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Before the Public Service Commission Of the State of Missouri

In the Matter of the Joint Application of UtiliCorp United Inc. and St Joseph Light & Power Company for Authority to Merge St. Joseph Light & Power Company with and Into UtiliCorp United Inc., and in Connection Therewith, Certain Other Related Transactions	**) Case No. EM-2000-292**

REBUTTAL TESTIMONY OF

WHITFIELD A. RUSSELL

On Behalf Of
Springfield (MO) City Utilities

May 1, 2000

Before the Public Service Commission
Of the
State of Missouri

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UtiliCorp United Inc. and St Joseph Light &	)	
Power Company for Authority to Merge St.	)	
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TABLE OF CONTENTS

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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 St. Joseph Light & Power Company ("St. Joseph L&P" or "SJPL") 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 Empire District Electric Company ("Empire", "EMDE" or "EDE") 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 even bothered to fully evaluate 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, however, 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. Such merger-related suppression of wholesale competition will be reflected in increased 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 MoPub 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 four pockets of load and generation.[1] This has significant consequences to the State of Missouri. Under a literal interpretation of industry curtailment rules, MoPub could arguably call for transmission loading relief ("TLR") when it experiences transmission overloads and thereby call a halt to north-to-south transfers needed by other Missouri utilities to lower their costs. In some cases, UtiliCorp might have reason to ask 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.

For example, as part of this merger, Applicants set out a plan to build (but make no 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 Company ("KCPL") transmission system, through which much of the electricity 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.

On the other hand, failure to construct facilities needed to support post-merger operations can result in a degradation of service to all Missouri ratepayers. In the related merger involving UtiliCorp and Empire District, Applicants have set out a plan to build a 161 kV line from Nevada (UtiliCorp) to Asbury (Empire) that 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 either. Thus, testimony in the two related UtiliCorp merger proceedings provide examples of plans to build both needed lines and unneeded lines. For reasons that are related little - if at all - to reliability, Applicants show enthusiasm for building the unneeded line but have made no commitment to build either line.

Curtailments and interruptions that could result in 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 on wholesale markets flow directly to retail users.

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. Wholesale purchase opportunities avoid the need for higher-cost generation additions. Wholesale sale opportunities ordinarily result in revenue credits in retail rate cases, minimizing the portion of the revenue requirement that must be recovered from retail customers. Vigorous wholesale competition is also a necessary predicate to the retail competition this State may consider in the future.

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

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. Otherwise, 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, ensuring adequacy 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. Schedule RCK-10 is a study examining the options for physically connecting UtiliCorp to SJLP, 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, under the guise of integrating the operations of UtiliCorp and SJLP, UtiliCorp is seeking to build transmission facilities to evade support of the KCPL transmission system and to gain low-cost access (or no-cost access) to retail customers now served by KCPL, if retail access becomes a reality. KCPL's service area lies between the service areas of SJLP and of UtiliCorp's Missouri Public Service Company ("MoPub" or "MIPS"). Unless they build their own physical interconnection through KCPL's service area, MoPub and SJLP would likely be dependent upon use of KCPL's transmission system to integrate their operations, and would not have a direct entry to KCPL customers upon the advent of retail access.

Second, the study in Schedule RCK-10 analyzes numerous alternatives for interconnecting the merging companies of which only one involves use of transmission service, and that analysis is done in a manner that is biased against the transmission service option. It appears that all alternatives other than transmission service involve a physical interconnection between UtiliCorp and SJLP routed through the service area of KCPL and include newly constructed and/or newly acquired transmission facilities. Applicants propose to build their own 161 kV line and to disconnect from KCPL's existing line (possibly leading to abandonment and/or dismantling of the KCPL line). Even though buying transmission service from KCPL is relatively inexpensive ($0.88 per kW-month), Applicants boost the cost of that option by evaluating it over a 30-year period such that its cost is inflated even though the 30-year stream of transmission payments is discounted in making the comparison. And it is not clear that the life-cycle cost of operations and maintenance is included in the "build option".

I recognize that the life-cycle cost of a new transmission line should be compared to the cost of transmission service over an appropriate time period, but the only time period selected for comparison in the study is one that disfavors transmission service and undervalues its flexibility. That is, transmission service is much more flexible than construction of new transmission lines in that transmission service can be taken for one year or five years while awaiting the evolution of ISOs and RTOs. By comparison, a transmission line has an economic life of 30 years or more. Thus, the up-front capital outlay for new transmission facilities is the same for one year or five years as it is for 30 years.

Third, absent construction of its own physical interconnection, UtiliCorp will have to pay KCPL to provide transmission service between Missouri Public Service and SJLP. A physical interconnection will create a contract path that will eliminate the need to pay for transmission service, even if some of the power still flows over the KCPL system. Although avoided payments for transmission service may represent a saving to UtiliCorp, they represent an increase in costs to KCPL ratepayers (who lose the associated revenue credits), and represent a negative for society as a whole. There is a detrimental effect on the environment from constructing an unnecessary transmission line, and a detrimental effect if the KCPL line goes underutilized, is abandoned or is dismantled. The plan preferred by Applicants is not likely to be one that an ISO would adopt in seeking to optimize the regional transmission system. And if Applicants build the proposed line and they and KCPL later join the same ISO, the damage could not be undone. The ISO's transmission rates will be unnecessarily inflated if both the existing and new lines between Lake Road and Nashua later become part of an ISO.

Fourth, Applicants assert that the existing KCPL 161 kV line connecting SJLP's Lake Road generating to KCPL's Nashua Substation (near MoPub's Nashua Substation) is unreliable but is an important feed into Lake Road and the St. Joseph load center. Yet Applicants' studies demonstrate that whether it is purchased from KCPL and upgraded or replaced by Applicants' own 161 kV line, that line remains overloaded and has to be taken out of service under heavy transfer conditions. None of the 161 kV alternatives solves the significant existing reliability problem Applicants have identified, nor does transmission service from KCPL.

Fifth, it appears that Applicants have proposed to build their own 161 kV line and to disconnect from KCPL's existing line (possibly leading to its abandonment and dismantling) in an effort to induce KCPL to sell its existing line to Applicants for a reasonable price. Applicants present no analysis of an obvious alternative that mitigates the reliability problem: constructing and operating their new line in parallel with KCPL's existing line. Parallelling the two lines would increase their transfer capability and lower their impedances.

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. That is, Applicants' preferred transmission alternative (Option 2-B, the new Lake Road South to Nashua-MPS 161 kV line described at page 12 of Mr. Kreul's Schedule RCK-10)[2] would be a new line routed through the service area of KCPL in parallel with the KCPL line.

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

[2] Schedule RCK-10 is an incomplete document. It is a 21-page exhibit that makes reference to tables on pages 37 and page 38 that are not included in the Schedule.

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, the 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 MPSC and the Commission itself are deeply involved in the planning processes of utilities, ISOs and 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. 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.

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

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 when applied at retail, 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/St. Joseph L&P 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 transmission 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 for purposes of servicing "native load" – i.e., a utility's bundled retail customers. Native load priorities can be invoked by transmission owners 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 SJLP and EDE, 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 four separate control areas, even if all four of those control areas are not integrated operationally. 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, the Applicants might move power from one of their four 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 four 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 and curtailing non-firm network transmission service. This merely confirms the Applicants' offer to waive their priorities under AES v. 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.

II. 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. 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 four 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 reservation, scheduling and monitoring requirements (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 four separate control areas into one. Consolidation of control areas would transform what are now (a) pre-scheduled and 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, tagging and 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 unloaded transmission capacity must be left unloaded 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. The high likelihood that the merger will reduce firm ATC is important in that Applicants' study of market power assumes that there will be no

[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.

change in ATC as a result of the merger. Indeed, their transmission studies assume no change in internal dispatch of their four separate pockets of load and generation.

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 and curtailment requirements of the OATT and not be reported on the OASIS of the transmission owner or of any ISO or RTO in which it participates. 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 to reserve transmission capacity on the relevant OASIS for purposes of carrying out any internal dispatch between what are now four geographically isolated pockets of load and generation in four separate control areas of the merging companies, to implement real-time monitoring of intra-company flows associated with internal dispatch, to report continuously the amount of such flows on its OASIS and to make all reasonable efforts to limit internal dispatch to levels at or below the transmission capacity reserved for purposes of carrying it out. 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 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.

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. From Missouri's point of view, the integration of transmission facilities under a regional transmission organization is far more important because it will identify and protect against potential abuses likely to flow from Applicants' plan to integrate their generation. Mr. Kreul's testimony (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 three separate ISOs (MAPP, SPP and MidWest). St. Joseph L&P operates as part of the Mid America Power Pool ("MAPP"). UtiliCorp has 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 strategems (and some not so subtle) in order to frustrate the separation of functions and to deny transmission access.

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

Although FERC's Order No. 2000 recognizes its authority to require RTO participation in certain circumstances, it is seeking to promote voluntary RTO formation. This Commission should be concerned about the manner in which Missouri utilities carve up the state into multiple RTOs that may enhance their marketing advantage, 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 UtiliCorp has requested network service from the SPP ISO. Although the Midwest ISO is arguably feasible, it will introduce a fourth ISO into Missouri. And the benefits of participation in the Midwest ISO may ultimately be realized through a merger of the Midwest and SPP ISOs.

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

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. 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.

However, Applicants have made it clear that they have not committed to construct any of the facilities they modeled. They assert 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 have 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 page 11, line 26-page 12, line 13. As I discussed earlier, one of those additional transmission facilities serves a demonstrable need whereas one other does not.

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, Applicants have indicated:

1. That such a study will be conducted by SPP,
2. That such a study has not yet been conducted,
3. That it will take two to three months to complete and
4. That the planned SPP study resulted from an application for SPP network service. See UtiliCorp's response to Springfield's data request No. EDSPR-24. UtiliCorp revised that application on January 27, 2000. Schedule__(WAR-2).

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

A. No, for reasons that I discuss later in this testimony in connection with the need for a commitment from Applicants to construct needed transmission facilities.

Q. What do you recommend as a remedy for the lack of necessary studies?

A. I recommend that Applicants be ordered to conduct production cost, load flow and stability studies of the effects of combining Applicants' electric systems (and of combining their control areas) upon other utilities. The 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 such a format as to allow 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 four 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 my sixth concern, 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' four 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. A limited study was conducted under my supervision concerning the adequacy of the Missouri transmission system, and that study indicates that problems exist. The study focused on Applicants' transmission system, but monitored the entire Missouri transmission system under summer peak conditions, both normal and with heavy power transfers.

Load flow data for Summer 2000 and 2001 peak base cases were made available by UCU through Data Response EDSPR-28. Despite its clear intention to alter internal dispatch through integration of its four separate load pockets, UCU 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, UCU 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 have 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 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 UCU area (called "MIPU" in the load flow data), and all tie lines between

UCU 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 UCU 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 four pockets of load and generation. 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.

Our analysis of the 2000 summer case, based on normal transfers through Missouri, demonstrated that an outage of the 161 kV line from Sibley to Orrick caused an overloading on the 161 kV line that runs from Sibley toward Duncan. This contingency loaded the line from Sibley to Duncan to 102.6% of its emergency rating, which is considered a criteria violation. The outage of the 161 kV line from Orrick to Richmond affected the same Sibley to Duncan line, and resulted in a loading equal to 101.7% of the line's emergency rating.

In the 2000 summer case with heavy north-to-south transfers through Missouri, a number of criteria violations occurred. Even in the absence of contingencies, overloading existed on the 161 kV line between Sibley and Duncan, which was loaded at 101.7% of its normal rating. Most of the contingencies caused overloading of the 161 kV line from Sibley to Duncan and the 161 kV line from Duncan to Blue Springs East. During an outage of the 161 kV line between Sibley and Orrick, loading on the Sibley to Duncan line increased to 113% of its emergency rating, and loading of the Duncan to Blue Springs East line increased to 102.9% of its emergency rating. Other line outages caused loadings on the Sibley to Duncan and Duncan to Blue Springs East lines to exceed their emergency ratings. Outages on the following 161 kV lines caused overloads: Martin City to Grandview, Greenwood to Lee's Summit, Grandview to Longview, Odessa to Lexington, Lexington to Richmond, and Richmond to Orrick, all owned by UCU. Single outages of these lines caused overloading on the Sibley to Duncan line ranging from 103% to 112% of its emergency rating.

Q. Did any other overloading result from single contingencies simulated on the 2000 summer heavy transfer base case?

A. Yes. Another group of lines collectively experienced overloading during single line contingencies. These were KCPL's 161 kV lines from LR STH to Lake Road, LR STH to Sparta, and Sparta to Nashua. These lines overloaded to 109% of their emergency rating during the single outage of the Stranger Creek to Weston 161 kV line and the Weston to Platte City 161 kV line, both UCU's lines. They also experienced overloadings during a single outage of the 161 kV lines Smithville to Platte City, Smithville to Nashua and Hallmark to Sibley (all UCU's lines), at about 101% of emergency ratings.

Q. Has UCU reported these constraints and proposed future reinforcements?

A. Indirectly yes. UCU reported the need for reinforcement of the transmission system in the Blue Springs, Lee's Summit and Belton areas in the 1999 FERC Form 715 as follows:

> *The Blue Springs, Lee's Summit, and Belton areas are developing very rapidly, and as a result the company is experiencing rapid load growth in these areas. In order to address this rapid load growth, a power plant is to be constructed near*

Pleasant Hill, Missouri. In order to accommodate the new plant and additional load, extensive transmission upgrades are proposed for the system between Pleasant Hill and Blue Springs and also between Pleasant Hill and Lee's Summit. A 345 - 161 KV transformer is also proposed at Pleasant Hill to increase transfer capability into the area. These upgrades are scheduled for completion in time for the 2001 summer peak, and should accommodate the load growth in the area for some time to come.

(The 1999 UCU FERC Form 715, part 6)

Q. Is this information still correct?

A. It appears not. Contingency analysis of the 2001 summer base case showed that proposed transmission reinforcements following the construction of the Aquila's 500 MW generation plant at Pleasant Hill would not eliminate all weaknesses in that area's transmission system. Our study of contingencies revealed several criteria violations. The 161 kV lines from Pleasant Hill to Lake Winnebago and from Lake Winnebago to Hook Road experienced overloading during the outage of the 161 kV line from Greenwood to Lee's Summit. The line from Pleasant Hill to Lake Winnebago was loaded to 107% of its emergency rating, and the line from Lake Winnebago to Hook Road to 101%. The single contingency of the 161 kV line Pleasant Hill to Lake Winnebago caused the overloading of the 161 kV line between Prairie Lee and Lee's Summit to 105.6% of its emergency rating.

Q. Did you find any evidence that UCU is aware of the constraints on KCPL's lines from Lake Road to Sparta and from Sparta to Nashua, or of any actions UCU plans regarding these constraints?

A. UCU is fully aware that outages of lines in its control area cause overloads on KCPL's lines. That was analyzed in the Interconnection Study filed as Mr. Kreul's Schedule RCK-10 on which I commented earlier.

Q. Have you performed an analysis of the St. Joseph L&P transmission system?

A. Yes. I analyzed the load flow data of each Applicant, and performed load flow analyses. However, it appears that St. Joseph L&P reports the same value for both normal and emergency line ratings. This made contingency analysis meaningless.

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 the 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 neither be reported on an OASIS nor 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. Applicants assert that:

> Purchases by the merged company to serve native load will generally decrease due to more efficient use of the merged company's generation resources.

See Schedule__(WAR-3), Response from UtiliCorp's Mr. Gary Clemens to Ms. Sedina Eric's e-mail on March 28, 2000 and the response to Request No. EDSPR-28. However, this response does not address the likelihood that Applicants' purchased power will be diverted to other markets after it is displaced by Applicants' internal generation.

Applicants' testimony stated that:

> As a result of the merger, the new company will be in position to make more efficient use of the lower cost power resources. It can reduce the amount of energy supplied from the higher cost power plants and purchase power contracts. (Robert W. Holzwarth Direct Testimony, page 17, line 2-4)

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 no longer be subject to 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. Other constraints are identified as potential limitations to power transfers in the 1999 SPP FERC Form 715 of Associated Electric Cooperative[5]:

[5] Associated Electric Cooperative is a SERC member.

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. The limits seen to date have not been sufficient to warrant corrective action, however, when they do Associated will make the necessary improvements to its Clinton terminal equipment to mitigate the problem.

Stockton-Morgan 161 kV Line

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 is currently being upgraded and is expected to be operating by the summer of 1999 at a higher rating. This facility will continue to be monitored to determine if additional uprating or other improvements are required.*

(The 1999 SPP FERC Form 715, Associated Electric Cooperative Part 6, Page 9)

The ownership and control of the relevant transmission facilities is not entirely clear but, according to the applicable load flow base case, the Montrose Plant is in KCPL's control area. It is connected to Clinton Substation. This bus is designated as being owned by AEC. However, UtiliCorp (MPS) owns the Clinton 161 kV substation at the same location. MPS reports that a low voltage problem exists at Clinton if the 161 kV source at Clinton substation is interrupted:

Low voltages will result in the Clinton area 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 so low that the load must be shed. (The 1999 SPP FERC Form 715, UtiliCorp MPS Part 5).

Some constrained facilities are associated with parts of a 161 kV line[6] extending from Montrose generation plant to Kansas City Power and Light and Brookline substation – City Utility of Springfield. The line is important to delivering Springfield's entitlement

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

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 the 345 kV lines from LaCygne to Neosho and from Morgan to Brookline. An additional parallel line would release these constraints.

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 which is important to transferring Montrose power to Springfield.

VI. Commitment To Carry Out Needed Upgrades.

Q. What is your next concern?

A. As noted above, I am concerned that insufficient study has been done and that studies required to identify the needed transmission facilities will be completed too late to provide any protection to adversely affected entities. I am further concerned that Applicants have made no specific and binding commitment to construct necessary transmission facilities. Until upgrades identified in these studies are in place, the burden of curtailments will fall on ratepayers of other Missouri utilities.

Applicants have assumed responsibility to pay for transmission upgrades caused by putting all the merged companies under SPP Network Integration Service to the extent that such upgrades are identified as being required in an SPP Impact Study that is now under way. However, this commitment is unduly limited in scope (limited to analyzing only Applicants' pending request for Network Integration Service) and does not specify many elements essential to its enforcement. The commitment would enable Applicants to merge now and establish their obligations later, creates incentives to perform minimally (by making cosmetic fixes or employing operating procedures as opposed to making substantial fixes) and leaves open the possibility of disputes about whether Applicants have performed.

Applicants' limited commitment is provided both in its testimony and in response to Springfield's data request EDSPR-32. Unfortunately, Applicants did not avail themselves of the opportunity to clarify or expand upon their commitment in responding to that data request.

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.

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. UtiliCorp seeks approval of the merger before completion of relevant studies. Thus, not until long after the merger has been approved and consummated will affected parties know the magnitude of any adverse merger impacts, the scope of the SPP study of those impacts, under what criteria the SPP Study will be conducted, how constraints will be defined or how constraints will be alleviated.

b. Once the merger is completed, UtiliCorp will have an incentive to understate the severity of any constraints in any study effort and will have an incentive to carry out 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 abide by the directives of any such ISO or RTO in implementing upgrades.

d. As previously noted, Applicants actually carried out studies of needed transmission unrelated to the SPP study in evaluating the cost-benefit ratio of their mergers. In those studies, Applicants identified certain transmission facility additions as being needed in order to integrate their systems and reflected the costs of those additions in calculating costs and benefits of their mergers. But Applicants have made no commitment to construct those additions and purportedly made no studies of adverse impacts on other transmission users. Instead, Applicants are awaiting SPP's studies in order to determine whether they can integrate their systems and eliminate transmission constraints at a cost lower than that assumed in analyzing its mergers.

Q. Are there many transmission constraints in the region within which Applicants operate that will be adversely affected by the merger and that will potentially limit transmission service needed by Springfield?

A. It appears so, yes. Some constrained facilities are associated with parts of a 161 kV line[7] extending from the Montrose generation plant of Kansas City Power & Light to the Brookline Substation of City Utilities of Springfield. The line is important to delivering Springfield's entitlement in the Montrose generation plant. The Stockton – Morgan

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

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 the 345 kV lines from LaCygne to Neosho and from Morgan to Brookline. An additional parallel line would relieve these constraints.

Applicants conducted a study of the interconnection between UtiliCorp and Empire Schedule__(WAR-5), testimony of Richard C. Kreul, 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 which is important to transferring Montrose power to Springfield.

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 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 four 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:

> *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 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*

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

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.

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 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 order 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.

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 incentives 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. The Commission should therefore impose a condition on its approval of the mergers to require 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]

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.

[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."

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 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).

At present, the Applicants are 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. While no studies have been conducted which indicate whether the existing transmission system is adequate, or for how long it would continue to be adequate, the Applicants are seeking merger approval, subject to the vague assurance that no adverse impact would adversely affect transmission dependent utilities. To those utilities whose access to the supply of reliable economic power is dependent upon the transmission infrastructure in the region, such assurances are not sufficient.

UtiliCorp's history of seeking short-term, self-serving economic benefit from exploiting "seams" between regional transmission systems gives reason to call for more than vague assurances. The failure of Applicants to embrace regional solutions which would insure benefits to all parties within Missouri (while taking a "wait and see" approach to their own economic advantage) only increases the discomfort of third parties. Until uniform regional transmission structures and consistent planning and operating standards can be developed, the Commission should closely monitor mergers that allow Applicants to straddle limited transmission systems and commandeer limited transfer capability.

I propose that 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. In re: Potomac Edison Company, before the Maryland Public Service Commission, Case No. 7055, concerning the need for a 230 Kv transmission line in Montgomery County, Maryland.

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

12. In re: Baltimore Gas and Electric Company, 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. In re: Potomac Electric Power Company, before the Maryland Public Service Commission, Case Nos. 7240A, 7240B, 7240C, 7240D, 7240E, 7240F and 7240G, concerning fuel rate adjustments.

14. In re: Florida Power & Light Company, 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. In re: Oklahoma Gas and Electric Company, FERC Docket No. ER77-465, concerning rates for energy banking and transmission services rendered to the Western Farmers Electric Cooperative.

16. In re: Idaho Power Company, 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. In re: Potomac Electric Power Company, before the District of Columbia Public Service Commission, Case No. 737, concerning the Company's construction program.

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

19. In re: Pacific Gas and Electric Company, 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. <u>In re: Kentucky Utilities Company</u>, FERC Docket Nos. ER-81-341-000 and ER81-267-000, concerning construction planning and the market for short term power.

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

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

32. <u>In re: Central Maine Power Company</u>, 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. <u>In re: Houston Lighting & Power Company</u>, before the Public Utility Commission of Texas, Docket No. 4712, concerning rates to be paid to cogenerators and small power producers.

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

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

36. <u>Dow Chemical Company vs. Houston Lighting & Power Company</u>, 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. <u>In re: The Montana Power Company and the Confederated Salish and Kootenai Tribes of the Flathead Reservation</u>, 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

DATE OF REQUEST: January 20, 2000

DATE RECEIVED: January 20, 2000

DATE DUE: February 8, 2000

REQUESTOR: Jeff Keevil

Supplemental 24

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

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UN
MJ
SF
JF
SE

RECEIVED
FEB 28 2000
WHITFIELD RUSSELL ASSOCIATES

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	54	0	0	0	0	0	0	0	0	0	0	0

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

Forecasted Retail & AQM Peak	478	495	504	513	523	532	541	551	561	571	581	591
WPECO Firm Sale	20	20	20	20	20	20	20	20	20	20	20	20
Municipal Firm Sale	58	59										
KEPCO Firm Sale	40	41	44	47	50	53	57	60	63	66	69	72
KMEA/Osawatomie, KS	1											
DSM	0	0	0	0	0	0	0	0	0	0	0	0
Peak Forecast with DSM	**597**	**615**	**568**	**580**	**593**	**605**	**618**	**631**	**644**	**657**	**670**	**683**
Capacity Reserves (A+B-C)	**101**	**83**	**77**	**108**	**85**	**48**	**(67)**	**(80)**	**(93)**	**(106)**	**(116)**	**(129)**
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	**678**	**699**	**645**	**659**	**674**	**688**	**702**	**717**	**732**	**747**	**761**	**776**
Capacity Balance (A+B-D)	**19**	**(0)**	**(0)**	**29**	**4**	**(35)**	**(151)**	**(166)**	**(181)**	**(196)**	**(207)**	**(222)**

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	2001	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

A. System Generation Capacity			1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Existing Generation Capacity														
EDE	Iatan Share	Coal	80	80	80	80	80	80	80	80	80	80	80	80
EDE	Asbury 1	Coal	193	193	193	193	193	193	193	193	193	193	193	193
EDE	Rvrtn 7	Coal	38	38	38	38	38	38	38	38	38	38	38	38
EDE	Rvrtn 8	Coal	53	53	53	53	53	53	53	53	53	53	53	53
EDE	Ozark Beach	Hydro	16	16	16	16	16	16	16	16	16	16	16	16
Total Base Capacity			380	380	380	380	380	380	380	380	380	380	380	380
EDE	SL CT1	Gas	101	101	101	101	101	101	101	101	101	101	101	101
EDE	SL CT2	Gas	152	152										
EDE	SL CC	Gas			300	300	300	300	300	300	300	300	300	300
EDE	EC 1	Gas	90	90	90	90	90	90	90	90	90	90	90	90
EDE	EC 2	Gas	90	90	90	90	90	90	90	90	90	90	90	90
EDE	Rvrtn 9	Gas	12	12	12	12	12	12	12	12	12	12	12	12
EDE	Rvrtn 10	Gas	16	16	16	16	16	16	16	16	16	16	16	16
EDE	Rvrtn 11	Gas	17	17	17	17	17	17	17	17	17	17	17	17
EDE	Asbury 2	Coal	20	20	20	20	20	20	20	20	20	20	20	
Total Int/Peaking Capacity			498	498	646	646	646	646	646	646	646	646	646	626
Grand Total			878	878	1026	1026	1026	1026	1026	1026	1026	1026	1026	1006
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			**878**	**878**	**1026**	**1026**	**1026**	**1026**	**1026**	**1026**	**1026**	**1026**	**1026**	**1006**

B. Capacity Transactions		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Purchases													
EDE	AEC	100											
EDE	KGE	80	80										
EDE	SPS	45	45										
EDE	WRI	30	162	162	162	162	162	162	162	162	162	162	
EDE	CT Purchase #8												160
EDE	CT Purchase #9												160
EDE	Shrt Trm Purch #7							5	20	40	60	75	
Total Purchases		255	287	162	162	162	162	167	182	202	222	237	320
Sales													
EDE		50	50										
Total Sales		50	50	0	0	0	0	0	0	0	0	0	0
Net Transactions		**205**	**237**	**162**	**162**	**162**	**162**	**167**	**182**	**202**	**222**	**237**	**320**
Total System Capacity (A+B)		**1083**	**1115**	**1188**	**1188**	**1188**	**1188**	**1193**	**1208**	**1228**	**1248**	**1263**	**1326**

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**	**36**	**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

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 20, 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
WHITFIELD 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 printed, 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

Schedule No. 2

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 WAR 01 713

Exhibit WAR - 01 wr MJ J SF 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.

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.

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	

TLR Curtailments

Requester: SPP

Flowgate:FAIRPORT-LATHROP/IATAN STRANGER FLGT.1001

Date: 10/19/99 AT 0115

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
DPC	MPS	2-NH	75	75	0200	DPC_UCUMOO0000669_MPS	
WAUE	MPS	3-ND	90	90	0200	WAUE_UCUMO0000663_MPS	

TLR Curtailments

Requester: SPP

Flowgate: NesOneNesTul #5063

Date: 9/27/99

END TIME:2200

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Origninal Amount	Amount Curtailed	Implementation Time	NERC Tag ID	End Time
MPS	OKGE	NH-2	100	100	1515	MPS_OERI240000001000_OKGE	2200
MPS	OKGE	NH-2	100	100	1515	MPS_OERI240000002000_OKGE	2200
MPS	OKGE	NH-2	100	100	1515	MPS_OERI240000003000_OKGE	2200

TLR Curtailments

Requester: MAPP

Flowgate: COOPER_SOUTH

Date: 8/18/99

END TIME:2219

Curtailments: The following curtailments were made of SPP schedules:

From2219	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
GRE	MPS	NW- 4	50	50	1000	GRE_UCUMO705D000_MPS	2219
WAUE	MPS	NM - 5	45	19	1000	WAUE_UCUMO642D003_MPS	2219
GRE	MPS	NM - 5	48	27	1000	GRE_UCUMO704D002_MPS	2219

TLR Curtailments

Requester: SPP

Flowgate: EAU CLAIRE-ARPIN

Date: 7/16/99

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
SPC	MPS	NH-2	25	25	1800	SPC_TEMUES002T001_MPS	1908

TLR Curtailments

Requester: SPP

Flowgate: **HAWXFRGAWXFR**

Date: **7/08/99**

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	NH-2	50	9	1715	WAUE_RESEE107B000_MPS	2010
WAUE	MPS	NH-2	50	9	1715	WAUE_RESEE118B000_MPS	2010

TLR Curtailments

Requester: SPP

Flowgate: LACYGNE-STILLWELL

Date: 7/8/99

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	NH-2	50	11	1545	WAUE_RESEE107B000_MPS	2130
WAUE	MPS	NH-2	50	11	1545	WAUE_RESEE118B000_MPS	2130
OKGE	SJLP	NH-2	50	32	1545	OKGE_OERI24727X000_SJLP	2130

TLR Curtailments

Requester: SPP

Flowgate: **EAU CLAIRE-ARPIN 345KV**

Date: **6/28/99**

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
GRE	MPS	NH-2	45	45	1000	GRE_UCUMO228C000_MPS	1831
WAUE	MPS	ND-3	50	50	1000	WAUE_UCUMO806B001_MPS	1831
GRE	MPS	NW-4	100	100	1000	GRE_UCUMO101B000_MPS	1831

TLR Curtailments

Requester: MAPP

Flowgate: EAU CLAIRE-ARPIN 345 KV

Date: 6/12/99

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
WAUE	MPS	ND-3	50	25	930	UNKNOWN	

TLR Curtailments

Requester: MAPP

Flowgate: EAU CLAIRE-ARPIN 345 KV

Date: 6/12/99

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
LES	MPS	NH-2	25	25	700	LES_UCUMO064A000_MPS	

TLR Curtailments

Requester: MAIN

Flowgate: EAU CLAIRE to ARPIN

Date:06/10/99

END TIME:

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
SPC	MPS	ND-3	25	15	700	SPC_CRGL1A102A000_MPS	2200
SPC	MPS	ND-3	10	10	1100	SPC_UCUMO102A000_MPS	2200
SPC	MPS	ND-3	8	8	1100	SPC_CRGL1A102A002_MPS	2200
GRE	MPS	NW-4	50	50	1100	GRE_UCUMO504C000_MPS	2200
WAUE	MPS	NW-4	41	41	1100	WAUE_UCUMO502C001_MPS	2200
WAU	MPS	NW-4	9	9	1100	WAUE_UCUMO501C000_MPS	2200

TLR Curtail

Requester: MAIN

Flowgate: EAU CLAIRE-ARPIN 345 KV

Date: 6/7/99
END TIME:
Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
SPC	MPS	NH-2	100	72	700	SPC_CRGL1A069A000_MPS	2100

TLR Curtailments

Requester: EES

Flowgate: NEW MADRID-DELL

Date: 6/3/99

END TIME: The schedules with end times were inadvertently cut due to bad information from the IIDC.

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID	END TIME
AMRN	MPS	NS-1	50	50	900	AMRN_UCUM0397C000_MPS	1100
MPS	OKGE	NH-2	200	179	900	MPS_OERI24628X000_OKGE	
MPS	OKGE	NH-2	21	21	1100	MPS_OERI24628X001_OKGE	

END TIME:Curtailments: The following curtailments were made of SPP schedules: TLR Curtailments
Requester: ALTE

Flowgate: EAU CLAIRE to ARPIN ID 3006

Date: 6/2/99

END TIME: At 0925 MAIN went to level 2b, all schedules that were curtailed may return to pre contingent levels unless covered by MAPP LLR.

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
WAUE	MPS	NH-2	100	9	800	WAUE_UCUMO369C000_MPS
GRE	MPS	NH-2	30	4	800	GRE_UCUMO385C000_MPS
GRE	MPS	NH-2	20	2	800	GRE_UCUMO386C000_MPS

TLR Curtailments

Requester: ALTE

Flowgate: Eau Claire -Arpin 345 kv

Date: 5/17/99

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
WAUE	MPS	NH_2	5	3	1000	WAUE_UCUMO013C001_MPS

TLR Curtailments

Requester: KCPL

Flowgate: StjLaklatStr ID.

Date: 5/15/99

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
SJLP	MPS	NH-2	50	32	1700	SJLP_UCUMO029C000_MPS
MEC	MPS	NH-2	50	33	1700	MEC_UCUMO030C000_MPS

TLR Curtailments

Requester: EES

Flowgate: New Madrid-Dell

Date: 10/1/98

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
MPS	CSWS	NH_2	50	27	1145	MPS_MPSPM339C001_CSWS

TLR Curtailments

Requester: CSWS

Flowgate: CraAshValLyd (Craig Jct-Ashdown 138 kV for the outage of Valliant-Lydia 345 kV)

Date: 9/22/98

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
MPS	CLEC	NH-2	100	15	1715	MPS_OERI941A000_CLEC
MPS	CLEC	NH-2	50	8	1715	MPS_OERI938A000_CLEC

TLR Curtailments

Requester: EES

Flowgate: WilLivWebRic (Wilburt-Livonia 138 kV for the outage of Webre-Richard 500 kV)

Date: 9/2/98

Curtailments: The following curtailments were made of SPP schedules:

From	To	Priority	Original Amount	Amount Curtailed	Implementation Time	NERC Tag ID
MPS	CSWS	NW-4	50	50	1400	MPS_SPM131H001_CSWS

I. INTRODUCTION

The purpose of this study was to determine the preferred option for connecting (either physically or contractually) the UtiliCorp United (UCU) electrical transmission system with the Empire District (EDE) electrical transmission system. Four options for achieving this objective are discussed in this report.

Two categories of options were considered. The first category of options were options that were actual physical interconnections between the two systems. The second category of options were options that involved a contractual interconnection or a combination of physical/contractual interconnections.

Each option is discussed separately in the body of this report with regards to contingency analysis, estimated costs, and MW losses.

II. CONTINGENCY ANALYSIS

Loadflow models were created to simulate the existing transmission system. Initial loadflows were based on the year 2003 Southwest Power Pool summer peak models. Contingency analysis was performed for the existing system and each option to examine the transmission system's ability to perform adequately during a single-contingency situation.

The following contingencies were analyzed:

All facilities in the MPS system
All facilities in the EDE system
All facilities in the KCPL system
All facilities 115kV and above in the WR system
Relevant facilities in the AEC system
All facilities 115kV and above in the MEC system
All other facilities that are normally included in EDE contingency analysis studies

In total, 1406 contingencies were analyzed.

Percentage overloads as discussed in this report refer to the line's emergency rating.

III. EXISTING SYSTEM

A. System Configuration

The existing EDE transmission system (shown on the following page) has two 161kV lines and two 69kV lines that extend north towards the UCU system and provide possible interconnection points.

One possible interconnection location into the EDE system is at the Asbury Generation Station near Asbury, Missouri. There are three 161kV lines exiting this generating station. One line travels southwest to Carthage. Another line travels southwest to Joplin. The other 161kV line travels north to interconnect with the Western Resources system.

A second possible interconnection is location at the end of a 161kV line near Burns, Missouri. This substation is a 161/69kV substation fed from a radial 161kV line (795 ACSR) coming from Aurora. However, there are four 69kV lines exiting this substation that interconnect within the EDE system.

The last two possible interconnection points are normally open 69kV connections with MPS near Lamar (4/0 ACSR) and Warsaw (1/0 Cu). These interconnections are normally open because the Empire 69kV and the MPS are electrically out-of-phase by 30 degrees.

B. Loadflow and Contingency Analysis

The base case loadflow for the existing system (normal transfer scenario) is shown on page **Error! Bookmark not defined.**. The base case was based on a year 2003 Southwest Power Pool case with changes made to account for the addition of the Pleasant Hill plant and recommended transmission system changes due to the St. Joseph Light & Power merger. Nevada generation was off in the base case. Asbury generation was on in the base case and contributing 186 MW of generation.

The two most noticeable areas of concern regarding portions of the system that are impacted by this study are the Nevada area in the UCU system and the Burns area in the EDE system. Voltages in the Nevada area dropped as low as 87.7% (at Adrian) for outages on the 161kV line between Archie and Nevada. Voltages in the Burns area dropped as low as 87.7% an outage of the 161kV line to Burns.

C. Losses

Summer peak losses for the base case totaled 64.8 MW for the UCU and EDE systems.

IV. OPTION 1 - Nevada to Asbury 161kV Line

A. System Configuration

The first option considered for connecting the UCU and EDE electrical systems involved the construction of a 161kV line from near UCU's Nevada Substation to EDE's Asbury Generating Station (see diagram on the following page). This line was estimated to be 35 miles long and was modeled using 1192 ACSR conductor (312 MVA capability).

B. Estimated Cost

The estimated cost for this option is $14.84 million. The costs for this option are broken down as follows:

Construct a new 161kV Substation south of the existing Nevada Substation - $2.5 million
Add a 161kV breaker position at the existing Asbury Substation - $1.5 million
Construct a 161kV line (1192 ACSR) from the new Nevada Substation to Asbury - $10.84 million

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $2.28 million annually and $7,300 / MW-year (for 312 MW of capacity).

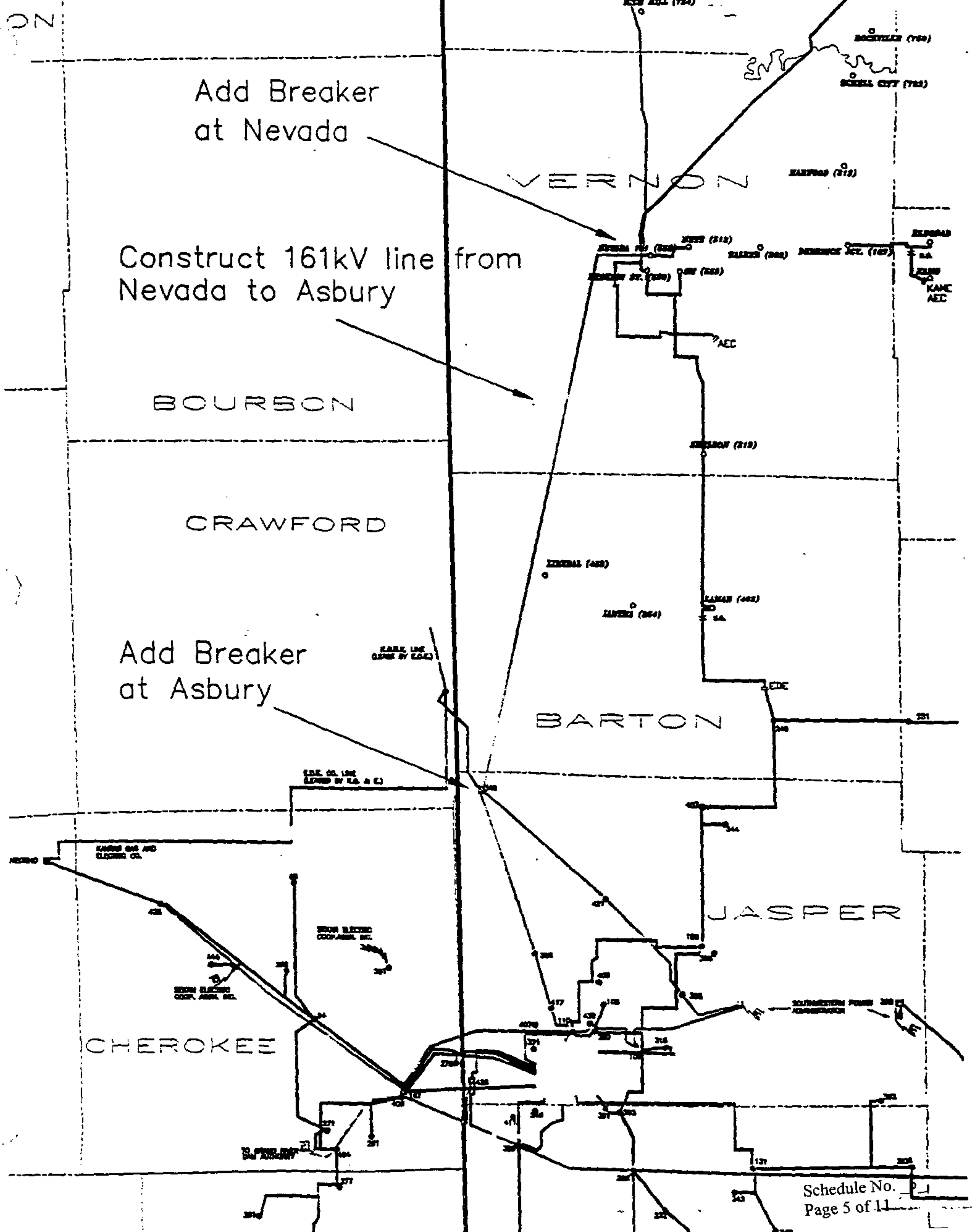
C. Loadflow and Contingency Analysis

The 2003 summer peak model showed 35.6 MW flowing from the Asbury Station to the Nevada Substation (see page **Error! Bookmark not defined.**). Flow from Archie Junction to the Nevada Substation was reduced by 14 MW. Voltages at the Nevada Substation improved from 97.3% to 99.2%.

The primary result of the addition of this line was the elimination of first contingency voltage problems in the Nevada area. In the base case, an outage of any section of the 49 mile line from Archie to Nevada at peak caused low voltages (as low as 87.7%) in the Nevada area. The addition of the line from Nevada to Asbury completely eliminated these single contingency voltage problems.

D. Losses

Losses for this option totaled 63.5 MW for the UCU and EDE systems. This is a peak reduction of 1.3 MW from the base case losses.


Add Breaker
at Nevada
Construct 161kV line from
Nevada to Asbury
Add Breaker
at Asbury
VERNON
BOURBON
CRAWFORD
BARTON
JASPER
CHEROKEE
AEC
EDE
KAMO
AEC

V. OPTION 2 - Sedalia to Burns 161kV Line

A. System Configuration

The second option considered for connecting the UCU and EDE electrical systems involved the construction of a 161kV line from UCU's Sedalia West Substation to EDE's Bolivar-Burns Substation (see diagram on the following page). This line was estimated to be 90 miles long and was modeled using 1192 ACSR conductor (312 MVA capability).

B. Estimated Cost

The estimated cost for this option is $30.87 million. The costs for this option are broken down as follows:

Upgrade to 161kV Substation at Bolivar-Burns Substation - $1.5 million
Add a 161kV breaker position at Sedealia West Substatoin - $1.5 million
Construct a 161kV line from Sedalia West to Bolivar-Burns Substation - $27.87 million

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $4.75 million annually and $15,200 / MW-year (for 312 MW of capacity).

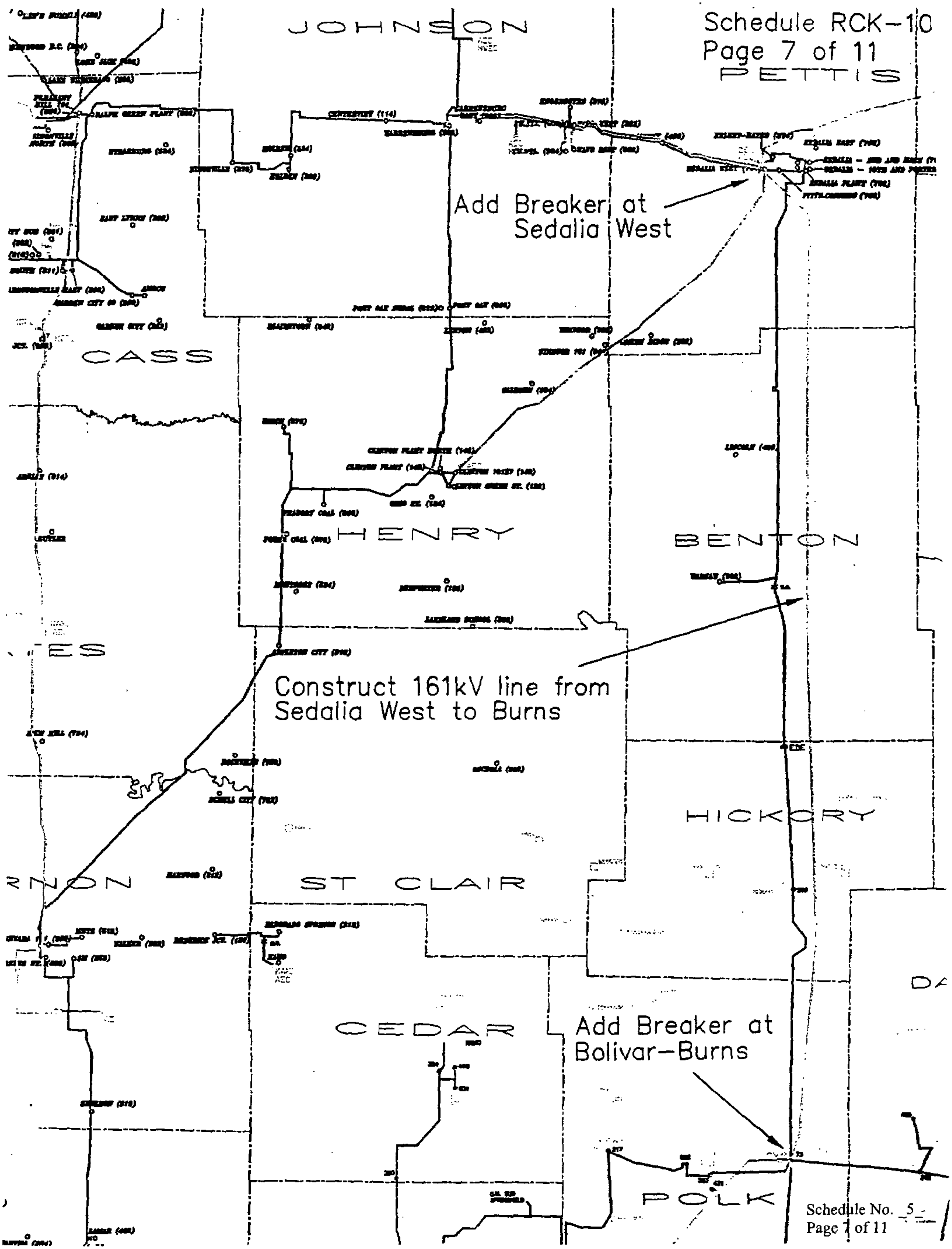
C. Loadflow and Contingency Analysis

The 2003 summer peak model showed 31.6 MW flowing from Sedalia West Substation to the Bolivar-Burns Substation (see page **Error! Bookmark not defined.**). The voltage in the Burns area improved from 97.7% to 99.1%.

The primary result of the addition of this line was the elimination of first contingency voltage problems in the Bolivar-Burns area. In the base case, an outage of any section of the 30 mile line Dadeville East Substation to the Bolivar-Burns Substation caused low voltages (as low as 87.7% at Bolivar South Substation). The addition of the line from Sedalia West to the Bolivar-Burns Substation completely eliminated these single contingency voltage problems.

D. Losses

Losses for this option totaled 65 MW for the UCU and EDE systems. This is an increase of 0.2 MW over the base case losses.


JOHNSON
PETTIS
CASS
HENRY
BENTON
HICKORY
ST CLAIR
CEDAR
POLK
Add Breaker at Sedalia West
Construct 161kV line from Sedalia West to Burns
Add Breaker at Bolivar-Burns

VI. OPTION 3 - Two 69kV Interconnections

A. System Configuration

The third option considered for connecting the UCU and EDE electrical systems involved the addition of two 69kV substations at existing 69kV interconnection points between the UCU and EDE transmission systems. Currently these 69kV interconnections are open because the UCU and EDE systems are 30 degrees out of phase. The new 69kV substations would include 69/69kV phase shifting transformers to bring the two systems into phase. One substation would be built at the 69kV interconnection near Warsaw and EDE's Hermitage Substation and one substation would be built at the 69kV interconnection near Lamar and EDE's Boston Substation (see diagram on the following page). The addition of both of these substations would add approximately 63 MW of interconnection capability at 69kV.

B. Estimated Cost

The estimated cost for this option is $3.5 million ($1.75 million for each substation).

Utilizing a levelized annual carrying charge of 15.4%, the cost of this option is $0.54 million annually and $8,600 / MW-year (for 63 MW of capacity).

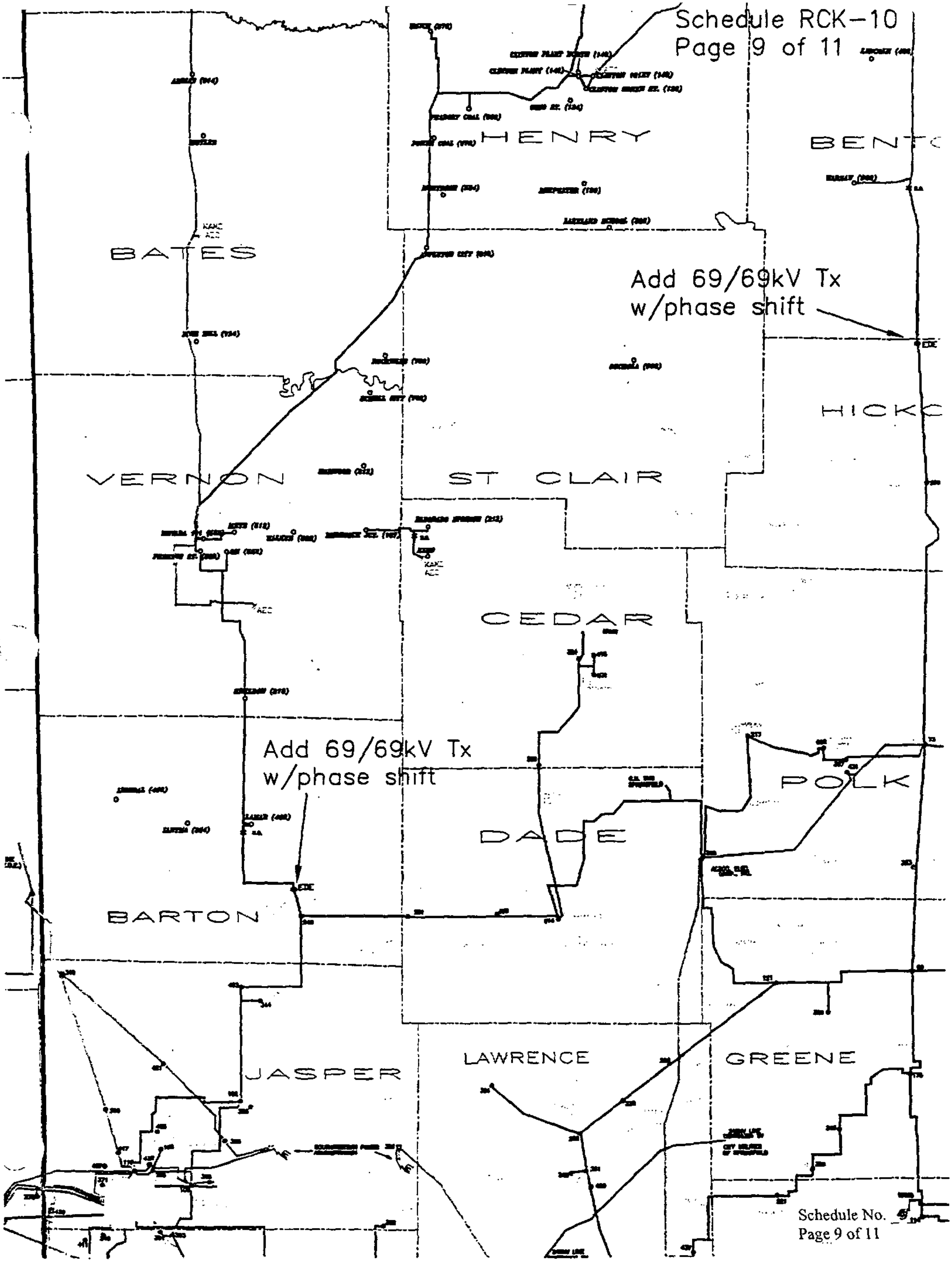
C. Loadflow and Contingency Analysis

The flow on the transformer near Lamar was 3.9 MW from Boston Substation (see page **Error! Bookmark not defined.**). The flow on the transfomer near Warsaw was 0.3 MW from Hermitage Substation. Voltage at Warsaw improved from 94.7% to 97%. Voltage at Lamar increased from 97.9% to 99.2%. Voltages in the EDE system decreased slightly.

This option provided backup to the Lamar area for outages on the 69kV line from Nevada to Lamar. It also provided off-peak backup to the Warsaw and Hermitage areas for outages of the 69kV radial lines serving those areas. Currently these areas have no second feed and are served radially.

D. Losses

Losses for this option totaled 64.7 MW, a decrease of 0.1 MW from the base case.


HENRY
BATES
Add 69/69kV Tx
w/phase shift
EDE
VERNON
ST CLAIR
CEDAR
POLK
Add 69/69kV Tx
w/phase shift
EDE
DADE
BARTON
JASPER
LAWRENCE
GREENE

VII. OPTION 4 - Purchasing Firm Transmission

A. System Configuration

This option involves no changes to the existing transmission system. Necessary transmission capacity would be purchased (from either KCPL or Western Resources).

B. Estimated Cost

It is estimated that 300 MW of transmission capacity is necessary to operate the two systems as one control area and to be able to perform economic dispatch between both systems.

KCPL's current annual revenue requirement for network service is $42,101,320 (includes the Scheduling & Dispatching charge) plus payment for energy losses. If the KCPL system load is estimated at 3,402 MW (2003 summer load), then the load ratio share of 300 MW of transmission capacity is

300 / 3,402 X $42,101,320 = $3.7 million annually (plus energy losses).

The calculation for Western Resources is

300 / 5,400 (estimated 2003 summer peak) X $66,491.775 (annual revenue requirement)
= $3.7 million annually.

The cost for this option is roughly $3.7 million annually or $12,300 / MW-year (300 MW capacity).

C. Loadflow and Contingency Analysis

Because this option does not require any changes to the existing system, the transmission system is unaffected compared to the base case.

D. Losses

Because this option does not require any changes to the existing system, losses for this option are equivalent to the base case.

VIII. SUMMARY

A. Comparing the Options

Determining the preferred method of connecting the UCU and EDE transmission systems from the four options considered in this report is a simple matter given the estimated costs and benefits of each option. Of the four options, Option 1 (Nevada - Asbury) has the lowest costs (see summary of costs on page 13) and provides a benefit to the transmission system. Option 2 (Sedalia - Burns) also provides roughly equivalent benefits to the transmission system, but has substantially higher costs. Option 3 does provide some benefits to the transmission system, but does not provide the necessary 300 MW of interconnection capability that is considered necessary between the two systems. It also has a higher cost on a $ per MW-Year basis than Option 1. Option 4 (buying transmission capacity) provides no benefits to the transmission system and has substantially higher costs than Option 1.

B. Recommendation

The recommended course of action is to construct a 161kV line from a location south of the existing UCU Nevada Substation to the EDE Asbury generating station (see diagram on page 5).

C. Additional Considerations of the Preferred Option

There are least two modifications that can be made to the preferred option that need to be considered.

1. Increasing the Capacity of the Conductor - Replacing the proposed 1192 ACSR conductor with 795 bundled ACSR conductor will increase the capacity of the line from 312 MVA to 510 MVA. If at some point in the future a greater amount of capacity between the two systems is required, it will be more expensive on a $/MW-Year basis to increase the capacity beyond the 312 MVA given by the 1192 ACSR. Additional capacity could be added in the future by completing the 69kV interconnections as described in Option 3 (63 MW) or by purchasing firm capacity as described in Option 4. The difference in costs between these two conductor types is still being evaluated.

   Flow on the Nevada - Asbury line increases by approximately 14% at peak when 795 bundled ACSR conductor is used (as opposed to the 1192 ACSR conductor).

2. Terminating the Connection at Nevada Substation Instead of Further South - Another possibility for this line would have the line terminating at Nevada Substation (see diagram on page 12), instead of further south (as shown on page 5). Originally, the Nevada - Asbury line was considered from the southern location, because it is approximately 7 miles closer to Asbury. Terminating this line at the existing Nevada Substation would add 7 miles of 161kV construction to the cost. However, costs would also be reduced by not requiring the construction of a new 161kV substation. An additional breaker position would be needed at the existing Nevada Substation, if it is decided to terminate the line there. The difference in costs between these two options is still being evaluated.

   If the line is terminated at the existing Nevada Substation, the reliability to Nevada increases slightly. The existing substation would then have three 161kV lines exiting the station and would eliminate the possibility of a radial feed to the substation due to a single 161kV line outage.

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

In Reply Refer To:
Docket Nos. EC00-27-000
and EC00-28-000

April 17, 2000

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Dear Gentlemen:

The purpose of this letter is to request additional information and an amended competitive analysis that will allow the Commission to expedite further consideration of your application pursuant to section 203 of the Federal Power Act.

Your application, filed November 11, 1999, included testimony that described Applicants' possible plans to either physically interconnect the post-merger operating companies or to integrate operations by taking network transmission service under a Regional Transmission Organization's tariff. (Direct Testimony of Richard C. Kreul at 11 - 13.) However testimony filed in support of your Appendix A analysis concluded "it would be too speculative to try to analyze future interconnections that might or might not result from the proposed mergers." (Direct Testimony of Mark W. Frankena at 48.) On February 11, 2000, the Applicants informed the Commission for the first time that the Applicants had applied on December 6, 1999 to the Southwest Power Pool (SPP) for network service. (Consolidated Response to Motions to Intervene, Motions for Clarification, Requests for Hearing, and Protests at 7.) On March 10, 2000, the Applicants stated for the first time that integration would definitely occur. "If UtiliCorp cannot come to terms with the SPP to participate for all purposes under the SPP tariff, the merged company will have to proceed with integration by making its own independent investments in new transmission facilities." (March 10, 2000, Request of Applicants for Leave to Clarify the Record at 5-6.)

In light of the above, it now appears certain that Applicants will integrate their systems but are still contemplating different ways in which to accomplish such integration. The integration of the merging systems could materially change the results of the initial competitive analysis filed by the Applicants as part of their application. The Commission cannot evaluate the competitive effects of the proposed merger without incorporating the effects of such integration and the application does not contain the information necessary to do so. Therefore, please amend your competitive analysis to reflect the integration of the Applicants' systems by: (1) using the SPP tariff, (2) making independent investments in new transmission facilities, and (3) any other mechanism under consideration.

In addition, transactions which may be relevant to the proposed merger's competitive effect have been announced or have taken place since your application was filed. For example, according to UtiliCorp's December 8, 1999 "News Release," UtiliCorp's wholly-owned subsidiary Aquila Energy Corporation (Aquila) signed a 12 year contract to supply natural gas to the American Public Energy Agency. On March 14, 2000, it was announced that Aquila had acquired the marketing assets of U.S. Gas Transportation, Inc. On March 14, 2000, it was announced that Aquila had acquired the real estate and obtained the right to proceed with constructing a gas storage facility in west Texas. Please explain in detail these and any other recent transactions that are relevant to the merger's competitive effect and revise your competitive analysis to reflect such transactions. If the transactions are not relevant to the competitive effect of the merger, than please explain why not.

The changes in Applicant's integration plans and transactions announced subsequent to the filing of your merger application constitute significant changes in your merger proposal requiring revisions to your competitive analysis, as described above. Consistent with the Merger Policy Statement, such changes will start the Commission's merger review process over and will require that a new notice be issued. Your response to this order must be filed within twenty one (21) days of the date of this order. In addition, please provide a copy of your response to all parties that have requested intervention in this proceeding. Those parties will have twenty one (21) days from the date your response is received by the Commission to file comments on the submission.

This order is issued pursuant to 18 CFR 375.307 and is interlocutory. This order is not subject to rehearing pursuant to 18 CFR 385.713. Please submit seven copies of your response to this order. Six copies of your response should be sent to:

Federal Energy Regulatory Commission
Office of the Secretary
888 First Street, N.E.
Washington, DC 20426

One copy should be sent to:

Federal Energy Regulatory Commission
ATTN: Michael C. McLaughlin, Director
Division of Corporate Applications
Office of Markets, Tariffs and Rates
888 First Street, NE
Washington, DC 20426

Sincerely,

Michael C. McLaughlin, Director
Division of Corporate
Applications

In the Matter of the Joint Application of	)
UtiliCorp United Inc. and St Joseph Light &	)
Power Company for Authority to Merge St.	)
Joseph Light & Power Company with and	)**Case No. EM-2000-292**
Into UtiliCorp United Inc., and in	)
Connection Therewith, Certain Other	)
Related Transactions	)

AFFIDAVIT
OF
WHITFIELD A. RUSSELL

WHITFIELD A. RUSSELL, on oath, deposes and states that the foregoing **Rebuttal Testimony and Exhibits**, on behalf of Springfield (MO) City Utilities before the Public Service Commission of the State of Missouri were prepared by him or at his direction and under his supervision, and that if asked the question herein, he would give the answers as shown, and that the facts stated herein are true to the best of his knowledge, information and belief.

WHITFIELD A. RUSSELL

Subscribed and sworn to before me on this 1st day of May, 2000.

James M. Reed
NOTARY PUBLIC
My Commission Expires:

JAMES M. REED
Notary Public District of Columbia
My Commission Expires June 30, 2002