	62	67	67	67	67	67	67	67	67	67	67
MPS Greenwood 4	Gas	61	63	66	66	66	66	66	66	66	66	66	66
MPS Nevada	Oil	20	20	20	20	20	20	20	20	20	20	20	20
MPS TWA 1	Oil	15	15	18	18	18	18	18	18	18	18	18	18
MPS TWA 2	Oil	18	18	18	18	18	18	18	18	18	18	18	18
Total Int/Peaking Capacity		374	376	397	397	397	397	397	397	397	397	397	397
Grand Total		1051	1053	1074	1089	1089	1089	1089	1089	1089	1089	1089	1089
Changes in Existing Capacity		2	18	15	0	0	0	0	0	0	0	0	0
New Generation Capacity		0	0	0	0	0	0	0	0	0	0	0	0
Total Generation Capacity		1053	1071	1089	1089	1089	1089	1089	1089	1089	1089	1089	1089

B. Capacity Transactions	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases												
MPS Associated Electric Coop	190	0	0	0	0	0	0	0	0	0	0	0
MPS Kansas City Power & Light	90	0	0.	0	0	0	0	0	0	0	0	0
MPS WPEKS	50	115	55	0	0	0	0	0	0	0	0	0
MPS PGET	50											
MPS Aquila Power		135										
MPS KC BPU	0	92										
MPS AMEP	0	0	320	500	500	500	0	0	0	0	0	0
MPS CT Purchase #4								160	160	160	160	160
MPS CT Purchase #7											160	160
MPS CC Purchase #1							250	250	250	250	250	250
MPS CC Purchase #1A							250	250	250	250	250	250
MPS Short Term Purch #1						10	60		5	60		10
Total Purchases	380	342	375	500	500	510	560	660	665	720	820	830
Sales												
MPS Tenaska	50											
MPS Colby	4											
Total Sales	[illegible]	[illegible]	[illegible]									

Table 1
MPS
Loads and Resources Forecast

Net Transactions	326	342	375	500	500	510	560	660	665	720	820	830
Total System Capacity (A+B)	1379	1413	1464	1589	1589	1599	1649	1749	1754	1809	1909	1919
C. System Peaks & Reserves	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands												
Actual Peak												
Forecasted Peak	1213	1247	1286	1325	1366	1409	1453	1498	1545	1593	1643	1694
DSM	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Peak Forecast with DSM	1208	1242	1281	1320	1361	1404	1448	1493	1540	1588	1638	1689
Capacity Reserves (A+B-C)	171	171	183	269	228	195	201	256	214	221	271	230
D. Capacity Needs	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves												
MPS Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1373	1411	1456	1500	1547	1595	1645	1697	1750	1805	1861	1919
Capacity Balance (A+B-D)	6	2	8	89	42	4	4	52	4	4	48	(0)

Table 2
WestPlains Energy - Kansas
Loads and Resources Forecast

A. System Generation Capacity		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity													
Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59	59	59
Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59	59	59
Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58	58	58
Total Base Capacity		176	176	176	176	176	176	176	176	176	176	176	176
JLS	Gas	143	143	143	143	143	143	143	143	143	143	143	143
AMS	Gas	90	90	90	90	90	90	90	90	90	90	90	90
CRS #1	Gas	58	58	58	58	58	58	58	58	58	58	58	58
CRS #2	Gas	14	14	14	14	14	14	14	14	14	14	14	14
Clifton #1	Gas	71	71	71	71	71	71	71	71	71	71	71	71
Clifton #2	Oil	2	2	2	2	2	2	2	2	2	2	2	2
Total Int/Peaking Capacity		378	378	378	378	378	378	378	378	378	378	378	378
Grand Total		554	554	554	554	554	554	554	554	554	554	554	554
Changes in Existing Capacity		0	0	0	0	0	0	0	0	0	0	0	0
New Generation Capacity		0	0	0	0	0	0	0	0	0	0	0	0
Total Generation Capacity		554	554	554	554	554	554	554	554	554	554	554	554
B. Capacity Transactions		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases													
Sunflower #1		100	160	150	140	130	120	0	0	0	0	1	2
Sunflower #2		25											
Municipals		79	79										
Total Purchases		204	239	150	140	130	120	0	0	0	0	1	2
Sales													
Russell & Beloit		7	6	6	3	3	3						
KEPCO		3	3	3	3	3	3	3	3	3	3	3	3
MPS		50	85	50			15						
Colby													
Total Sales		60	94	59	6	6	21	3	3	3	3	3	3
Net Transactions		144	145	91	134	124	99	(3)	(3)	(3)	(3)	0	0
Total System Capacity (A+B)		698	699	645	688	678	653	551	551	551	551	554	554
C. System Peaks & Reserves		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands													
Actual Peak													

Table 2
WestPlains Energy - Kansas
Loads and Resources Forecast

A. System Generation Capacity		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity													
Jeffrey EC 1	Coal	59	59	59	59	59	59	59	59	59	59	59	59
Jeffrey EC 2	Coal	59	59	59	59	59	59	59	59	59	59	59	59
Jeffrey EC 3	Coal	58	58	58	58	58	58	58	58	58	58	58	58
Total Base Capacity		176	176	176	176	176	176	176	176	176	176	176	176
JLS	Gas	143	143	143	143	143	143	143	143	143	143	143	143
AMS	Gas	90	90	90	90	90	90	90	90	90	90	90	90
CRS #1	Gas	58	58	58	58	58	58	58	58	58	58	58	58
CRS #2	Gas	14	14	14	14	14	14	14	14	14	14	14	14
Clifton #1	Gas	71	71	71	71	71	71	71	71	71	71	71	71
Clifton #2	Oil	2	2	2	2	2	2	2	2	2	2	2	2
Total Int/Peaking Capacity		378	378	378	378	378	378	378	378	378	378	378	378
Grand Total		554	554	554	554	554	554	554	554	554	554	554	554
Changes in Existing Capacity		0	0	0	0	0	0	0	0	0	0	0	0
New Generation Capacity		0	0	0	0	0	0	0	0	0	0	0	0
Total Generation Capacity		**554**	**554**	**554**	**554**	**554**	**554**	**554**	**554**	**554**	**554**	**554**	**554**

B. Capacity Transactions	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases												
Sunflower #1	100	160	150	140	130	120	0	0	0	0	1	2
Sunflower #2	25											
Municipals	79	79										
Total Purchases	204	239	150	140	130	120	0	0	0	0	1	2
Sales												
Russell & Beloit	7	6	6	3	3	3						
KEPCO	3	3	3	3	3	3	3	3	3	3	3	3
MPS	50	85	50			15						
Colby												
Total Sales	60	94	59	6	6	21	3	3	3	3	3	3
Net Transactions	144	145	91	134	124	99	(3)	(3)	(3)	(3)	0	0
Total System Capacity (A+B)	698	699	645	688	678	653	551	551	551	551	554	554

C. System Peaks & Reserves	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands												
Actual Peak												

Table 3
SJLP
Loads and Resources Forecast

A. System Generation Capacity			1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity														
SJLP	Iatan Share	Coal	121	121	121	121	121	121	121	121	121	121	121	121
SJLP	Lake Rd #4	Coal	97	97	97	97	97	97	97	97	97	97	97	97
Total Base Capacity			218	218	218	218	218	218	218	218	218	218	218	218
SJLP	Lake Rd #1	Gas	22	22	22	22	22	22	22	22	22	22	22	22
SJLP	Lake Rd #2	Coal	27	27	27	27	27	27	27	27	27	27	27	27
SJLP	Lake Rd #3	Gas	11	11	11	11	11	11	11	11	11	11	11	11
SJLP	Lake Rd CT	Gas	63	63	63	63	63	63	63	63	63	63	63	63
SJLP	Lake Rd JE	Oil	42	42	42	42	42	42	42	42	42	42	42	42
Total Int/Peaking Capacity			165	165	165	165	165	165	165	165	165	165	165	165
Grand Total			383	383	383	383	383	383	383	383	383	383	383	383
Changes in Existing Capacity			0	0	0	0	0	0	0	0	0	0	0	0
New Generation Capacity			0	0	0	0	0	0	0	0	0	0	0	0
Total Generation Capacity			383	383	383	383	383	383	383	383	383	383	383	383

B. Capacity Transactions		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases													
SJLP	NPPD	25	60	70	80	90	100	100	100	100	100	100	100
SJLP	KCPL	35											
SJLP	MEC	5											
SJLP	Shrt Trm Purch #3		10	10	10	10	10	20	30	45	55	65	75
Total Purchases		65	70	80	90	100	110	120	130	145	155	165	175
Sales													
SJLP	Steam Capacity	5	5	5	5	5	5	5	5	5	5	5	5
Total Sales		5	5	5	5	5	5	5	5	5	5	5	5
Net Transactions		60	65	75	85	95	105	115	125	140	150	160	170
Total System Capacity (A+B)		443	448	458	468	478	488	498	508	523	533	543	553

C. System Peaks & Reserves	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands												
Actual Peak												
Forecasted Peak	379	388	397	403	413	422	432	442	452	461	471	481
DSM	0	0	0	0	0	0	0	0	0	0	0	0
Peak Forecast with DSM	379	388	397	403	413	422	432	442	452	461	471	481
Capacity Reserves (A+B-C)	64	60	61	65	65	66	66	66	71	72	72	72

D. Capacity Needs	1999	2000	[illegible]	2002	2003	2004	2005	2006	2007	2008	2009	2010

Table 3
SJLP
Loads and Resources Forecast

Capacity Reserves												
Capacity Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
Required Capacity	436	446	457	463	475	485	497	508	520	530	542	553
Capacity Balance (A+B-D)	7	2	1	5	3	3	1	(0)	3	3	1	(0)

Table 4
EDE
Loads and Resources Forecast

C. System Peaks & Reserves	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Peak Demands												
Actual Peak												
Forecasted Peak	956	975	993	1010	1028	1044	1061	1077	1094	1110	1124	1139
DSM	14	14	14	14	14	14	14	14	14	14	14	14
Peak Forecast with DSM	942	961	979	996	1014	1030	1047	1063	1080	1096	1110	1125
Capacity Reserves (A+B-C)	141	154	209	192	174	158	146	145	148	152	153	201

D. Capacity Needs	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Capacity Reserves												
Capacity Margin	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
Required Capacity	1070	1092	1113	1132	1152	1170	1190	1208	1227	1245	1261	1278
Capacity Balance (A+B-D)	13	23	76	56	38	18	3	0	1	3	2	48

Table 5
Missouri Public Service SPP PODs

FROM SPP			TO MPS POD			Normal	Emergency	SPP
Bus No.	Name	Voltage	Bus No.	Name	Voltage	Rating	Rating	Trans. Prov.
7668	STILWEL7	345	7500	PHILL 7	345	721	721	KCPL
7672	HAWTH 7	345	7501	SIBLEY 7	345	721	721	KCPL
7728	NASHUA 5	161	7503	NASHUA 5	161	335	335	KCPL
7669	STILWEL5	161	7507	ARCHIE 5	161	224	224	KCPL
7695	MONTROS5	161	7507	ARCHIE 5	161	224	224	KCPL
7693	STHTOWN5	161	7510	MARTCTY5	161	224	224	KCPL
7702	MARTCTY5	161	7510	MARTCTY5	161	293	335	KCPL
7719	BARRY 5	161	7530	RNRIDGE5	161	293	335	KCPL
7726	TIFFANY5	161	7530	RNRIDGE5	161	293	335	KCPL
7728	NASHUA 5	161	7530	RNRIDGE5	161	293	335	KCPL
6608	STRANGR7	345	7531	STRANGR5	161	400	440	WR
7781	GLENARE2	69	7562	LIBERTY2	69	66	66	KCPL
7796	MAYVWTP2	69	7565	LEXNTON2	69	100	107	KCPL
7796	MAYVWTP2	69	7566	13&40 2	69	100	107	KCPL

Table 6
WestPlains Energy SPP PODs

FROM SPP			TO WPEK POD			Normal	Emergency	SPP
Bus No.	Name	Voltage	Bus No.	Name	Voltage	Rating	Rating	Trans. Owner
6637	CIRCLE 6	230	7379	MULGREN6	230	319	319	WR
6638	EMANHAT6	230	7358	CONCORD6	230	319	319	WR
6713	GILL 4	138	7375	MILANTP4	138	101	108	WR
6849	KNOB HL3	115	7365	GRNLEAF3	115	84	90	WR
6912	ST JOHN3	115	7396	ST-JOHN3	115	84	90	WR
6301	HEIZER 3	115	7739	MULGREN6	230	142	142	MIDW

Table 7
St. Joseph Light & Power SPP PODs

FROM SPP			TO SJLP POD			Normal	Emergency	SPP
Bus No.	Name	Voltage	Bus No.	Name	Voltage	Rating	Rating	Trans. Prov.
7672	HAWTH 7	345	69702	ST JOE 3	345	956	956	KCPL
7682	IATAN 7	345	69702	ST JOE 3	345	956	956	KCPL
7728	NASHUA 5	161	69705	LAKE RD5	161	153	172	KCPL

Sched

Table 8
Empire District Electric SPP PODs

FROM SPP			TO EDE POD			Normal	Emergency	SPP
Bus No.	Name	Voltage	Bus No.	Name	Voltage	Rating	Rating	Trans. Prov.
8620	BRKLNE 7	345	8207	MON383 7	345	951	1195	SPFLD
2948	TABLE R5	161	8223	RVS438 5	161	218	268	SWPA
2962	NEO SPA5	161	8197	NEO184 5	161	130	157	SWPA
2962	NEO SPA5	161	8198	TIP292 5	161	130	157	SWPA
2964	CARTHAG5	161	8192	ATL109 5	161	175	214	SWPA
2964	CARTHAG5	161	8205	LAR382 5	161	189	189	SWPA
2964	CARTHAG5	161	8211	CAR395 5	161	218	268	SWPA
2968	SPRGFLD5	161	8205	LAR382 5	161	167	167	SWPA
3139	FLINTCR5	161	8210	DEC392 5	161	218	268	CSW
3140	FLINTCR7	345	8207	MON383 7	345	1056	1186	CSW
3960	GROVE 5	161	8222	NOL435 5	161	218	268	CSW
3966	VINTAJC4	138	8212	HOC404 4	138	191	210	CSW
4431	MIAMI 5	161	8213	HOC404 5	161	225	267	GRDA
4508	FAIRTAP2	69	8309	FRL363 2	69	64	80	GRDA
6654	LITCH 5	161	8202	ASB349 5	161	211	211	WR
6658	NEOSHO 5	161	8191	COL 94 5	161	255	281	WR

ST. JOSEPH LIGHT & POWER COMPANY/UTILICORP INC.
EM-2000-292
Data Request
of
Ag Processing Inc
to
Joint Applicants

December 23, 1999

Item No.	Description
54.	Please provide all workpapers and supporting documentation, including models employed, supporting the testimony and exhibits of Robert Holzwarth.

See Attached

RECEIVED
FEB 28 2000
CHITFIELD RUSSELL ASSOCIATES

The attached or above information provided to the requesting party or parties in response to this data or information request is accurate and complete and contains no material misrepresentations or omissions, based upon present facts to the best of the knowledge, information or belief of the undersigned. The undersigned agrees to immediately inform the requesting party or parties if during the pendency of this case any matters are discovered which would materially affect the accuracy or completeness of the attached information and agrees to regard this as a continuing data request.

As used in this request the term "document" includes publications in any format, work papers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data recordings, transcriptions and printer, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to the party to whom this request is tendered and named above and includes its employees, contractors, agents or others employed by or acting in its behalf.

Signed: [signature]

Date: 1-10-00

Sedina Eric

From: Sedina Eric <SEric@wrassoc.com>
To: Gary Clemens <gclemens@utilicorp.com>
Cc: Steve Flanagan <SFlanagan@WRAssoc.com>; Whitfield Russell <WRussell@WRAssoc.com>; Jeff Keevil <PER594@aol.com>
Sent: Thursday, March 16, 2000 3:01 PM
Subject: Additional Information-Docket No. EM-2000-369

Docket No. EM-2000-369

Dear Mr. Clemens,

Would you please provide the following additional information we need:

1. With respect to the Data Request No. EDSPR-28 you provided the files in GE format as described in your filekey.txt files. Please provide this files in PTI PSS/E format if possible. If not, please provide the input-raw files that match the saved files you have already provided in GE format.

2. Please provide data on dispatch of the generating units in UtilCorp United, Inc. Misouri Public Service, WestPlains Energy-Kansas, WestPlains Energy-Colorado, St. Joseph Light and Power Co., and Empire District Electric Co. as it is planned for the post merger cases for 2000 and 2001 summer peak, normal and north to south heavy transfer conditions.

3. Please provide the information (MW, source and sink) on all purchases and sales of power to and from merged companies in the post-merger case, that will result in a re-dispatch of generation in systems outside the merged companies. This should match the cases 2000 and 2001 summer peak, normal and north to south heavy transfer conditions.

4. With respect to Data Request EDSPR-34 please identify the heavy north to south transfer: source and sink, and the additional amount of power transferred compared to the 2000 and 2001 summer peak normal base case.

Thank you for the switching maps you mailed to us. If you have any question, please call me at 202 371-8200.

Sincerely,

Sedina Eric

Whitfield Russell Associates
Phone: 202 371-8200
SEric@WRAssoc.com

UtilCorp sent on 3/28/00

Exhibit WAR-01

WR
MJ
J+
SA
SE
+1 CD

Dear Mr. Clemens,

Would you please provide the following additional information we need:

1. With respect to the Data Request No. EDSPR-28 you provided the files in GE format as described in your filekey.txt files. Please provide this files in PTI PSS/E format if possible. If not, please provide the input-raw files that match the saved files you have already provided in GE format.

Requested files are included in PTI format on the enclosed CD. Files are arranged and named as previously supplied in GE format. These PTI files were created using the GE program and saving the files in PTI format. Because UCU does not use the PTI/PSSE program, the integrity of the files supplied in PTI format cannot be verified.

2. Please provide data on dispatch of the generating units in UtilCorp United, Inc. Misouri Public Service, WestPlains Energy-Kansas, WestPlains Energy-Colorado, St. Joseph Light and Power Co., and Empire District Electric Co. as it is planned for the post merger cases for 2000 and 2001 summer peak, normal and north to south heavy transfer conditions. <?xml:namespace prefix = o ns = "urn:schemas-microsoft-com:office:office" />

For summer peak conditions, the expected post-merger dispatch will not change significantly compared to the pre-merger dispatch in the provided cases.

3. Please provide the information (MW, source and sink) on all purchases and sales of power to and from merged companies in the post-merger case, that will result in a re-dispatch of generation in systems outside the merged companies. This should match the cases 2000 and 2001 summer peak, normal and north to south heavy transfer conditions.

Neglecting changes in power purchases and transmission losses, there are no known purchases or sales within the post-merger company that would result in a redispatch of generation in systems outside the merged companies. Purchases by the merged company to serve native load will generally decrease due to more efficient use of the merged company's generation resources. The reduction in purchases could reduce the generation levels as well as transmission losses in the selling systems if those systems are not able to find other markets for their energy.

4. With respect to Data Request EDSPR-34 please identify the heavy north to south transfer: source and sink, and the additional amount of power transferred compared to the 2000 and 2001 summer peak normal base case.

St. Joseph L&P (2000 Summer Peak heavy transfer)

** Start of Response to Item 4**

The Heavy North - South scenario was modeled after the MINT ATC study performed by SJLP. Generation in the North was increased by 2,316 MW. Generation in the South was decreased by 1,979 MW. The difference is due to losses on the system. Except where noted, generation was scaled by the same percentage on all generators (that were on in the model) within the area.

The following areas were increased in the North (using the increment scale command in PSLF) with their MW increase shown in parenthesis.

NPPD (311 MW) area 602
OPPD (88 MW) area 603
LES (153 MW) area 604

WAPA (406 MW) area 606
OTP (151 MW) area 614
SMMPA (92 MW) area 619
MP (229 MW) area 621
UPA (107 MW) area 622
NSP (604 MW) area 623
IPW - Fox Lake Station (38 MW) area 625 busses 67455-67457
MEC area 630
Sycamore (79 MW) bus 62426
River Hill (58 MW) buses 62452-62453

The following areas were decreased in the South (using the increment scale command in PSLF) with their MW decrease shown in parenthesis.

UE area 356
Labadie (250 MW) bus 30894
Sioux (104 MW) bus 31756
Rush Island (80 MW) bus 31670
Meramec (38 MW) bus 31132
WERE (472 MW) area 36
MPS (133 MW) area 40
EDE (105 MW) area 44
AEC (403 MW) area 130
SPR (94 MW) area 46
KCPL (except Hawthorn) (273 MW) area 41
SJLP (27 MW) area 679

Then Pnet Schedule for each area was adjusted in the edit area table by the above amounts for each area. Then the Pnet Schedule was adjusted again for each area to account for the losses. Every area (both those with increases and decreases) had Pnet Schedule adjusted to account for losses. This was accomplished by adjusting each according to its percentage divided by 2 (2 sets that added to 100%).

The Sidney - Keystone line reactor was turned off. The DC converters at bus 61503 were adjusted to a schedule of 525 MW to get the case to solve.

** End of Response to Item 4 **

Dennis,

With respect to our phone call of March 21, 2000 please provide the data we requested on our original data request No EDSPR-28:

> *EDSPR-28 Please provide power system databases for the years 1999, and 2001, peak and off-peak, in PSS/E electronic format of the SPP transmission system, with more detailed modeling of the UtiliCorp United, Inc. Missouri Public Service, St. Joseph Light & Power Co, and Empire District Electric Co. transmission systems. In addition please provide all power flow databases used by the Applicants in any modeling conducted to simulate power flows resulting from the combined operation of the Applicants' systems. [If this data is not available in the specified format, please provide it in whichever format is available and specify the format provided.]*

You previously provided a CD containing the load flow files organized in a three subdirectories: SJLP, EDE, and SPP-PSSE.

The first two subdirectories SJLP and EDE, contain key files describing each file base case. These base cases simulate the interconnection options, but none of them simulate the combined operation of all the Applicants.

The 1999 cases under the SPP-PSSE subdirectory contained the files identical to the SPP files filed with the SPP FERC Form 715 in April of 1999.

Please clarify if the 2001 base case files under the SPP-PSSE subdirectory simulate post merger conditions. If not, we are reiterating our original request that you provide the load flow base cases that simulate post-merger conditions for 2001. Please provide these cases in the PSS/E raw format. This data should reflect the re-dispatch of the combined system to serve native loads and any off-system sales and purchases that reflect the estimated combined system operation benefits that the Applicants claimed in their merger filings.

<u>For the purposes of transmission system analysis in the SJLP and EDE interconnection studies, UCU did not vary the post-merger dispatch from the pre-merger dispatch. For transmission system analysis only, the expected post-merger dispatch can be adequately represented using the pre-merger dispatch in the provided cases.</u>

Thanks

Sedina Eric
Whitfield Russell Associates

TLR Curtailments

Requester: MAPP

Flowgate: FtCal_S Flgt# 6014

Date: 03/04/00 0738

END TIME: 1218

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
MEC	MPS	1-NS	50	50	800	MEC_RESEE0003935_MPS	
WAUE	MPS	2-NH	75	25	0800	WAUE_UCUMO0004094_MPS	

TLR Curtailments

Requester: SPP

Flowgate:Albany 161/138 transformer

Date: 01/28/2000 0600cst

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
MPW	MPS	ND-3	50	50	600	MPW_EPMIEA003220_MPS	

TLR Curtailments

Requester: SPP

Flowgate:EAU CLAIRE-ARPIN 345

Date: 11/17/99 AT 0600

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	2-NH	46	8	600	WAUE_UCUMO0001278_MPS	

TLR Curtailments

Requester: SPP

Flowgate:COOPER-S

Date: 10/31/99 AT 0741

END TIME: 1633

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
EES	EDE	1-NS	50	1	800	EES_EPMCO010001325_EDE	900
EES	EDE	1-NS	49	16	900	EES_EPMCO10001356_EDE	1800

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/22/99 AT 1430

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	4-NW	100	100	1500	WAUE_UCUMO0000714_MPS	
WAUE	MPS	5-NM	100	14	1500	WAUE_UCUMO0000713_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/21/99 AT 1906

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	5-NM	87	55	1930	WAUE_UCUMO0000704_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/21/99 AT 1641

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	4-NW	3	3	1700	WAUE_UCUMO0000705_MPS	
WAUE	MPS	5-NM	100	12	1700	WAUE_UCUMO0000704_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/21/99 AT 1535

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	4-NW	83	79	1600	WAUE_UCUMO0000705_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/21/99 AT 1445

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	4-NW	100	16	1500	WAUE_UCUMO0000705_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/21/99 AT 1142

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	4-NW	100	36	1200	WAUE_UCUMO0000705_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/20/99 AT 1640

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
SJLP	MPS	2-NH	10	10	1700	SJLP_UCUMO0000694_MPS	
SJLP	MPS	2-NH	10	10	1700	SJLP_UCUMO0000706_MPS	
WAUE	MPS	4-NW	100	76	1700	WAUE_UCUKO0000687_MPS	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/19/99 AT 0520

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

FROM	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
WAUE	MPS	3-ND	90	90	600	WAUE_UCUMO0000671_MPS	
WAUE	MPS	3-ND	100	100	600	WAUE_UCUMO0000620_MPS	
WAUE	MPS	4-NW	97	97	600	WAUE_UCUMO0000608_MPS	