SPP Southwest Power Pool

Final Aggregate Facility Study SPP-2005-AG2-AFS-2 For Transmission Service Requested by Aggregate Transmission Customers

SPP Engineering, SPP Tariff Studies

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1. Executive Summary

Pursuant to Attachment Z of the Southwest Power Pool Open Access Transmission Tariff (OATT), 751 MW of long-term transmission service requests have been restudied in this final Aggregate Facility Study (AFS). This phase of the AFS consists of revisions to reflect the withdrawal of requests for which Letter Agreements were not executed. The principal objective of the AFS is to identify system problems and potential modifications necessary to facilitate these transfers while maintaining or improving system reliability as well as summarizing the operating limits and determination of the financial characteristics associated with facility upgrades. Facility upgrade costs are allocated on a prorated basis to all requests positively impacting any individual overloaded facility. Further, Attachment Z provides for facility upgrade cost recovery by stating that "[a]ny charges paid by a customer in excess of the transmission access charges in compensation for the revenue requirements for allocated facility upgrade(s) shall be recovered by such customer from future transmission service revenues until the customer has been fully compensated."

The total assigned facility upgrade Engineering and Construction (E &C) cost determined by the AFS restudy is $29,767,001. Additionally $18,000,000 of assigned E & C cost for 3rd party facility upgrades are assignable to the customer. The total upgrade levelized revenue requirement for all transmission requests is $86,540,501. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. The AFS data tables reflect the full allocation of upgrade costs to customers based on either the requested reservation period or the deferred reservation period if applicable. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $29,256,186. For those customers who pursue redispatch in lieu of deferral of start of service, levelized revenue requirements will be based upon the deferred start date with redispatch.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service. These include both first-tier neighboring facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. In this AFS, one third-party facility was identified. Total engineering and construction cost estimates for required third-party facility upgrades is $18,000,000. Agreements for third-party impact mitigation must be negotiated by the Transmission Customer and third-party owner with a copy of the agreement provided to SPP prior to start of transmission service.

After completion and posting of the final AFS, the Customer will have 15 days to either confirm or withdraw their transmission request in OASIS. At the completion of this 15 day window, the Transmission Provider will tender Letter Agreements to revise the existing service agreements for new designated network resource requests for those Transmission Customers currently taking SPP Network Integrated Transmission Service (NITS). The Transmission Provider will tender NITS Service and Operating Agreements for new designated network resource requests for those Transmission Customers that are not currently taking SPP NITS. The Transmission Provider will tender service agreements for Point to Point confirmed service. Service Agreements will be tendered based on full allocation of revenue requirements for facility upgrades assignable to the customer contingent upon verification of designated resources meeting Attachment J, Section III B criteria for base plan funding.

After receipt of a Service Agreement from the Transmission Provider, the Customer shall have 15 days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or the request will be deemed terminated and withdrawn. Agreements for generation redispatch in lieu of deferral of start of service must be negotiated by the Transmission Customer and generation owner with a copy of the agreement provided to SPP prior to start of transmission service.

2. Introduction

On January 21, 2005, the Federal Energy Regulatory Commission accepted Southwest Power Pool's proposed aggregate transmission study procedures in Docket ER05-109 to become effective February 1, 2005. The proposed cost allocation and cost recovery provisions were accepted for filing and suspended to become effective the earlier of five months from the requested effective date (July 1, 2005) or a further order of the Commission in the proceeding subject to refund. Since that time, the cost allocation and cost recovery provisions have been accepted with modification. The following link can be used to access the SPP Regulatory/FERC webpage: (http://www.spp.org/Objects/FERC_filings.cfm). The hyperlinks under the heading ER05-109 (Attach Z Filing) open Southwest Power Pool's October 29, 2004 filing containing Attachment Z to the SPP OATT and the Commission's January 21, 2005 Order. In compliance with this Order, the second open season commenced on June 1, 2005. All requests for long-term transmission service received prior to October 1, 2005 with a signed study agreement were then included in the second Aggregate Transmission Service Study (ATSS).

751MW of long-term transmission service has been restudied in this final Aggregate Facility Study (AFS) with over $29 Million in transmission upgrades being proposed. The results of the final AFS are detailed in Tables 1 through 6. A highly tangible benefit of studying transmission requests aggregately under the SPP OATT Attachment Z is the sharing of costs among customers using the same facility. The detailed results show individual upgrade costs by study as well as potential base plan allowances as determined by Attachments J and Z. The following link can be used to access the SPP OATT:

(http://www.spp.org/Publications/SPP_Tariff.pdf). In order to understand the extent to which base plan upgrades may be applied to both point-to-point and network transmission services, it is necessary to highlight the definition of Designated Resource. Per Section 1.9a of the SPP OATT, a Designated Resource is "[a]ny designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis." Therefore, not only network service, but also point-to-point service has potential for base plan funding if the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J are met.

Pursuant to Attachment J, Section III B of the SPP OATT, the Transmission Customer must provide SPP information necessary to verify that the new or changed Designated Resource meets the following conditions:

1. Transmission Customer's commitment to the requested new or changed Designated Resource must have a duration of at least five years.
2. During the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer's existing Designated Resources plus the lesser of (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer's projected system peak responsibility determined pursuant to SPP Criteria 2.

According to Attachment Z Section VI.A, Point-to-Point customers pay the higher of the monthly transmission access charge (base rate) or the monthly revenue requirement associated with the assigned facility upgrades including any prepayments for redispatch required during construction.

Network Integration Transmission Service customers pay the total monthly transmission access charges and the monthly revenue requirement associated with the facility upgrades including any prepayments for redispatch during construction.

Transmission Customers paying for a directly assigned network upgrade shall receive credits for new transmission service using the facility as specified in Attachment Z Section VII.

Facilities identified as limiting the requested Transmission Service have been reviewed to determine the required in-service date of each Network Upgrade. The year that each Network Upgrade is required to accommodate a request is determined by interpolating between the applicable model years given the respective loading data. Both previously assigned facilities and the facilities assigned to this request for Transmission Service were evaluated.

In some instances due to lead times for engineering and construction, Network Upgrades may not be available when required to accommodate a request for Transmission Service. When this occurs, the ATC with available Network Upgrades will be less than the capacity requested during either a portion of or all of the requested reservation period. As a result, the lowest seasonal allocated ATC within the requested reservation period will be offered to the Transmission Customer on an applicable annual basis as listed in Table 1. The ATC may be limited by transmission owner planned projects and not only by customer assigned upgrades.

Some constraints identified in the AFS were not assigned to the Customer as the Transmission Provider determined that upgrades are not required due to various reasons or the Transmission Owner has construction plans pending for these upgrades. These facilities are listed by reservation in Table 3. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer. Table 6 lists possible redispatch pairs that may allow start of service prior to completion of assigned network upgrades.

A. <u>Financial Analysis</u>

The AFS utilizes the allocated customer E & C cost in a present worth analysis to determine the monthly levelized revenue requirement of each facility upgrade over the term of the reservation. In some cases, network upgrades cannot be completed within the requested reservation period, thus deferred reservation periods will be utilized in the present worth analysis. For those customers who pursue redispatch agreements to avoid deferral of start of service the present worth analysis will be based on the deferred start date with redispatch as shown in Table 1 and 2. The upgrade levelized revenue requirement includes interest, depreciation, and carrying costs.

Each request for Transmission Service is evaluated independently as the cost associated with each Network Upgrade is assigned to a request. When facilities are upgraded throughout the reservation period, the Transmission Customer shall 1) pay the total E & C costs and other annual operating costs associated with the new facilities, and 2) receive credits associated with the depreciated book value of removed usable facilities, salvage value of removed non-usable facilities, and the carrying charges, excluding depreciation, associated with all removed usable facilities based on their respective book values.

<u>B. Third-Party Facilities</u>

For third-party facilities listed in Table 5 and Table 3, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the

Transmission Provider's OATT. In this AFS, one third-party facility was identified. Total engineering and construction cost estimates for required third-party facility upgrades is $18,000,000. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making arrangements for necessary engineering, permitting, and construction of the third-party facilities. Third-party facility upgrade engineering and construction cost estimates are not utilized to determine the present worth value of levelized revenue requirements as is SPP system network upgrades.

All modeled facilities within the Transmission Provider system were monitored during the development of this Study as well as certain facilities in first-tier neighboring systems. Third-party facilities must be upgraded when it is determined that they are overloaded while accommodating the requested Transmission Service. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT.

3. Study Methodology

A. Description

The system impact analysis was conducted to determine the steady-state impact of the requested service on the SPP and first tier Non - SPP control area systems. The steady-state analysis was done to ensure current SPP Criteria and NERC Reliability Standards requirements are fulfilled. The Southwest Power Pool conforms to the NERC Reliability Standards, which provide the strictest requirements, related to voltage violations and thermal overloads during normal conditions and during a contingency. It requires that all facilities be within normal operating ratings for normal system conditions and within emergency ratings after a contingency. Normal operating ratings and emergency operating ratings monitored are Rate A and B in the SPP MDWG models, respectively. The upper bound and lower bound of the normal voltage range monitored is 105% and

95%. The upper bound and lower bound of the emergency voltage range monitored is 110% and 90%. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations.

The contingency set includes all SPP control area branches and ties 69kV and above, first tier Non - SPP control area branches and ties 115 kV and above, any defined contingencies for these control areas, and generation unit outages for the control areas with SPP reserve share program redispatch. The monitor elements include all SPP control area branches, ties, and buses 69 kV and above, and all first tier Non – SPP control area branches and ties 69 kV and above. Voltage monitoring was performed for SPP control area buses 69 kV and above.

A 3 % transfer distribution factor (TDF) cutoff was applied to all SPP control area facilities. For first tier Non – SPP control area facilities, a 3 % TDF cutoff was applied to AECI, AMRN, and ENTR and a 2 % TDF cutoff was applied to MEC, NPPD, and OPPD. For voltage monitoring, a 0.02 per unit change in voltage must occur due to the transfer or modeling upgrades to be considered a valid limit to the transfer.

B. Model Development

SPP used twelve seasonal models to study the aggregate transfers of 751MW over a variety of requested service periods. The SPP MDWG 2005 Series Cases Update 4 2005/06 Winter Peak (05WP), 2006 April Minimum (06AP), 2006 Spring Peak (06G), 2006 Summer Shoulder (06SH), 2006 Summer Peak (06SP), 2006 Fall Peak (06FA), 2006/07 Winter Peak (06WP), 2007 Summer Peak (07SP), 2007/08 Winter Peak (07WP), 2010 Summer Peak (10SP), 2010/11 Winter Peak (10WP), and 2015 Summer Peak (15SP) were used to study the impact of the requested service on the transmission system. The Spring Peak models apply to April and May, the Summer Peak models apply to June through September, the Fall Peak models apply to October and November, and the Winter Peak models apply to December through March.

The chosen base case models were modified to reflect the most current modeling information. Four groups of requests were developed from the aggregate of 751 MW in order to minimize counterflows among requested service. Each request was included in two to four groups depending on the requested path. From the thirteen seasonal models, three system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2005 Series Cases flowing in a West to East direction with ERCOT exporting and SPS exporting to outside zones and exporting to the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2005 Series Cases flowing in an East to West direction with ERCOT net importing and SPS importing from an outside zone and exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2005 Series Cases flowing in a West to East direction with ERCOT net importing and SPS importing from an outside zone and importing from the Lamar HVDC Tie. The system scenarios were developed to minimize counter flows from previously confirmed, higher priority requests not included in the MDWG Base Case.

C. Transfer Analysis

Using the selected cases both with and without the requested transfers modeled, the PSS/E Activity ACCC was run on the cases and compared to determine the facility overloads caused or impacted by the transfer. Transfer distribution factor cutoffs (SPP and 1st-Tier) and voltage threshold (0.02 change below 0.90 pu) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

D. Curtailment and Redispatch Evaluation

During any period when SPP determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, SPP will take whatever actions that are reasonably necessary to maintain the reliability of the Transmission System. To the extent SPP determines that the reliability of the Transmission System can be maintained by redispatching resources, SPP will evaluate curtailment of confirmed service or redispatch of units to provide service prior to completion of any assigned network upgrades. Any redispatch may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Transmission Customer's use of the Transmission System to serve its designated load. Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades.

SPP determined potential relief pairs to relieve the incremental MW impact on limiting facilities as identified in Table 6. Using the selected cases where the limiting facilities were identified, potential incremental and decremental units were identified by determining the generation amount available for increasing and decreasing from the units generation amount, maximum generation amount, and minimum generation amount. If the incremental or decremental amount was greater than 10 MW, the unit was considered as a potential incremental or decremental unit. Generation shift factors were calculated for the potential incremental and decremental units using Managing and Utilizing System Transmission (MUST). From the generation shift factors for the incremental and decremental units, top 100 relief pairs with a greater than 3% TDF were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. The potential relief pairs were evaluated to determine impacts on limiting facilities in the SPP and 1st-Tier systems. The redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

Agreements for generation redispatch must be negotiated by the Transmission Customer and the Generation Owner with a copy of the agreement provided to SPP prior to start of transmission service.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the final AFS. This table lists deferred start and stop dates and the minimum annual allocated ATC without upgrades and season of first impact. The deferred dates of the reservation are given both with and without redispatch that may be available for limitations that are deferring the start of service. Table 2 identifies total E & C cost allocated to each Transmission Customer, third party E & C cost assignments, potential base plan E & C funding (lower of allocated E & C or Attachment J Section III B criteria), total revenue requirements for assigned upgrades in consideration of potential base plan funding, total revenue requirements for assigned upgrades without consideration of potential base plan funding over the term of the reservation (both with and without redispatch), point-to-point base rate charge and final total cost allocation to the Transmission Customer. Table 3 provides additional details for each request including all assigned facility upgrades required, allocated E & C costs, allocated revenue requirements for upgrades, upgrades not assigned to customer but required for service to be confirmed, facilities limiting rollover rights, credits to be paid for previously assigned AFS facility upgrades, any impacted facilities requiring redispatch agreements to provide transmission service, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Earliest Date Upgrade is required (COD), Estimated Date of Upgrade Completion (EOC), and Estimated E & C cost. Table 5 lists identified Third-Party constrained facilities. Table 6 identifies potential redispatch pairs available to relieve the aggregate impacts on identified constraints to prevent deferral of start of service.

Potential base plan funding allowable is contingent upon meeting each of the conditions for classifying upgrades associated with designated resources as base plan upgrades as defined in Section III.B of Attachment J. The lesser of the planned maximum net dependable capacity or the requested capacity is multiplied by $180,000 to determine potential base plan funding allowable. If this additional capacity exceeds the 125% resource to load criteria for a given year, the value of capacity not exceeding 125% of load will set the determinant for base plan funding consideration. For example, a customer submits a request to add a new resource of 50MW in 2010 that meets all other conditions for base plan funding. The Customer's load forecast for 2010 is 500MW with forecasted firm resources of 600MW. The additional 50MW of resources increases the resource to load ratio from 120% to 130%. Therefore the portion of the 50MW request not exceeding 125% resource to load, or 25MW, would be compared to the E & C cost for the full 50MW to determine a prorata share of the cost that can be covered by base plan funding. Any allocated customer costs in excess of base plan funding will be assigned to the customer.

The 125% resource to load determination is performed on a per request basis and is not based on a total of designated resource requests per Customer. A footnote will provide the maximum resource designation allowable for base plan funding consideration per Customer basis per year.

Base plan funding verification requires that each Transmission Customer with potential for base plan funding provide SPP power supply contracts or agreements verifying that the firm capacity of the requested designated resource is committed for a minimum five year duration.

B. Study Definitions

The Commercial Operation Date (COD) is the earliest date the upgrade is required to alleviate a constraint considering all requests. End of Construction (EOC) is the estimated date the upgrade will be completed and in service. The Total Engineering and Construction Cost (E & C) is the upgrade solution cost as determined by the transmission owner. The Transmission Customer Allocation Cost is the estimated engineering and construction cost based upon the allocation of costs to all Transmission Customers in the AFS who positively impact facilities by at least 3% subsequently overloaded by the AFS. Minimum ATC is the portion of the requested capacity that can be accommodated with out upgrading facilities. Annual ATC allocated to the Transmission Customer is determined by the least amount of allocated seasonal ATC within each year of a reservation period.

5. Conclusion

The results of the AFS show that limiting constraints exist in many areas of the regional transmission system. Due to these constraints, transmission service cannot be granted unless noted in Table 3.

After completion and posting of the final AFS, the Customer will have 15 days to either confirm or withdraw their transmission request on OASIS. At the completion of this 15 day window, the Transmission Provider will tender Letter Agreements to revise the existing service agreements for new designated network resource requests for those Transmission Customers currently taking SPP Network Integrated Transmission Service (NITS). The Transmission Provider will tender NITS Service and Operating Agreements for new designated network resource requests for those Transmission Customers that are not currently taking SPP NITS. The Transmission Provider will tender service agreements for Point to Point confirmed service. Service Agreements will be tendered based on full allocation of revenue requirements for facility upgrades assignable to the customer contingent upon verification of designated resources meeting Attachment J, Section III B criteria for base plan funding. After receipt of a Service Agreement from the Transmission Provider, the Customer shall have 15 days to execute a Service Agreement or request the filing of an unexecuted Service Agreement or the request will be deemed terminated and withdrawn.

The Transmission Provider must receive an unconditional and irrevocable letter of credit upon the Transmission Customer's execution of the Service Agreement. This amount is for all assignable Network Upgrades less pre-payment requirements. The amount of the letter of credit will be adjusted down on an annual basis to reflect amortization of these costs. The Transmission Provider will issue letters of authorization to construct facility upgrades to the constructing Transmission Owner. This date is determined by the engineering and construction lead time provided for each facility upgrade.

Appendix A

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)

1. Tap adjustment – Stepping
2. Area interchange control – Tie lines only
3. Var limits – Apply immediately
4. Solution options - X Phase shift adjustment
   _ Flat start
   _ Lock DC taps
   _ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)

1. MW mismatch tolerance – 0.5
2. Contingency case rating – Rate B
3. Percent of rating – 100
4. Output code – Summary
5. Min flow change in overload report – 1mw
6. Excld cases w/ no overloads form report – YES
7. Exclude interfaces from report – NO
8. Perform voltage limit check – YES
9. Elements in available capacity table – 60000
10. Cutoff threshold for available capacity table – 99999.0
11. Min. contng. case Vltg chng for report – 0.02
12. Sorted output – None

Newton Solution:

1. Tap adjustment – Stepping
2. Area interchange control – Tie lines only
3. Var limits - Apply automatically
4. Solution options - X Phase shift adjustment
   _ Flat start
   _ Lock DC taps
   _ Lock switched shunts

Table 1 - Long-Term Transmission Service Requests Included in Aggregate Facility Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date without Redispatch	Deferred Stop Date without Redispatch	Start Date with Redispatch	Stop Date with Redispatch	Mimimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period
CALP	SPP-2005-005D	826675	NPPD	ERCOTE	50	1/1/2006	1/1/2008	6/1/2008	6/1/2010	N/A	N/A	0	06SP
EDE	AG2-2005-064	973355	KCPL	EDE	100	1/1/2010	1/1/2030			N/A	N/A	0	10SP
EDE	AG2-2005-021	973373	EES	EDE	50	1/1/2010	1/1/2030			N/A	N/A	0	10SP
KMEA	SPP-2003-275	610383	GRDA	WR	5	5/1/2009	5/1/2010			N/A	N/A	0	10SP
KMEA	AG2-2005-034	974592	GRDA	KCPL	9	5/1/2006	5/1/2026	10/1/2007	10/1/2026	10/1/2006	10/1/2026	0	06SP
KMEA	AG2-2005-035	974596	GRDA	KCPL	6	5/1/2006	5/1/2026	10/1/2007	10/1/2026	10/1/2006	10/1/2026	0	06SP
KMEA	AG2-2005-039	974637	GRDA	WR	1	5/1/2009	5/1/2026			N/A	N/A	0	15SP
KMEA	AG2-2005-040	974645	GRDA	WR	2	5/1/2009	5/1/2026			N/A	N/A	N/A	N/A
KMEA	AG2-2005-041	974650	GRDA	WR	3	5/1/2009	5/1/2026			N/A	N/A	0	10SP
KMEA	AG2-2005-042	974656	GRDA	WR	3	5/1/2009	5/1/2026			N/A	N/A	0	10SP
KMEA	AG2-2005-043	974658	GRDA	WR	3	5/1/2006	5/1/2026	10/1/2006	10/1/2026	N/A	N/A	0	06SP
KMEA	AG2-2005-044	974660	GRDA	WR	3	5/1/2006	5/1/2026	10/1/2007	10/1/2026	10/1/2006	10/1/2026	0	06SP
KMEA	AG2-2005-063	974926	GRDA	WPEK	1	5/1/2010	5/1/2026			N/A	N/A	0	10SP
KMEA	AG2-2005-058	974976	GRDA	WPEK	3	5/1/2006	5/1/2026	10/1/2007	10/1/2026	N/A	N/A	0	06SP
KMEA	AG2-2005-059	974977	GRDA	WPEK	2	5/1/2010	5/1/2026			N/A	N/A	0	10SP
SPSM	AG2-2005-053	974790	CSWS	SPS	50	1/1/2007	1/1/2012			N/A	N/A	0	07SP
SPSM	AG2-2005-053	974791	CSWS	SPS	50	1/1/2007	1/1/2012			N/A	N/A	0	07SP
SPSM	AG2-2005-053	974793	CSWS	SPS	50	1/1/2007	1/1/2012			N/A	N/A	0	07SP
SPSM	AG2-2005-053	974797	CSWS	SPS	50	1/1/2007	1/1/2012			N/A	N/A	0	07SP
UCU	AG2-2005-078	977014	WPEK	MPS	20	7/1/2006	7/1/2017	10/1/2007	10/1/2018	7/1/2006	7/1/2017	0	06SH
UCU	AG2-2005-079D	977018	WPEK	MPS	40	7/1/2006	7/1/2017	10/1/2006	10/1/2017	7/1/2006	7/1/2017	0	10SP
WFEC	AG2-2005-062	971951	WFEC	WFEC	250	5/1/2010	5/1/2035			N/A	N/A	0	10SP

Table 2 - Total Revenue Requirements Associated with Long-Term Transmission Service Requests

Customer	Study Number	Reservation	Engineering and Construction Cost of Upgrades Allocated to Customer for Revenue Requirements	[2]Additional Engineering and Construction Cost of Upgrades Assigned to Customer (3rd party)	[5]Potential Base Plan Engineering and Construction Funding Allowable	Total Revenue Requirements for Assigned Upgrades over term of reservation without potential base plan funding allocation without redispatch	Total Revenue Requirements for Assigned Upgrades over term of reservation without potential base plan funding allocation with redispatch	[6]Total Revenue Requirements for Assigned Upgrades over term of reservation WITH potential base plan funding allocation	Point-to-Point Base Rate over reservation period	[3]Total Cost of Reservation Assignable to Customer
CALP	SPP-2005-005D	826675	$ -	$ 18,000,000	$ -	$ -	$ -	$ -	$ 1,260,000	$ 19,260,000
EDE	AG2-2005-064	973355	$ 5,385,310		$ 3,985,130	[1] $ 16,633,295	$ 16,633,295	$ 4,324,655	$ -	$ 16,633,295
EDE	AG2-2005-021	973373	$ 2,750,498		$ -	[1] $ 8,483,025	$ 8,483,025	$ 8,483,025	$ -	$ 8,483,025
KMEA [7]	SPP-2003-275	610383	$ 23,963		$ -	$ 38,761	$ 38,761	$ 38,761	$ 78,000	$ 78,000
KMEA [8]	AG2-2005-034	974592	$ 31,659		$ 31,659	$ 87,759	$ 82,976	$ -	$ -	$ 87,759
KMEA [8]	AG2-2005-035	974596	$ 20,360		$ 20,360	$ 56,437	$ 53,361	$ -	$ -	$ 56,437
KMEA [8]	AG2-2005-039	974637	$ 25,576		$ -	$ 69,764	$ 69,764	$ 69,764	$ -	$ 69,764
KMEA [8]	AG2-2005-040	974645	$ -		$ -	$ -	$ -	$ -	$ -	
KMEA [8]	AG2-2005-041	974650	$ 12,699		$ -	$ 37,894	$ 37,894	$ 37,894	$ 795,600	$ 795,600
KMEA [8]	AG2-2005-042	974656	$ 12,488		$ -	$ 37,263	$ 37,263	$ 37,263	$ 795,600	$ 795,600
KMEA [8]	AG2-2005-043	974658	$ 1,128,617		$ 540,000	$ 2,663,292	$ 2,663,292	$ 1,389,009	$ 936,000	$ 2,663,292
KMEA [8]	AG2-2005-044	974660	$ 12,034		$ 12,034	$ 33,358	$ 31,540	$ -	$ 936,000	$ 936,000
KMEA [8]	AG2-2005-063	974926	$ 79,233		$ 79,233	$ 243,441	$ 243,441	$ -	$ 187,776	$ 243,441
KMEA [8]	AG2-2005-058	974976	$ 13,433		$ 13,433	$ 37,236	$ 37,236	$ -	$ 704,160	$ 704,160
KMEA [8]	AG2-2005-059	974977	$ 8,955		$ 8,955	$ 28,216	$ 28,216	$ -	$ 375,552	$ 375,552
SPSM	AG2-2005-053	974790	$ 415,956		$ 415,956	$ 645,997	$ 645,997	$ -	$ 4,800,000	$ 4,800,000
SPSM	AG2-2005-053	974791	$ 415,956		$ 415,956	$ 645,997	$ 645,997	$ -	$ 4,800,000	$ 4,800,000
SPSM	AG2-2005-053	974793	$ 415,956		$ 415,956	$ 645,997	$ 645,997	$ -	$ 4,800,000	$ 4,800,000
SPSM	AG2-2005-053	974797	$ 415,956		$ 415,956	$ 645,997	$ 645,997	$ -	$ 4,800,000	$ 4,800,000
UCU	AG2-2005-078	977014	$ -		$ -	$ -	$ -	$ -	$ 4,253,040	$ 4,253,040
UCU	AG2-2005-079D	977018	$ -		$ -	$ -	$ -	$ -	$ 8,506,080	$ 8,506,080
WFEC	AG2-2005-062	971951	$ 18,598,348		$ 13,613,991	[4] $ 55,506,772	$ 55,506,772	$ 14,875,814	$ -	$ 55,506,772
			$ 29,767,001	**$ 18,000,000**	**$ 19,968,619**	**$ 86,540,501**	**$ 86,530,824**	**$ 29,256,186**		**$ 138,647,817**

Note 1. 2010 EMDE capacity is based on JEC renewed as a resource. Therefore, a maximum of 74MW of the 150MW of capacity requested can be considered for potential base plan funding. This was allocated against the 100 MW request.

Note 2. Additional Engineering and Construction costs assignable to customer based on 3rd party upgrades. These include 1st tier facilities outside SPP and Transmission Owner facilities within SPP that are not under the SPP OATT. Customer is responsible for mitigatin this impact prior to start of service.

Note 3. For PTP requests, total cost is based on the higher of the base rate or assigned upgrade revenue requirements. For Network requests, the total cost is based on the assigned upgrade revenue requirement. Allocation of base plan funding will be determined after verification of designated resource meeting Attachment J, Section II B Criteria. Additionally E & C of 3rd Party upgrades is assignable to Customer. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements without redispatch or base plan funding. Customer is responsible for negotiating redispatch costs if applicable.

Note 4. For WFEC 250MW request, 183MW of requested capacity can be considered for base plan funding prior to meeting 125% cap of resource to load under SPP NITS.

Note 5. If potential base plan funding is applicable, this value is the lesser of the Engineering and Construction costs of assignable upgrades or the value of base plan funding calculated pursuant to Attachment J, Section III B criteria. Allocation of base plan funding is contingent upon verification of customer agreements meeting Attachment J, Section II B criteria.

Note 6: Revenue requirements in consideration of base plan funding are identical both with and without redispatch in this study.

Note 7: Redispatch is required to provide service. See Table 6 for redispatch pairs.

Note 8: These requests impact the GRDA 412Sub-Kansas Tap 161kv and 412Sub-Kerr 161kv facilities that were assigned to KPP in SPP-2005-AG1. Service agreements have not been executed for this service at this time.

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
CALP SPP-2005-005D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
CALP	826675	NPPD	ERCOTE	50	1/1/2006	1/1/2008	6/1/2008	6/1/2010	$ -	$ 1,260,000	$ -	$ -
									$ -	$ 1,260,000	$ -	$ -

Third Party Limitations

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost
826675	3BISMRK - 3HSEHVW 115KV CKT 1	6/1/2006	6/1/2008	$ 18,000,000	$ 18,000,000
			Total	**$ 18,000,000**	**$ 18,000,000**

Customer **Study Number**
EDE AG2-2005-021

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
EDE	973373	EES	EDE	50	1/1/2010	1/1/2030			$ -	$ -	$ 2,750,498	$ 8,483,025
									$ -	$ -	$ 2,750,498	$ 8,483,025

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
973373	Nichols St. Sub Bus - Nichols St. Sub 69KV	6/1/2015	6/1/2015	$ 348,262	$ 1,000,000	$ 831,474
	SUB 110 - ORONOGO JCT. - SUB 167 - RIVERTON 161KV CKT 1	6/1/2011	6/1/2011	$ 1,748,604	$ 5,400,000	$ 5,569,616
	SUB 110 - ORONOGO JCT. (ORONOGO) 161/69/12.5KV TRANSFORMER CKT 1	6/1/2011	6/1/2011	$ 653,632	$ 2,000,000	$ 2,081,935
			Total	$ 2,750,498	$ 8,400,000	$ 8,483,025

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
973373	BULL SHOALS - BULL SHOALS 161KV CKT 1 SWPA	6/1/2011	6/1/2011
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	6/1/2015	6/1/2015
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 OKGE	6/1/2015	6/1/2015
	RIVERSIDE CAPACITOR	6/1/2015	6/1/2015
	SUB 389 - JOPLIN SOUTHWEST - SUB EXPLORER SPRING CITY TAP 69KV CKT 1	6/1/2008	6/1/2009
	SUB 389 - JOPLIN SOUTHWEST (JOPLINSW) 161/69/12.5KV TRANSFORMER CKT 1	6/1/2011	6/1/2011

Customer **Study Number**
EDE AG2-2005-064

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
EDE	973355	KCPL	EDE	100	1/1/2010	1/1/2030			$ 3,985,130	$ -	$ 5,385,310	$ 16,633,295
									$ 3,985,130	$ -	$ 5,385,310	$ 16,633,295

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
973355	Nichols St. Sub Bus - Nichols St. Sub 69KV	6/1/2015	6/1/2015	$ 651,738	$ 1,000,000	$ 1,556,022
	SUB 110 - ORONOGO JCT. - SUB 167 - RIVERTON 161KV CKT 1	6/1/2011	6/1/2011	$ 3,387,204	$ 5,400,000	$ 10,788,850
	SUB 110 - ORONOGO JCT. (ORONOGO) 161/69/12.5KV TRANSFORMER CKT 1	6/1/2011	6/1/2011	$ 1,346,368	$ 2,000,000	$ 4,288,423
			Total	$ 5,385,310	$ 8,400,000	$ 16,633,295

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
973355	166TH STREET - JAGGARD JUNCTION 115KV CKT 1	6/1/2013	6/1/2013
	BULL SHOALS - BULL SHOALS 161KV CKT 1 SWPA	6/1/2011	6/1/2011
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	6/1/2015	6/1/2015
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 OKGE	6/1/2015	6/1/2015
	RIVERSIDE CAPACITOR	6/1/2015	6/1/2015
	SUB 389 - JOPLIN SOUTHWEST - SUB EXPLORER SPRING CITY TAP 69KV CKT 1	6/1/2008	6/1/2009
	SUB 389 - JOPLIN SOUTHWEST (JOPLINSW) 161/69/12.5KV TRANSFORMER CKT 1	6/1/2011	6/1/2011

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
973355	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1	6/1/2013	6/1/2013

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
KMEA SPP-2003-275

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	610383	GRDA	WR	5	5/1/2009	5/1/2010			$ -	$ 78,000	$ 23,963	$ 38,761
									$ -	$ 78,000	$ 23,963	$ 38,761

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
610383	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 2,995	$ 200,000	$ 5,065
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 14,977	$ 1,000,000	$ 23,565
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 5,991	$ 400,000	$ 10,131
			Total	$ 23,963	$ 1,600,000	$ 38,761

Facilities requiring redispatch in order to provide service.

Reservation	Upgrade Name	COD
610383	NORTH AMERICAN PHILIPS - NORTH AMERICAN PHILIPS JUNCTION (SOUTH) 115KV CKT 1	12/1/2009
	NORTH AMERICAN PHILIPS JUNCTION (SOUTH) - WEST MCPHERSON 115KV CKT 1	12/1/2009

The renewal of the point-to-point request is dependent on the upgrades the following facilities.

Reservation	Facility Name	COD	EOC
610383	WEST MCPHERSON - WHEATLAND 115KV CKT 1	6/1/2015	6/1/2015

Customer **Study Number**
KMEA AG2-2005-034

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974592	GRDA	KCPL	9	5/1/2006	5/1/2026	10/1/2007	10/1/2026	$ 31,659	$ -	$ 31,659	$ 87,759
									$ 31,659	$ -	$ 31,659	$ 87,759

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974592	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 3,957	$ 200,000	$ 11,057
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 19,787	$ 1,000,000	$ 54,588
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 7,915	$ 400,000	$ 22,114
			Total	$ 31,659	$ 1,600,000	$ 87,759

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974592	JEC - Swissvale 345KV	6/1/2011	6/1/2011

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974592	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974592	AEPW PLANNED UPGRADE FOR NW ARKANSAS	6/1/2006	6/1/2009
	LACYGNE-PAOLA-WEST GARDER 345KV	6/1/2006	6/1/2008

Customer **Study Number**
KMEA AG2-2005-035

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974596	GRDA	KCPL	6	5/1/2006	5/1/2026	10/1/2007	10/1/2026	$ 20,360	$ -	$ 20,360	$ 56,437
									$ 20,360	$ -	$ 20,360	$ 56,437

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974596	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 2,545	$ 200,000	$ 7,111
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 12,725	$ 1,000,000	$ 35,105
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 5,090	$ 400,000	$ 14,221
			Total	$ 20,360	$ 1,600,000	$ 56,437

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974596	JEC - Swissvale 345KV	6/1/2011	6/1/2011

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974596	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974596	AEPW PLANNED UPGRADE FOR NW ARKANSAS	6/1/2006	6/1/2009
	LACYGNE-PAOLA-WEST GARDER 345KV	6/1/2006	6/1/2008

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
KMEA AG2-2005-039

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974637	GRDA	WR	1	5/1/2009	5/1/2026			$ -	$ -	$ 25,576	$ 69,764
									$ -	$ -	$ 25,576	$ 69,764

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974637	SUB 110 - ORONOGO JCT. - SUB 167 - RIVERTON 161KV CKT 1	6/1/2011	6/1/2011	$ 25,576	$ 5,400,000	$ 69,764
			Total	$ 25,576	$ 5,400,000	$ 69,764

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974637	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Customer **Study Number**
KMEA AG2-2005-040

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974645	GRDA	WR	2	5/1/2009	5/1/2026			$ -	$ -	$ -	$ -
									$ -	$ -	$ -	$ -

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974645	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Customer **Study Number**
KMEA AG2-2005-041

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974650	GRDA	WR	3	5/1/2009	5/1/2026			$ -	$ 795,600	$ 12,699	$ 37,894
									$ -	$ 795,600	$ 12,699	$ 37,894

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974650	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 1,587	$ 200,000	$ 4,736
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 7,937	$ 1,000,000	$ 23,685
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 3,175	$ 400,000	$ 9,473
			Total	$ 12,699	$ 1,600,000	$ 37,894

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974650	JEC - Swissvale 345KV	6/1/2011	6/1/2011

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974650	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Customer **Study Number**
KMEA AG2-2005-042

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974656	GRDA	WR	3	5/1/2009	5/1/2026			$ -	$ 795,600	$ 12,488	$ 37,263
									$ -	$ 795,600	$ 12,488	$ 37,263

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974656	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 1,561	$ 200,000	$ 4,658
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 7,805	$ 1,000,000	$ 23,291
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 3,122	$ 400,000	$ 9,315
			Total	$ 12,488	$ 1,600,000	$ 37,263

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974656	27TH & CROCO - TECUMSEH HILL 115KV	6/1/2010	6/1/2010
	27TH & CROCO JUNCTION - 41ST & CALIFORNIA 115KV	6/1/2010	6/1/2010
	JEC - Swissvale 345KV	6/1/2011	6/1/2011

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974656	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer	**Study Number**
KMEA	AG2-2005-043

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date**	**Deferred Stop Date**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KMEA	974658	GRDA	WR	3	5/1/2006	5/1/2026	10/1/2006	10/1/2026	$ 540,000	$ 936,000	$ 1,128,617	$ 2,663,292
									$ 540,000	$ 936,000	$ 1,128,617	$ 2,663,292

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974658	AFTON (AFTAUTO1) 161/69/13.8KV TRANSFORMER CKT 1	12/1/2010	12/1/2010	$ 890,000	$ 890,000	$ 2,090,237
	SUB 110 - ORONOGO JCT. - SUB 167 - RIVERTON 161KV CKT 1	6/1/2011	6/1/2011	$ 238,617	$ 5,400,000	$ 573,055
			Total	$ 1,128,617	$ 6,290,000	$ 2,663,292

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974658	NEOSHO\ 138/69/12.47KV TRANSFORMER	6/1/2009	6/1/2009

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974658	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974658	AEPW PLANNED UPGRADE FOR NW ARKANSAS	6/1/2006	6/1/2009

Customer	**Study Number**
KMEA	AG2-2005-044

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date**	**Deferred Stop Date**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
KMEA	974660	GRDA	WR	3	5/1/2006	5/1/2026	10/1/2007	10/1/2026	$ 12,034	$ 936,000	$ 12,034	$ 33,358
									$ 12,034	$ 936,000	$ 12,034	$ 33,358

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974660	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 1,504	$ 200,000	$ 4,203
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 7,521	$ 1,000,000	$ 20,749
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 3,009	$ 400,000	$ 8,407
			Total	$ 12,034	$ 1,600,000	$ 33,358

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974660	CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1	4/1/2006	3/1/2007
	JEC - Swissvale 345KV	6/1/2011	6/1/2011
	TECUMSEH HILL () 161/115/13.8KV TRANSFORMER CKT 1	6/1/2010	6/1/2010

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974660	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974660	AEPW PLANNED UPGRADE FOR NW ARKANSAS	6/1/2006	6/1/2009
	LACYGNE-PAOLA-WEST GARDER 345KV	6/1/2006	6/1/2008

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
KMEA AG2-2005-058

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974976	GRDA	WPEK	3	5/1/2006	5/1/2026	10/1/2007	10/1/2026	$ 13,433	$ 704,160	$ 13,433	$ 37,236
									$ 13,433	$ 704,160	$ 13,433	$ 37,236

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974976	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 1,679	$ 200,000	$ 4,692
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 8,396	$ 1,000,000	$ 23,163
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 3,358	$ 400,000	$ 9,382
			Total	$ 13,433	$ 1,600,000	$ 37,236

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974976	CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1	4/1/2006	3/1/2007

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974976	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974976	AEPW PLANNED UPGRADE FOR NW ARKANSAS	6/1/2006	6/1/2009
	HEIZER - KNOLL 115KV	6/1/2006	6/1/2007
	LACYGNE-PAOLA-WEST GARDER 345KV	6/1/2006	6/1/2008
	RHOADES - PHILLIPSBURG 115KV	6/1/2006	6/1/2008

Customer **Study Number**
KMEA AG2-2005-059

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974977	GRDA	WPEK	2	5/1/2010	5/1/2026			$ 8,955	$ 375,552	$ 8,955	$ 28,216
									$ 8,955	$ 375,552	$ 8,955	$ 28,216

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974977	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 1,119	$ 200,000	$ 3,507
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 5,597	$ 1,000,000	$ 17,693
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 2,239	$ 400,000	$ 7,015
			Total	$ 8,955	$ 1,600,000	$ 28,216

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974977	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Customer **Study Number**
KMEA AG2-2005-063

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
KMEA	974926	GRDA	WPEK	1	5/1/2010	5/1/2026			$ 79,233	$ 187,776	$ 79,233	$ 243,441
									$ 79,233	$ 187,776	$ 79,233	$ 243,441

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974926	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 529	$ 200,000	$ 1,658
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 2,646	$ 1,000,000	$ 8,364
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 1,058	$ 400,000	$ 3,315
	WASHINGTON 1800 KVAR CAPACITOR	6/1/2010	6/1/2010	$ 75,000	$ 75,000	$ 230,104
			Total	$ 79,233	$ 1,675,000	$ 243,441

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
974926	JEC - Swissvale 345KV	6/1/2011	6/1/2011
	TECUMSEH HILL () 161/115/13.8KV TRANSFORMER CKT 1	6/1/2010	6/1/2010

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Reservation	Upgrade Name	COD	EOC
974926	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
SPSM AG2-2005-053

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date**	**Deferred Stop Date**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
SPSM	974790	CSWS	SPS	50	1/1/2007	1/1/2012			$ 415,956	$ 4,800,000	$ 415,956	$ 645,997
SPSM	974791	CSWS	SPS	50	1/1/2007	1/1/2012			$ 415,956	$ 4,800,000	$ 415,956	$ 645,997
SPSM	974793	CSWS	SPS	50	1/1/2007	1/1/2012			$ 415,956	$ 4,800,000	$ 415,956	$ 645,997
SPSM	974797	CSWS	SPS	50	1/1/2007	1/1/2012			$ 415,956	$ 4,800,000	$ 415,956	$ 645,997
									$ 1,663,824	$ 19,200,000	$ 1,663,824	$ 2,583,986

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
974790	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 45,630	$ 200,000	$ 74,653
	CACHE - SNYDER 138KV CKT 1	6/1/2008	6/1/2008	$ 2,913	$ 85,000	$ 4,943
	EAST CENTRAL HENRYETTA - OKMULGEE 138KV CKT 1	12/1/2006	12/1/2006	$ 27,000	$ 108,000	$ 41,250
	EAST CENTRAL HENRYETTA - WELEETKA 138KV CKT 1	6/1/2007	6/1/2007	$ 21,000	$ 84,000	$ 30,634
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 228,152	$ 1,000,000	$ 345,210
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 91,261	$ 400,000	$ 149,307
			Total	**$ 415,956**	**$ 1,877,000**	**$ 645,997**
974791	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 45,630	$ 200,000	$ 74,653
	CACHE - SNYDER 138KV CKT 1	6/1/2008	6/1/2008	$ 2,913	$ 85,000	$ 4,943
	EAST CENTRAL HENRYETTA - OKMULGEE 138KV CKT 1	12/1/2006	12/1/2006	$ 27,000	$ 108,000	$ 41,250
	EAST CENTRAL HENRYETTA - WELEETKA 138KV CKT 1	6/1/2007	6/1/2007	$ 21,000	$ 84,000	$ 30,634
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 228,152	$ 1,000,000	$ 345,210
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 91,261	$ 400,000	$ 149,307
			Total	**$ 415,956**	**$ 1,877,000**	**$ 645,997**
974793	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 45,630	$ 200,000	$ 74,653
	CACHE - SNYDER 138KV CKT 1	6/1/2008	6/1/2008	$ 2,913	$ 85,000	$ 4,943
	EAST CENTRAL HENRYETTA - OKMULGEE 138KV CKT 1	12/1/2006	12/1/2006	$ 27,000	$ 108,000	$ 41,250
	EAST CENTRAL HENRYETTA - WELEETKA 138KV CKT 1	6/1/2007	6/1/2007	$ 21,000	$ 84,000	$ 30,634
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 228,152	$ 1,000,000	$ 345,210
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 91,261	$ 400,000	$ 149,307
			Total	**$ 415,956**	**$ 1,877,000**	**$ 645,997**
974797	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	6/1/2009	6/1/2009	$ 45,630	$ 200,000	$ 74,653
	CACHE - SNYDER 138KV CKT 1	6/1/2008	6/1/2008	$ 2,913	$ 85,000	$ 4,943
	EAST CENTRAL HENRYETTA - OKMULGEE 138KV CKT 1	12/1/2006	12/1/2006	$ 27,000	$ 108,000	$ 41,250
	EAST CENTRAL HENRYETTA - WELEETKA 138KV CKT 1	6/1/2007	6/1/2007	$ 21,000	$ 84,000	$ 30,634
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	6/1/2009	6/1/2009	$ 228,152	$ 1,000,000	$ 345,210
	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	6/1/2009	6/1/2009	$ 91,261	$ 400,000	$ 149,307
			Total	**$ 415,956**	**$ 1,877,000**	**$ 645,997**

Customer **Study Number**
UCU AG2-2005-078

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date**	**Deferred Stop Date**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
UCU	977014	WPEK	MPS	20	7/1/2006	7/1/2017	10/1/2007	10/1/2018	$ -	$ 4,253,040	$ -	$ -
									$ -	$ 4,253,040	$ -	$ -

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
				$ -	$ -	$ -
			Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
977014	AVONDALE - GLADSTONE 161KV CKT 1	6/1/2011	6/1/2011
	JEC - Swissvale 345KV	6/1/2011	6/1/2011

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
977014	LACYGNE-PAOLA-WEST GARDER 345KV	6/1/2006	6/1/2008

Table 3 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated costs for Each Upgrade

Customer **Study Number**
UCU AG2-2005-079D

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
UCU	977018	WPEK	MPS	40	7/1/2006	7/1/2017	10/1/2006	10/1/2017	$ -	$ 8,506,080	$ -	$ -
									$ -	$ 8,506,080	$ -	$ -

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
				$ -	$ -	$ -
			Total	$ -	$ -	$ -

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
977018	JEC - Swissvale 345KV	6/1/2011	6/1/2011

No upgrade required. Redispatch Required to Prevent Deferral of Service.

Reservation	Upgrade Name	COD
977018	MARTIN CITY - TURNER ROAD SUBSTATION REDISPATCH	6/1/2006

Customer **Study Number**
WFEC AG2-2005-062

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
WFEC	971951	WFEC	WFEC	250	5/1/2010	5/1/2035			$ 13,613,991	$ -	$ 18,598,348	$ 55,506,772
									$ 13,613,991	$ -	$ 18,598,348	$ 55,506,772

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
971951	BROWN - EXPLORER TAP 138KV CKT 1	6/1/2008	6/1/2008	$ 25,000	$ 25,000	$ 115,240
	CACHE - SNYDER 138KV CKT 1	6/1/2008	6/1/2008	$ 73,348	$ 85,000	$ 348,355
	HUGO POWER PLANT - VALLIANT 345 KV AEPW	5/1/2010	5/1/2010	$ 2,500,000	$ 2,500,000	$ 10,339,521
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	5/1/2010	5/1/2010	$ 16,000,000	$ 16,000,000	$ 44,703,657
			Total	$ 18,598,348	$ 18,610,000	$ 55,506,772

Expansion Plan - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
971951	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	6/1/2015	6/1/2015
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 OKGE	6/1/2015	6/1/2015
	ELK CITY - ELK CITY 69KV CKT 1 AEPW	6/1/2008	6/1/2008
	FRANKLIN SW 138/69KV TRANSFORMER CKT 1	6/1/2011	6/1/2011
	Marietta Switch Capacitor	6/1/2010	6/1/2010
	PAOLI 138/69KV TRANSFORMER CKT 1	6/1/2009	6/1/2009

Construction Pending - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Reservation	Upgrade Name	COD	EOC
971951	CHICKASAW & CANEY CREEK CAPACITOR	6/1/2015	10/1/2006

Table 4 - Upgrade Requirements and Solutions Needed to Provide Transmission Service for the Aggregate Study

Transmission Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AEPW	CACHE - SNYDER 138KV CKT 1	Replace Snyder wavetrap	215	15SP	6/1/2008	6/1/2008	$ 85,000
AEPW	EAST CENTRAL HENRYETTA - OKMULGEE 138KV CKT 1	Replace Okmulgee Wavetrap	0	07SP	12/1/2006	12/1/2006	$ 108,000
AEPW	EAST CENTRAL HENRYETTA - WELEETKA 138KV CKT 1	Replace Weleetka Wavetrap	0	07SP	6/1/2007	6/1/2007	$ 84,000
AEPW	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 AEPW	Reconductor 1.9 miles with ACCC. Replace wave trap jumpers at Riverside.	0	10SP	6/1/2009	6/1/2009	$ 1,000,000
AEPW	FULTON - HOPE 115KV CKT 1	Replace conductor in Hope Substation	0	10SP	6/1/2010	6/1/2010	$ 125,000
AEPW	HUGO POWER PLANT - VALLIANT 345 KV AEPW	Vallient 345 KV line terminal	0	10SP	5/1/2010	5/1/2010	$ 2,500,000
EMDE	Nichols St. Sub Bus - Nichols St. Sub 69KV	New connection between EDE Nichols St. Sub Bus # 59542 and Springfield City Utilities Nichols St. Sub #59925	82	15SP	6/1/2015	6/1/2015	$ 1,000,000
EMDE	SUB 110 - ORONOGO JCT. - SUB 167 - RIVERTON 161KV CKT 1	Reconductor Oronogo 59467 to Riverton 59469 with Bundled 556 ACSR	54	15SP	6/1/2011	6/1/2011	$ 5,400,000
EMDE	SUB 110 - ORONOGO JCT. (ORONOGO) 161/69/12.5KV TRANSFORMER CKT 1	Installl new 161/12 kV 22.4 transmer and take load off 69 kV system	54	15SP	6/1/2011	6/1/2011	$ 2,000,000
GRDA	AFTON (AFTAUTO1) 161/69/13.8KV TRANSFORMER CKT 1	Replace 50 MVA Transformer with 84 MVA unit.	0	10WP	12/1/2010	12/1/2010	$ 890,000
MIPU	MARTIN CITY - TURNER ROAD SUBSTATION REDISPATCH	Redispatch required to prevent deferral of service	0	06SP	6/1/2006		$ -
OKGE	BEELINE - EXPLORER GLENPOOL 138KV CKT 1	Reconductor .92miles of line with Drake ACCC/TW.	0	10SP	6/1/2009	6/1/2009	$ 200,000
OKGE	BROWN - EXPLORER TAP 138KV CKT 1	Upgrade CT to 800A at Brown.	19	15SP	6/1/2008	6/1/2008	$ 25,000
OKGE	EXPLORER GLENPOOL - RIVERSIDE STATION 138KV CKT 1 OKGE	Reconductor 1.82 miles line with Drake ACCC/TW.	0	10SP	6/1/2009	6/1/2009	$ 400,000
WERE	NORTH AMERICAN PHILIPS - NORTH AMERICAN PHILIPS JUNCTION (SOUTH) 115KV CKT 1	Redispatch required	0	10WP	6/1/2009		$ -
WERE	NORTH AMERICAN PHILIPS JUNCTION (SOUTH) - WEST MCPHERSON 115KV CKT 1	Redispatch required	0	10WP	6/1/2009		$ -
WFEC	HUGO POWER PLANT - VALLIANT 345 KV WFEC	New 345/138 kv Auto, and 19 miles 345 KV	0	10SP	5/1/2010	5/1/2010	$ 16,000,000
WPEK	WASHINGTON 1800 KVAR CAPACITOR	Install 1800 kVar outside the city of Washington sub	0	10SP	6/1/2010	6/1/2010	$ 75,000

Construction Pending Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	AEPW PLANNED UPGRADE FOR NW ARKANSAS	NW Project phase II scheduled to be in-service 06/2009	0	06SP	6/1/2006	6/1/2009
KACP	LACYGNE-PAOLA-WEST GARDER 345KV	New 345/161kV transformer and 345kV line tapping LaCyne - West Gardner 345kV	0	06SH	6/1/2006	6/1/2008
MIDW	RHOADES - PHILLIPSBURG 115KV	Construct Rhoades to Phillipsburg 56373 to 58785	0	07SP	6/1/2006	6/1/2008
OKGE	CHICKASAW & CANEY CREEK CAPACITOR	OGE has budgeted for 2006 30Mvar of 138kV caps at each of the following locations: Chickasaw Bus # 55171, Caney Creek Bus 55150.	229	15SP	6/1/2015	10/1/2006
WEPL	HEIZER - KNOLL 115KV		0	06SP	6/1/2006	6/1/2007
WEPL	RHOADES - PHILLIPSBURG 115KV	Construct Rhoades to Phillipsburg 56373 to 58785	0	07SP	6/1/2006	6/1/2008
WERE	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1	Tear down and rebuild 7.22 mile Jarbalo-166 115 kV line.	0	10SP	6/1/2013	6/1/2013

Expansion Plan Projects - The requested service is contingent upon completion of the following upgrades. Cost is not assignable to the transmission customer.

Transmission Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	Rebuild 2.54 miles with 2-795 ACSR & reset Clarksville CT, Replace Switches & Breakers @ Clarksville.	0	15SP	6/1/2015	6/1/2015
AEPW	ELK CITY - ELK CITY 69KV CKT 1 AEPW	Replace CTS & jumpers	0	10SP	6/1/2008	6/1/2008
EMDE	RIVERSIDE CAPACITOR	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 59497	77	15SP	6/1/2015	6/1/2015
EMDE	SUB 389 - JOPLIN SOUTHWEST - SUB EXPLORER SPRING CITY TAP 69KV CKT 1	Reconductor 69 kV line from 59438 to 59592 with 556 ACSR Lindy at 59563 is droped for contingency	0	10SP	6/1/2008	6/1/2009
EMDE	SUB 389 - JOPLIN SOUTHWEST (JOPLINSW) 161/69/12.5KV TRANSFORMER CKT 1	Replace 75 MVA Auto-xfmr at Joplin SW with 150 MVA Auto-xfmr and install 69 kV bank breaker. Auto-xfmr will have an impedance similar to Aurora 59468, 59537, 59704.	112	15SP	6/1/2011	6/1/2011
KACP	AVONDALE - GLADSTONE 161KV CKT 1	Replace 800 amp wavetrap at Gladstone with 1200 amp wavetrap	0	15SP	6/1/2011	6/1/2011
OKGE	CLARKSVILLE - MUSKOGEE 345KV CKT 1 OKGE	Change 2-345kV breakers to 3000A, a trap to 3000A, 5 switches to 3000A, and 2 differential relays	0	15SP	6/1/2015	6/1/2015
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1 SWPA	Replace three 600A switches @ Bull Shoals w/ 1200 A switches. Resag conductor and replace structures as necessary to achieve 195 MW rating.	74	15SP	6/1/2011	6/1/2011
WERE	166TH STREET - JAGGARD JUNCTION 115KV CKT 1	Tear down and rebuild 3.66 mile 166-Jaggard 115 kV line.	0	10SP	6/1/2013	6/1/2013
WERE	27TH & CROCO - TECUMSEH HILL 115KV	Tear down and rebuild 2.72 mile Tecumseh Hill-27th & Croco 115 kV line as a single circuit.	0	10SP	6/1/2010	6/1/2010
WERE	27TH & CROCO JUNCTION - 41ST & CALIFORNIA 115KV	Tear down and rebuild 3.43 mile 27th & Croco-41st & California 115 kV line as a single circuit.	0	10SP	6/1/2010	6/1/2010
WERE	CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1	Rebuild 15.50 mile Circleville-Hoyt HTI Junction 115 kV line.	0	06FA	4/1/2006	3/1/2007
WERE	JEC - Swissvale 345KV	Construct JEC-Swissvale 345 kV line.	0	15SP	6/1/2011	6/1/2011
WERE	NEOSHO\ 138/69/12.47KV TRANSFORMER	Replace the three Neosho 138-69 kV #2 transformers (#2A, #2B, #2C) with one 85 MVA transformer.	0	10SP	6/1/2009	6/1/2009
WERE	TECUMSEH HILL () 161/115/13.8KV TRANSFORMER CKT 1	Move the Midland Jct. 161-115 kV transformer to Tecumseh Hill.	0	15SP	6/1/2010	6/1/2010
WFEC	FRANKLIN SW 138/69KV TRANSFORMER CKT 1	Replace 70 MVA Auto with 112 MVA autotranformer (100 MVA base Rating), Upgrade 138 and 69 KV buswork and switches.	68	15SP	6/1/2011	6/1/2011
WFEC	Marietta Switch Capacitor	12 MVAR at Marietta Switch	227	10SP	6/1/2010	6/1/2010
WFEC	PAOLI 138/69KV TRANSFORMER CKT 1	Upgrade auto to 70 MVA	67	15SP	6/1/2009	6/1/2009

Credits may be required for the following network upgrades directly assigned to transmission customers in previous aggregate study.

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
GRDA	412SUB - KANSAS TAP 161KV CKT 1	Reconductor 9.7 miles with 1590MCM ACSR.	6/1/2015	6/1/2015	$1,488,000
GRDA	412SUB - KERR 161KV CKT 1	Reconductor 12.5 miles with 1590MCM ACSR	6/1/2015	6/1/2015	$1,918,000

Rollover Right Limitations for Point-to-Point Requests

Transmission Owner	Limiting Facility	Earliest Date Upgrade Required (COD)
WERE	WEST MCPHERSON - WHEATLAND 115KV CKT 1	6/1/2015

Table 5 - Third Party Facility Constraints

Transmission Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Date Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
ENTR	3BISMRK - 3HSEHVW 115KV CKT 1	Murfreesboro South Project	0	06SP	6/1/2006	6/1/2008	$ 18,000,000

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1
Limiting Facility: CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1
Direction: To->From
Line Outage: IATAN - ST JOE 345KV CKT 1
Flowgate: 57152571651579825919912106FA
Date Redispatch N(10/1/06-12/1/06

Reservation	Relief Amount	Aggregate Relief Amount
974660	2.0	2.0

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WEPL	CLIFTON GENERATOR	1	70.0	-0.09746	WEPL	JUDSON LARGE GENERATOR	4	45.0	0.00338	-0.10084	20
WERE	GETTY	1	35.0	-0.00292	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.0521	39
WERE	GETTY	1	35.0	-0.00292	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.0521	39
WERE	GETTY	1	35.0	-0.00292	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.04364	46
WERE	GETTY	1	35.0	-0.00292	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.04364	46
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.00822	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.04096	49
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.00822	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.04096	49
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00816	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.04102	49
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00816	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.04102	49
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00816	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.04102	49
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00816	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.04102	49
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00825	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.04093	49
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00825	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.04093	49
WERE	GETTY	1	35.0	-0.00292	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.03783	-0.04075	50
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00953	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.03965	51
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00954	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.03964	51
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00954	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.03964	51
WERE	EVANS ENERGY CENTER UNIT 2	1	109.1	0.00954	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04918	-0.03964	51
WERE	EVANS ENERGY CENTER UNIT 2	1	109.1	0.00954	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	68.0	0.04918	-0.03964	51
WERE	GETTY	1	35.0	-0.00292	WERE	LAWRENCE ENERGY CENTER UNIT 3	1	25.0	0.03443	-0.03735	54
WERE	GETTY	1	35.0	-0.00292	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.03451	-0.03743	54
WERE	GETTY	1	35.0	-0.00292	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.0	0.03428	-0.0372	54
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.00822	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.0325	62
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.00822	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.0325	62
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00816	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03256	62
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00816	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03256	62
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00816	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03256	62
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00816	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03256	62
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00825	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03247	62
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00825	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03247	62
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00954	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03118	65
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00954	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03118	65
WERE	EVANS ENERGY CENTER UNIT 2	1	109.1	0.00954	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03118	65
WERE	EVANS ENERGY CENTER UNIT 2	1	109.1	0.00954	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03118	65
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03119	65
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03119	65
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03119	65
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03119	65
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04072	-0.03119	65
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00953	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04072	-0.03119	65

Maximum Decrement and Maximum Increment were determine from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1
Limiting Facility: CIRCLEVILLE - HOYT HTI SWITCHING JUNCTION 115KV CKT 1
Direction: To->From
Line Outage: IATAN - ST JOE 345KV CKT 1
Flowgate: 57152571651579825919913106WP
Date Redispatch N(12/1/06-4/1/07

Reservation	Relief Amount	Aggregate Relief Amount
974660	0.5	0.5

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WEPL	CLIFTON GENERATOR	1	70.0	-0.09754	WEPL	JUDSON LARGE GENERATOR	4	45.4	0.00332	-0.10086	5
WEPL	CLIFTON GENERATOR	1	70.0	-0.09754	WEPL	A. M. MULLERGREN GENERATOR	3	16.0	0.00866	-0.1062	5
WERE	GETTY	1	35.0	-0.00295	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.05208	9
WERE	GETTY	1	35.0	-0.00295	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.05208	9
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00813	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.041	12
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00813	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.041	12
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00813	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.041	12
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00813	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.041	12
WERE	GETTY	1	35.0	-0.00295	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.04363	11
WERE	GETTY	1	35.0	-0.00295	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.04363	11
WERE	CHANUTE GENERATION SUB	1	21.9	0.00753	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.0416	12
WERE	CHANUTE GENERATION SUB	1	21.9	0.00753	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.0416	12
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.0082	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.04093	12
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.0082	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.04093	12
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00952	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.03961	12
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00952	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.03961	12
WERE	EVANS ENERGY CENTER UNIT 2	1	256.8	0.00952	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.03961	12
WERE	EVANS ENERGY CENTER UNIT 2	1	256.8	0.00952	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.03961	12
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.03962	12
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.03962	12
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.03962	12
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.03962	12
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.03962	12
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00951	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.03962	12
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00823	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.0409	12
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00823	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.0409	12
WERE	GILL ENERGY CENTER UNIT 4	1	106.0	0.00826	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.04913	-0.04087	12
WERE	GILL ENERGY CENTER UNIT 4	1	106.0	0.00826	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.04913	-0.04087	12
WERE	GETTY	1	35.0	-0.00295	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.03778	-0.04073	12
WERE	GETTY	1	35.0	-0.00295	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	175.5	0.03424	-0.03719	13
WERE	CHANUTE GENERATION SUB	1	21.9	0.00753	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03315	15
WERE	CHANUTE GENERATION SUB	1	21.9	0.00753	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03315	15
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.0082	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03248	15
WERE	NEOSHO ENERGY CENTER UNIT 3	1	67.0	0.0082	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03248	15
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00952	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03116	16
WERE	EVANS ENERGY CENTER UNIT 1	1	151.0	0.00952	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03116	16
WERE	EVANS ENERGY CENTER UNIT 2	1	256.8	0.00952	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03116	16
WERE	EVANS ENERGY CENTER UNIT 2	1	256.8	0.00952	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03116	16
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03117	16
WERE	EVANS ENERGY CENTER GAS TURBINE 1	1	80.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03117	16
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03117	16
WERE	EVANS ENERGY CENTER GAS TURBINE 2	1	80.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03117	16
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03117	16
WERE	EVANS ENERGY CENTER GAS TURBINE 3	1	154.0	0.00951	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03117	16
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00813	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03255	15
WERE	GILL ENERGY CENTER UNIT 1	1	44.0	0.00813	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03255	15
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00813	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03255	15
WERE	GILL ENERGY CENTER UNIT 2	1	74.0	0.00813	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03255	15
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00823	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03245	15
WERE	GILL ENERGY CENTER UNIT 3	1	112.0	0.00823	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03245	15
WERE	GILL ENERGY CENTER UNIT 4	1	106.0	0.00826	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.04068	-0.03242	15
WERE	GILL ENERGY CENTER UNIT 4	1	106.0	0.00826	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.04068	-0.03242	15
WERE	CHANUTE GENERATION SUB	1	21.9	0.00753	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.03778	-0.03025	16

Maximum Decrement and Maximum Increment were determine from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: LACYGNE-PAOLA-WEST GARDER 345KV
Limiting Facility: WEST GARDNER (WGARD 11) 345/161/13.8KV TRANSFORMER CKT 11
Direction: From->To
Line Outage: CRAIG - WEST GARDNER 345KV CKT 1
Flowgate: W#GARD 11175115797757965121 06SH
Date Redispatch N(6/1/06-10/1/06

Reservation	Relief Amount	Aggregate Relief Amount
977014	0.9	0.9

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	2
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	2
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	2
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	2
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	2
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	2
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	2
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	2
KACP	GARDNER	1	11.0	-0.29277	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.41967	2
KACP	GARDNER	1	11.0	-0.29277	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.41967	2
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	3
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	3
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	3
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	3
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	3
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.25936	3
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.25936	3
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.25936	3
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.2372	4
KACP	GARDNER	1	11.0	-0.29277	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.23299	4
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.2372	4
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.23667	4
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.2372	4
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.22898	4
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.22898	4
KACP	NORTHEAST CT #11	1	56.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #11	1	56.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.0647	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.1916	5
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.0647	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.1916	5
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.0647	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.1916	5
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.0647	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.1916	5
KACP	NORTHEAST CT #13	1	56.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #13	1	56.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #14	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #14	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #15	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #15	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #16	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #16	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #17	1	59.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #17	1	59.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #18	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	5
KACP	NORTHEAST CT #18	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	5
KACP	HAWTHORN COMBUSTION TURBINE #7	7	31.3	-0.0561	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.183	5
KACP	HAWTHORN COMBUSTION TURBINE #7	7	31.3	-0.0561	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.183	5
KACP	HAWTHORN COMBUSTION TURBINE #8	8	77.0	-0.0561	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.183	5
KACP	HAWTHORN COMBUSTION TURBINE #8	8	77.0	-0.0561	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.183	5
KACP	CITY OF HIGGINSVILLE	1	36.0	-0.02901	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.15591	6
KACP	CITY OF HIGGINSVILLE	1	36.0	-0.02901	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.15591	6
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.07397	12
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.07386	12
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.07295	12
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.06867	13
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.06867	13
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.06867	13
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06199	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06188	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	15
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06097	15
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	15
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	15
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	15
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	15

Maximum Decrement and Maximum Increment were determined from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: LACYGNE-PAOLA-WEST GARDER 345KV
Limiting Facility: WEST GARDNER (WGARD 11) 345/161/13.8KV TRANSFORMER CKT 11
Direction: From->To
Line Outage: CRAIG - WEST GARDNER 345KV CKT 1
Flowgate: W#GARD 11175115797757965121O6SH
Date Redispatch N(6/1/07-10/1/07

Reservation	Relief Amount	Aggregate Relief Amount
974592	3.4	5.9
974596	1.5	5.9
974660	0.2	5.9
977014	0.9	5.9

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	12
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	12
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	12
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	12
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	12
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	12
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.4831	12
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.4831	12
KACP	GARDNER	1	11.0	-0.29277	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.41967	14
KACP	GARDNER	1	11.0	-0.29277	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.41967	14
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	18
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.32279	18
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.32279	18
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.32279	18
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	20
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	20
KACP	BULL CREEK COMBUSTION TURBINE #1	1	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	20
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	20
KACP	BULL CREEK COMBUSTION TURBINE #2	2	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	20
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	20
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	20
KACP	BULL CREEK COMBUSTION TURBINE #3	3	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	20
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.30063	20
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.29642	20
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.30063	20
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.3001	20
KACP	BULL CREEK CT #4	4	77.0	-0.3562	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.30063	20
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.25936	23
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.25936	23
KACP	GARDNER	1	11.0	-0.29277	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.25936	23
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN UNIT #5	5	457.0	-0.05557	-0.2372	25
KACP	GARDNER	1	11.0	-0.29277	KACP	IATAN UNIT #1	1	390.0	-0.05978	-0.23299	25
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN COMBUSTION TURBINE #6	6	92.0	-0.05557	-0.2372	25
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN COMBUSTION TURBINE #7	7	45.7	-0.0561	-0.23667	25
KACP	GARDNER	1	11.0	-0.29277	KACP	HAWTHORN UNIT #9	9	68.0	-0.05557	-0.2372	25
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.22898	26
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.22898	26
KACP	NORTHEAST CT #11	1	56.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #11	1	56.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.0647	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.1916	31
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.0647	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.1916	31
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.0647	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.1916	31
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.0647	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.1916	31
KACP	NORTHEAST CT #13	1	56.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #13	1	56.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #14	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #14	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #15	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #15	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #16	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #16	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #17	1	59.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #17	1	59.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #18	1	58.0	-0.06294	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.18984	31
KACP	NORTHEAST CT #18	1	58.0	-0.06294	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.18984	31
KACP	HAWTHORN COMBUSTION TURBINE #7	7	31.3	-0.0561	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.183	32
KACP	HAWTHORN COMBUSTION TURBINE #7	7	31.3	-0.0561	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.183	32
KACP	HAWTHORN COMBUSTION TURBINE #8	8	77.0	-0.0561	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.183	32
KACP	HAWTHORN COMBUSTION TURBINE #8	8	77.0	-0.0561	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.183	32
KACP	CITY OF HIGGINSVILLE	1	36.0	-0.02901	KACP	LACYGNE UNIT #1	1	469.0	0.1269	-0.15591	38
KACP	CITY OF HIGGINSVILLE	1	36.0	-0.02901	KACP	LACYGNE UNIT #2	2	469.0	0.1269	-0.15591	38
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.07397	80
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.07386	80
WERE	LAWRENCE ENERGY CENTER UNIT 5	1	44.0	-0.03157	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.07295	81
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #1	1	127.0	-0.03341	-0.06867	86
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #2	2	121.0	-0.03341	-0.06867	86
KACP	PAOLA COMBUSTION TURBINES	1	77.0	-0.10208	KACP	MONTROSE UNIT #3	3	127.3	-0.03341	-0.06867	86
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06197	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06186	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.06199	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	GILL ENERGY CENTER UNIT 4	1	77.0	0.04229	-0.06188	95
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	97
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	97
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.01957	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06095	97
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.01959	WERE	EVANS ENERGY CENTER UNIT 2	1	305.0	0.04138	-0.06097	97
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	98
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	98
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	98
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.01756	WERE	GILL ENERGY CENTER UNIT 3	1	78.0	0.0424	-0.05996	98

Maximum Decrement and Maximum Increment were determined from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: N/A
Limiting Facility: MARTIN CITY - TURNER ROAD SUBSTATION 161KV CKT 1
Direction: To->From
Line Outage: GRD OAK - PLEASANT HILL 345KV CKT 1
Flowgate: 59210592591591985920013106SP
Date Redispatch N 6/1/06-10/1/06

Reservation	Relief Amount	Aggregate Relief Amount
977018	1.4	1.4

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
MIPU	SIBLEY GENERATING UNIT #3	3	20.1	-0.03203	MIPU	SHARPR#1	1	105.0	0.38755	-0.41958	3
MIPU	SIBLEY GENERATING UNIT #3	3	20.1	-0.03203	MIPU	SHARPR#2	2	105.0	0.38755	-0.41958	3
MIPU	SIBLEY GENERATING UNIT #3	3	20.1	-0.03203	MIPU	SHARPR#3	3	105.0	0.38755	-0.41958	3
MIPU	GREENWOOD GENERATING UNIT #1	1	63.8	-0.04535	MIPU	SHARPR#1	1	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #1	1	63.8	-0.04535	MIPU	SHARPR#2	2	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #1	1	63.8	-0.04535	MIPU	SHARPR#3	3	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #2	2	64.0	-0.04535	MIPU	SHARPR#1	1	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #2	2	64.0	-0.04535	MIPU	SHARPR#2	2	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #2	2	64.0	-0.04535	MIPU	SHARPR#3	3	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #3	3	42.1	-0.04535	MIPU	SHARPR#1	1	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #3	3	42.1	-0.04535	MIPU	SHARPR#2	2	105.0	0.38755	-0.4329	3
MIPU	GREENWOOD GENERATING UNIT #3	3	42.1	-0.04535	MIPU	SHARPR#3	3	105.0	0.38755	-0.4329	3
MIPU	NEVADA GENERATING UNIT #1	1	20.3	-0.00985	MIPU	SHARPR#1	1	105.0	0.38755	-0.3974	3
MIPU	NEVADA GENERATING UNIT #1	1	20.3	-0.00985	MIPU	SHARPR#2	2	105.0	0.38755	-0.3974	3
MIPU	NEVADA GENERATING UNIT #1	1	20.3	-0.00985	MIPU	SHARPR#3	3	105.0	0.38755	-0.3974	3
MIPU	TWA#1	1	14.6	-0.02373	MIPU	SHARPR#1	1	105.0	0.38755	-0.41128	3
MIPU	TWA#1	1	14.6	-0.02373	MIPU	SHARPR#2	2	105.0	0.38755	-0.41128	3
MIPU	TWA#1	1	14.6	-0.02373	MIPU	SHARPR#3	3	105.0	0.38755	-0.41128	3
MIPU	TWA#2	1	17.5	-0.02373	MIPU	SHARPR#1	1	105.0	0.38755	-0.41128	3
MIPU	TWA#2	1	17.5	-0.02373	MIPU	SHARPR#2	2	105.0	0.38755	-0.41128	3
MIPU	TWA#2	1	17.5	-0.02373	MIPU	SHARPR#3	3	105.0	0.38755	-0.41128	3
MIPU	ARIES STEAM TURBINE	1	265.0	-0.04243	MIPU	SHARPR#1	1	105.0	0.38755	-0.42998	3
MIPU	ARIES STEAM TURBINE	1	265.0	-0.04243	MIPU	SHARPR#2	2	105.0	0.38755	-0.42998	3
MIPU	ARIES STEAM TURBINE	1	265.0	-0.04243	MIPU	SHARPR#3	3	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #1	1	21.0	-0.04243	MIPU	SHARPR#1	1	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #1	1	21.0	-0.04243	MIPU	SHARPR#2	2	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #1	1	21.0	-0.04243	MIPU	SHARPR#3	3	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #2	1	165.0	-0.04243	MIPU	SHARPR#1	1	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #2	1	165.0	-0.04243	MIPU	SHARPR#2	2	105.0	0.38755	-0.42998	3
MIPU	ARIES COMBUSTION TURBINE #2	1	165.0	-0.04243	MIPU	SHARPR#3	3	105.0	0.38755	-0.42998	3
MIPU	LAKE ROAD	1	135.0	-0.01533	MIPU	SHARPR#1	1	105.0	0.38755	-0.40288	3
MIPU	LAKE ROAD	1	135.0	-0.01533	MIPU	SHARPR#2	2	105.0	0.38755	-0.40288	3
MIPU	LAKE ROAD	1	135.0	-0.01533	MIPU	SHARPR#3	3	105.0	0.38755	-0.40288	3
MIPU	RALPH GREEN GENERATING UNIT #3	3	73.7	0.07664	MIPU	SHARPR#1	1	105.0	0.38755	-0.31091	4
MIPU	RALPH GREEN GENERATING UNIT #3	3	73.7	0.07664	MIPU	SHARPR#2	2	105.0	0.38755	-0.31091	4
MIPU	RALPH GREEN GENERATING UNIT #3	3	73.7	0.07664	MIPU	SHARPR#3	3	105.0	0.38755	-0.31091	4
KACP	NORTHEAST CT #11	1	43.2	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #11	1	43.2	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST COMBUSTINE TURBINES NORTH	1	55.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.02807	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.06784	20
KACP	GRAND AVENUE COMBUSTINE TURBINES	7	33.0	-0.02807	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.06784	20
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.02807	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.06784	20
KACP	GRAND AVENUE COMBUSTINE TURBINES	9	32.0	-0.02807	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.06784	20
KACP	NORTHEAST CT #13	1	56.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #13	1	56.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #14	1	58.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #14	1	58.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #15	1	58.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #15	1	58.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #16	1	58.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #16	1	58.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #17	1	59.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #17	1	59.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #18	1	58.0	-0.02843	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.0682	20
KACP	NORTHEAST CT #18	1	58.0	-0.02843	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.0682	20
KACP	GARDNER	1	11.0	-0.00622	KACP	LACYGNE UNIT #1	1	469.0	0.03977	-0.04599	30
KACP	GARDNER	1	11.0	-0.00622	KACP	LACYGNE UNIT #2	2	469.0	0.03977	-0.04599	30
MIPU	GREENWOOD GENERATING UNIT #1	1	63.8	-0.04535	MIPU	LAKE ROAD	1	117.0	-0.01533	-0.03002	46
MIPU	GREENWOOD GENERATING UNIT #2	2	64.0	-0.04535	MIPU	LAKE ROAD	1	117.0	-0.01533	-0.03002	46
MIPU	GREENWOOD GENERATING UNIT #3	3	42.1	-0.04535	MIPU	LAKE ROAD	1	117.0	-0.01533	-0.03002	46

Maximum Decrement and Maximum Increment were determined from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: N/A
Limiting Facility: NORTH AMERICAN PHILIPS - NORTH AMERICAN PHILIPS JUNCTION (SOUTH) 115KV CKT 1
Direction: From->To
Line Outage: EAST MCPHERSON - SUMMIT 230KV CKT 1
Flowgate: 57372573741568725687312210WP
Date Redispatch N(12/1/09-4/1/10

Reservation	Relief Amount	Aggregate Relief Amount
610383	1.8	1.8

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.51211	3
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.51357	3
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.51357	3
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.50317	3
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.50317	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.5509	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.5395	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.54034	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.52153	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	WACO	1	18.0	-0.0029	-0.51894	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.51999	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.5207	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.52184	WERE	CITY OF ERIE	1	20.0	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.5509	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.5395	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.54034	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.52153	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	WACO	1	18.0	-0.0029	-0.51894	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.51999	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.5207	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.52184	WERE	CITY OF ERIE	1	20.0	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.5509	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.5395	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.54034	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.52153	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	WACO	1	18.0	-0.0029	-0.51894	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.51999	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.5207	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.52184	WERE	CITY OF ERIE	1	20.0	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.5509	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.55236	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.5395	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.54034	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.54196	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.52153	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	WACO	1	18.0	-0.0029	-0.51894	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.51999	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.5207	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.52184	WERE	CITY OF ERIE	1	20.0	0.00261	-0.52445	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.53761	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.53907	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.53907	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.52621	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.52705	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.52867	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.52867	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.50824	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	WACO	1	18.0	-0.0029	-0.50565	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.5067	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.50741	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.51116	3
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.50855	WERE	CITY OF ERIE	1	20.0	0.00261	-0.51116	3
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.50071	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.50155	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.48274	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	WACO	1	18.0	-0.0029	-0.48015	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.4812	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.48191	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.48566	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.48305	WERE	CITY OF ERIE	1	20.0	0.00261	-0.48566	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.49342	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.49488	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.49488	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.48202	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.48286	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.48448	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.48448	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.46405	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	WACO	1	18.0	-0.0029	-0.46146	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.46251	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.46322	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.46697	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.46436	WERE	CITY OF ERIE	1	20.0	0.00261	-0.46697	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43088	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41948	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42032	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40151	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	WACO	1	18.0	-0.0029	-0.39892	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.39997	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40068	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.40182	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43088	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41948	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42032	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40151	4

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	WACO	1	18.0	-0.0029	-0.39892	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.39997	4

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40068	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.40182	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43088	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43234	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41948	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42032	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42194	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40151	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	WACO	1	18.0	-0.0029	-0.39892	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.39997	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40068	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.40182	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40443	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43155	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43301	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43301	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.42015	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42099	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42261	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42261	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40218	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	WACO	1	18.0	-0.0029	-0.39959	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.40064	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40135	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.4051	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.40249	WERE	CITY OF ERIE	1	20.0	0.00261	-0.4051	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43128	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41988	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42072	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40191	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	WACO	1	18.0	-0.0029	-0.39932	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.40037	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40108	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.40222	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43128	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41988	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42072	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40191	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	WACO	1	18.0	-0.0029	-0.39932	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.40037	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40108	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.40222	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43128	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41988	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42072	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40191	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	WACO	1	18.0	-0.0029	-0.39932	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.40037	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40108	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.40222	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.43128	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.43274	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.41988	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.42072	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.42234	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.40191	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	WACO	1	18.0	-0.0029	-0.39932	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.40037	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.40108	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.40483	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.40222	WERE	CITY OF ERIE	1	20.0	0.00261	-0.40483	4
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.02906	-0.2433	7
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.03052	-0.24476	7
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.03052	-0.24476	7
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.01766	-0.2319	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.0185	-0.23274	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.02012	-0.23436	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.02012	-0.23436	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00031	-0.21393	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	WACO	1	18.0	-0.0029	-0.21134	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	CITY OF WELLINGTON	1	14.3	-0.00185	-0.21239	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	CITY OF WINFIELD	1	24.6	-0.00114	-0.2131	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	CHANUTE GENERATION SUB	1	24.5	0.00261	-0.21685	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.21424	WERE	CITY OF ERIE	1	20.0	0.00261	-0.21685	8

Maximum Decrement and Maximum Increment were determined from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

Upgrade: N/A
Limiting Facility: NORTH AMERICAN PHILIPS JUNCTION (SOUTH) - WEST MCPHERSON 115KV CKT 1
Direction: From->To
Line Outage: EAST MCPHERSON - SUMMIT 230KV CKT 1
Flowgate: 57374574381568725687312210WP
Date Redispatch Ne 12/1/09-4/1/10

Reservation	Relief Amount	Aggregate Relief Amount
610383	0.9	0.9

Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.23814	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.23882	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.23882	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.23284	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.23324	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.23398	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.23398	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.22448	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	WACO	1	18.0	-0.00135	-0.22328	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.22377	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.2241	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.22584	4
WERE	LYONS (KMEA Municipal Sterling)	KS		-0.22463	WERE	CITY OF ERIE	1	20.0	0.00121	-0.22584	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.22945	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.23013	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.23013	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.22415	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.22455	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.22529	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.22529	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.21579	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	WACO	1	18.0	-0.00135	-0.21459	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.21508	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.21541	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.21715	4
WERE	RICE COUNTY (KMEA Municipal Ellinwood)	KE		-0.21594	WERE	CITY OF ERIE	1	20.0	0.00121	-0.21715	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20037	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20037	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20037	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20105	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20068	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20136	4
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20136	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20055	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20055	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20055	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.20055	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.20123	4
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.20123	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.25618	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.25088	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.25128	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.24252	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	WACO	1	18.0	-0.00135	-0.24132	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.24181	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.24214	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON STEAM PLANT	1	27.0	-0.24267	WERE	CITY OF ERIE	1	20.0	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.25618	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.25088	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.25128	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.24252	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	WACO	1	18.0	-0.00135	-0.24132	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.24181	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.24214	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 1	1	51.0	-0.24267	WERE	CITY OF ERIE	1	20.0	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.25618	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.25088	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.25128	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.24252	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	WACO	1	18.0	-0.00135	-0.24132	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.24181	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.24214	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 2	1	52.0	-0.24267	WERE	CITY OF ERIE	1	20.0	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.25618	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.25686	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.25088	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.25128	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.25202	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.24252	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	WACO	1	18.0	-0.00135	-0.24132	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.24181	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.24214	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 3	1	50.0	-0.24267	WERE	CITY OF ERIE	1	20.0	0.00121	-0.24388	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.25	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.25068	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.25068	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.2447	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.2451	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.24584	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.24584	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.23634	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	WACO	1	18.0	-0.00135	-0.23514	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.23563	4

Table 6 - Potential Redispatch Relief Pairs to Prevent Deferral of Service

WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.23596	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.2377	4
WERE	BPU - CITY OF MCPHERSON GAS TURBINE 4	1	79.0	-0.23649	WERE	CITY OF ERIE	1	20.0	0.00121	-0.2377	4
Source Control Area	Source	Source Id	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Sink Id	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19507	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19547	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18671	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	WACO	1	18.0	-0.00135	-0.18551	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.186	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18633	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 1	1	18.0	-0.18686	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19507	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19547	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18671	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	WACO	1	18.0	-0.00135	-0.18551	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.186	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18633	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 2	1	18.0	-0.18686	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19507	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19547	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19621	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18671	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	WACO	1	18.0	-0.00135	-0.18551	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.186	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18633	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 3	1	31.0	-0.18686	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18807	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19538	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19578	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19652	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19652	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18702	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	WACO	1	18.0	-0.00135	-0.18582	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.18631	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18664	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18838	5
WERE	HUTCHINSON ENERGY CENTER UNIT 4	1	149.1	-0.18717	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18838	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19525	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19565	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18689	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	WACO	1	18.0	-0.00135	-0.18569	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.18618	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18651	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 1	1	52.0	-0.18704	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19525	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19565	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18689	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	WACO	1	18.0	-0.00135	-0.18569	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.18618	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18651	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 2	1	50.0	-0.18704	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19525	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19565	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18689	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	WACO	1	18.0	-0.00135	-0.18569	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.18618	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18651	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TURBINE 3	1	52.0	-0.18704	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.19525	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.19565	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.19639	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.18689	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	WACO	1	18.0	-0.00135	-0.18569	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.18618	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.18651	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.18825	5
WERE	HUTCHINSON ENERGY CENTER GAS TRUBINE 4	1	78.0	-0.18704	WERE	CITY OF ERIE	1	20.0	0.00121	-0.18825	5
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	JEFFREY ENERGY CENTER UNIT 1	1	470.0	0.01351	-0.11314	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	JEFFREY ENERGY CENTER UNIT 2	1	470.0	0.01419	-0.11382	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	JEFFREY ENERGY CENTER UNIT 3	1	470.0	0.01419	-0.11382	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	LAWRENCE ENERGY CENTER UNIT 4	1	60.0	0.00821	-0.10784	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	LAWRENCE ENERGY CENTER UNIT 5	1	225.8	0.00861	-0.10824	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	TECUMSEH ENERGY CENTER UNIT 7	1	40.0	0.00935	-0.10898	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	TECUMSEH ENERGY CENTER UNIT 8	1	48.0	0.00935	-0.10898	8
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	EVANS ENERGY CENTER UNIT 2	1	110.0	-0.00015	-0.09948	9
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	WACO	1	18.0	-0.00135	-0.09828	9
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	CITY OF WELLINGTON	1	14.3	-0.00086	-0.09877	9
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	CITY OF WINFIELD	1	24.6	-0.00053	-0.0991	9
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	CHANUTE GENERATION SUB	1	24.5	0.00121	-0.10084	9
WERE	PAWNEE (KMEA Municipal Larned)	KL		-0.09963	WERE	CITY OF ERIE	1	20.0	0.00121	-0.10084	9

Maximum Decrement and Maximum Increment were determined from the Souce and Sink Operating Points in the study models where limiting facility was identified.
Factor = Source GSF - Sink GSF
Redispatch Amount = Relief Amount / Factor