Aggregate Facility Study
SPP-2006-AG3-AFS-10
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), 1488 MW of long-term transmission service requests have been restudied in this Aggregate Facility Study (AFS). The first phase of the AFS consisted of a revision of the impact study to reflect the withdrawal of requests for which an Aggregate Facility Study Agreement was 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 is $230 Million. Additionally an indeterminate amount 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 $682 Million. This is based on full allocation of levelized revenue requirements for upgrades to customers without consideration of base plan funding. AFS data table 3 reflects the allocation of upgrade costs to each request without potential base plan funding 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 $2 Million.

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, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are indeterminate.

The Transmission Provider will tender a Letter of Intent on April 18th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by May 3rd, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

At the conclusion of the ATSS, Service Agreements for each request for service will be tendered identifying the terms and conditions of the confirmed service.

If customers withdraw from the ATSS after posting of this AFS, the AFS will be re-performed to determine final cost allocation and Available Transmission Capability (ATC) in consideration of the remaining ATSS participants. All allocated revenue requirements for facility upgrades are assigned to the customer in the AFS data tables. Potential base plan funding allowable is contingent upon validation of designated resources meeting Attachment J, Section III B criteria.

2. <u>Introduction</u>

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. In compliance with this Order, the third open season of 2006 commenced on June 1, 2006. All requests for long-term transmission service received prior to October 1, 2006 with a signed study agreement were then included in this third Aggregate Transmission Service Study (ATSS) of 2006.

Approximately 1488 MW of long-term transmission service has been restudied in this Aggregate Facility Study (AFS) with over $230 Million in transmission upgrades being proposed. The results of the AFS are detailed in Tables 1 through 7. 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 URL 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 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, expansion plan projects, or 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 to allow start of service prior to completion of assigned network upgrades. Table 7 (if applicable) lists deferment of expansion plan projects with different upgrades with the new required in service date as a result of this AFS.

A. Financial Analysis

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. If the Customer chose Option 2, Redispatch, in the Letter of Intent sent coincident with the initial AFS, the present worth analysis of revenue requirements will be based on the deferred term with redispatch in the subsequent AFS. 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.

In the event that the engineering and construction of a previously assigned Network Upgrade may be expedited, with no additional upgrades, to accommodate a new request for Transmission Service, then the levelized present worth of only the incremental expenses though the reservation period of the new request, excluding depreciation, shall be assigned to the new request. These incremental expenses, excluding depreciation, include 1) the levelized difference in present worth of the engineering and construction expenses given the change in date to complete construction to account for additional interest expense and reduced engineering and construction expense due to inflation, 2) the levelized present worth of all expediting fees, and 3) the levelized present worth of the incremental annual carrying charges, excluding depreciation and interest, during the new reservation period taking into account both a) the reservation in which the project was originally assigned, and b) a reservation, if any, in which the project was previously expedited.

Achievable Base Plan Avoided Revenue Requirements in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.B methodology. A deferred Base Plan upgrade being defined as a different requested network upgrade needed at an earlier date that negates the need for the initial base plan upgrade within the planning horizon. A displaced Base Plan upgrade being defined as the same network upgrade being displaced by a requested upgrade needed at an earlier date. Assumption of a 40 year service life is utilized for Base Plan funded projects unless provided otherwise by the Transmission Owner. A present worth analysis of revenue requirements on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan revenue requirements due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The difference in present worth between the Base Plan and

Requested Upgrades is assigned to the transmission requests impacting this upgrade based on the displacement or deferral.

B. Third Party Facilities

For third-party facilities listed in Table 3 and Table 5, 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, third-party facilities were identified. Total engineering and construction cost estimates for required third-party facility upgrades are indeterminate. 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 for 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. An agreement between the Customer and 3rd Party Owner detailing the mitigation of the 3rd party impact must be provided to the Transmission Provider prior to tendering of a Transmission Service Agreement. These facilities also include those owned by members of the Transmission Provider who have not placed their facilities under the Transmission Provider's OATT. Upgrades on the Southwest Power Administration network requires prepayment of the upgrade cost prior to construction of the upgrade.

Third-party facilities are evaluated for only those requests whose load sinks within the SPP footprint. The Customer must arrange for study of 3rd party facilities for load that sinks outside the SPP footprint with the applicable Transmission Providers.

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 110% and 90%. The upper bound and lower bound of the emergency voltage range monitored is 110% and 90%. Transmission Owner voltage monitoring criteria is used if more restrictive. The SPS Tuco 230 kV bus voltage is monitored at 92.5% due to pre-determined system stability limitations. The WERE Wolf Creek 345 kV bus voltage is monitored at 98.5% due to transmission operating procedure.

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 115 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 1488 MW over a variety of requested service periods. The SPP MDWG 2007 Series Cases Update 2 2007/08 Winter Peak (07WP), 2008 April (08AP), 2008 Spring Peak (08G), 2008 Summer Peak (08SP), 2008 Summer Shoulder (08SH), 2008 Fall Peak (08FA), 2008/09 Winter Peak (08WP), 2009 Summer Peak (09SP), 2009/10 Winter Peak (09WP), 2012 Summer Peak (12SP), 2012/13 Winter Peak (12WP),and 2017 Summer Peak (17SP) 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. Five groups of requests were developed from the aggregate of 1488 MW in order to minimize counter flows among requested service. Each request was included in at least two of the four groups depending on the requested path. All requests were included in group five. From the twelve seasonal models, five system scenarios were developed. Scenario 1 includes SWPP OASIS transmission requests not already included in the SPP 2007 Series Cases flowing in a West to East direction with ERCOTN HVDC Tie South to North, ERCOTE HVDC Tie East to West, SPS exporting, and SPS importing from the Lamar HVDC Tie. Scenario 2 includes transmission requests not already included in the SPP 2007 Series Cases flowing in an East to West direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS exporting to the Lamar HVDC Tie. Scenario 3 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a South to North direction with ERCOTN HVDC tie South to North, ERCOTE HVDC tie East to West, SPS exporting, and

SPS exporting to the Lamar HVDC Tie. Scenario 4 includes transmission requests not already included in the SPP 2007 Series Cases flowing in a North to South direction with ERCOTN HVDC tie North to South, ERCOTE HVDC tie East to West, SPS importing, and SPS importing from the Lamar HVDC tie. Scenario 5 include all transmission not already included in the SPP 2007 Series Cases with ERCOTN North to South, ERCOTE East to West, SPS importing and SPS exporting to 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. Transmission Request Modeling

Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation transfers. The Generation to Load modeling is accomplished by developing a pre-transfer case by redispatching the existing designated network resource(s) down by the new designated network resource request amount and scaling down the applicable network load by the same amount proportionally. The post-transfer case for comparison is developed by scaling the network load back to the forecasted amount and dispatching the new designated network resource being requested. Network Integration Transmission Service requests are modeled as Generation to Load transfers in addition to Generation to Generation because the requested Network Integration Transmission Service is a request to serve network load with the new designated network resource and the impacts on transmission system are determined accordingly. If the Network Integration Transmission Service request application clearly documents that the existing designated network resource(s) is being replaced or undesignated by the new designated network resource then MW impact credits will be given to the request as is done for a redirect of existing transmission service. Point-To-Point Transmission Service requests are modeled as Generation to Generation transfers. Generation to Generation transfers are accomplished by developing a post-transfer case for comparison by dispatching the request source and redispatching the request sink.

D. 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) were applied to determine the impacted facilities. The PSS/E options chosen to conduct the analysis can be found in Appendix A.

E. 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 interim curtailment of existing confirmed service or interim 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. Curtailment of existing confirmed service is evaluated to provide only interim service. Curtailment of existing confirmed service is only evaluated at the request of the transmission customer.

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 1 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). Relief pairs from the generation shift factors for the incremental and decremental units with a greater than 3% TDF on the limiting constraint were determined from the incremental units with the lowest generation shift factors and decremental units with highest generation shift factors. If the aggregate redispatch amount for the potential relief pair was determined to be three times greater than the lower of the increment or decrement then the pair was determined not to be feasible and is not included. If transmission customer would like to see additional relief pairs beyond the relief pairs determined, the transmission customer can request SPP to provide the additional pairs. The potential relief pairs **were not** 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.

4. Study Results

A. Study Analysis Results

Tables 1 through 6 contain the steady-state analysis results of the AFS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates both with and without redispatch (based on customer selection of redispatch if available), the minimum annual allocated ATC without upgrades and season of first impact. Table 2 identifies total E & C cost allocated to each Transmission Customer, letter of credit requirements, 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 without consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades with consideration of potential base plan funding, 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, credits to be paid for previously assigned AFS facility upgrades, and any third party upgrades required. Table 4 lists all upgrade requirements with associated solutions needed to provide transmission service for the AFS, Minimum ATC per upgrade with season of impact, 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. Table 7 (if applicable) identifies deferred expansion plan projects that were replaced with requested upgrades at earlier dates.

The 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. If the additional capacity of the new or changed designated resource exceeds the 125% resource to load forecast for the year of start of service, the requested resource is not eligible for base plan funding of required network upgrades and the full cost of the upgrades is assignable to the customer. If the 5 year term and 125% resource to load criteria are met, the lesser of the planned maximum net dependable capacity (NDC) or the requested capacity is multiplied by $180,000 to determine the potential base plan funding allowable. When calculating Base Plan Funding amounts that include a wind farm, the amount used is 10% of the requested amount of service, or the NDC. The Maximum Potential Base Plan Funding Allowable may be less than the potential base plan funding allowable due to the E & C Cost allocated to the customer being lower than the potential amount allowable to the customer. The customer is responsible for any assigned upgrade costs in excess of Potential Base Plan Engineering and Construction Funding Allowable.

Regarding application of base plan funding for PTP requests, if PTP base rate exceeds upgrade revenue requirements without taking into effect the reduction of revenue requirements by potential base plan funding, then the base rate revenue pays back the Transmission Owner for upgrades and no base plan funding is applicable as the access charge must be paid as it is the higher of “OR” pricing.

However, if initially the upgrade revenue requirements exceed the PTP base rate, then potential base plan funding would be applicable. The test of the higher of “OR” pricing would then be made against the remaining assignable revenue requirements versus PTP base rate. Examples are as follows:

Example A:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 47 million with the difference of 27 million E & C assignable to the customer. If the revenue requirements for the assignable portion is 54 million and the PTP base rate is 101 million, the customer will pay the higher “OR” pricing of 101 million base rate of which 54 million revenue requirements will be paid back to the Transmission Owners for the upgrades and the remaining revenue requirements of (140-54) or 86 million will be paid by base plan funding.

Example B:

E & C allocated for upgrades is 74 million with revenue requirements of 140 million and PTP base rate of 101 million. Potential base plan funding is 10 million with the difference of 64 million E & C assignable to the customer. If the revenue requirements for this assignable portion is 128 million and the PTP base rate is 101 million the customer will pay the higher “OR” pricing of 128 million revenue requirements to be paid back to the Transmission Owners and the remaining revenue requirements of (140-128) or 12 million will be paid by base plan funding.

Example C:

E & C allocated for upgrades is 25 million with revenue requirements of 50 million and PTP base rate of 101 million. Potential base plan funding is 10 million. Base plan funding is not applicable as the higher "OR" pricing of PTP base rate of 101 million must be paid and the 50 million revenue requirements will be paid from this.

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 attestation statements 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. <u>Conclusion</u>

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.

The Transmission Provider will tender a Letter of Intent on April 18th, 2008. This will open a 15-day window for Customer response. To remain in the Aggregate Transmission Service Study (ATSS), the Transmission Provider must receive from the Transmission Customer (Customer) by May 3rd, 2008, an executed Letter of Intent. The Letter of Intent will list options the Customer must choose to clarify their commitment to remain in the ATSS. The only action required on OASIS is to WITHDRAW the request or leave the request in STUDY mode.

The Transmission Provider must receive an unconditional and irrevocable letter of credit in the amount of the total allocated Engineering and Construction costs assigned to the Customer. This letter of credit is not required for those facilities that are base plan funded. 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.

6. <u>Appendix A</u>

PSS/E CHOICES IN RUNNING LOAD FLOW PROGRAM AND ACCC

BASE CASES:
Solutions - Fixed slope decoupled Newton-Raphson solution (FDNS)
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits – Apply immediately
Solution options - X Phase shift adjustment
_ Flat start
_ Lock DC taps
_ Lock switched shunts

ACCC CASES:
Solutions – AC contingency checking (ACCC)
MW mismatch tolerance – 0.5
Contingency case rating – Rate B
Percent of rating – 100
Output code – Summary
Min flow change in overload report – 3mw
Excld cases w/ no overloads form report – YES
Exclude interfaces from report – NO
Perform voltage limit check – YES
Elements in available capacity table – 60000
Cutoff threshold for available capacity table – 99999.0
Min. contng. case Vltg chng for report – 0.02
Sorted output – None
Newton Solution:
Tap adjustment – Stepping
Area interchange control – Tie lines and loads
Var limits - Apply automatically
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 interim redispatch	Deferred Stop Date without interim redispatch	Start Date with interim redispatch	Stop Date with interim redispatch		Mimimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period
AECC	AG3-2006-001	1161209	CSWS	CSWS	70	6/1/2011	6/1/2031						0	12SP
AEPM	AG3-2006-039	1158760	CSWS	CSWS	160	7/1/2007	7/1/2012	6/1/2011	6/1/2016	6/1/2008	6/1/2013	2	0	12SP
AEPM	AG3-2006-040	1158761	CSWS	CSWS	160	11/1/2007	11/1/2012	6/1/2011	6/1/2016	6/1/2008	6/1/2013	2	0	12SP
AEPM	AG3-2006-044	1162214	CSWS	CSWS	455	6/1/2011	6/1/2031						0	12SP
AEPM	AG3-2006-094	1163062	CSWS	CSWS	550	6/1/2010	6/1/2015						0	12SP
NTEC	AG3-2006-035	1161974	CSWS	CSWS	52	6/1/2011	6/1/2031						0	12SP
OMPA	AG3-2006-028	1159596	CSWS	CSWS	41	6/1/2011	6/1/2031						0	12SP
					1488									

Note 1: Disregard Redispatch shown in Table 6 for limitations identified earlier than the start date with redispatch with the exception of limitations identified in the 2007 Summer Shoulder, and 2007 Fall Peak

Note 2: Start and Stop Dates with interim redispatch are determined based on customers choosing option to pursue redispatch to start service at Requested Start and Stop Dates or earliest date possible.

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	[1]Letter of Credit Amount Required	[2]Potential Base Plan Engineering and Construction Funding Allowable	Notes	[4]Additional Engineering and Construction Cost for 3rd Party Upgrades	[3] Total Revenue Requirements for Assigned Upgrades over term of reservation without potential base plan funding allocation	[3 5] Total Revenue Requirements for Assigned Upgrades over term of reservation WITH potential base plan funding allocation	Point-to-Point Base Rate over reservation period	[4]Total Cost of Reservation Assignable to Customer contingent upon base plan funding
AECC	AG3-2006-001	1161209	$ 28,413,544	$ -	$ 28,413,544		Indeterminate	$ 93,671,668	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-039	1158760	$ 11,891,913	$ -	$ 11,891,913			$ 20,922,438	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-040	1158761	$ 11,891,913	$ -	$ 11,891,913			$ 20,922,438	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-044	1162214	$ 102,257,966	$ -	$ 102,257,966		Indeterminate	$ 361,735,329	$ -	$ -	Schedule 9 charges
AEPM	AG3-2006-094	1163062	$ 49,966,693	$ -	$ 49,966,693		Indeterminate	$ 95,541,059	$ -	$ -	Schedule 9 charges
NTEC	AG3-2006-035	1161974	$ 10,056,395	$ 696,395	$ 9,360,000			$ 34,179,722	$ 2,366,911	$ -	$ 2,366,911
OMPA	AG3-2006-028	1159596	$ 16,416,664	$ -	$ 16,416,664		Indeterminate	$ 55,648,249	$ -	$ -	Schedule 9 charges
Totals			$ 230,895,088					$ 682,620,903	$ 2,366,911		

Note 1: Letter of Credit required for financial security for transmission owner for network upgrades is determined by allocated engineering and construction costs less engineering and construction costs for upgrades when network customer is the transmission owner less the E & C allocation of expedited projects. Letter of Credit is not required for base plan funded upgrades. The LOC listed is based on meeting OATT Attachment J requirements for base plan funding.

Note 2. 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. Not applicable if PTP base rate exceeds revenue requirements.

Note 3: Revenue Requirements (RR) are based upon deferred end dates if applicable. Deferred dates are based upon customer's choice to pursue redispatch. Achievable Base Plan Avoided RR in the case of a Base Plan upgrade being displaced or deferred by an earlier in service date for a Requested Upgrade shall be determined per Attachment J, Section VII.C methodology. Assumption of a 40 year service life is utilized for Base Plan funded projects. A present worth analysis of RR on a common year basis between the Base Plan and Requested Upgrades was performed to determine avoided Base Plan RR due to the displacement or deferral of the Base Plan upgrade by the Requested Upgrade. The incremental increase in present worth of a Requested Upgrade on a common year basis as a Base Plan upgrade is assigned to the transmission requests impacting the upgrade based on the displacement or deferral. If the displacement analysis results in lower RR due the shorter amortization period of the requested upgrade when compared to a base plan amortization period, then no direct assignment of the upgrade cost is made due to the displacement to an earlier start date.

Note 4. 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. This includes prepayments required for any SWPA upgrades. Revenue requirements for 3rd Party facilities are not calculated. Total cost to customer is based on assumption of Revenue Requirements with confirmation of base plan funding. Customer is responsible for negotiating redispatch costs if applicable. Customer is also responsible to pay credits for previously assigned upgrades that are impacted by their request. Credits can be paid from base plan funding if applicable.

Note 5: RR with base plan funding may increase or decrease even if no base plan funding is applicable to a particular request if another request that shares the upgrade is now full base plan funded resulting in a different amortization period for the upgrade and thus different RR.

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

Customer	**Study Number**
AECC	AG3-2006-001

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
AECC	1161209	CSWS	CSWS	70	6/1/2011	6/1/1931			$ 28,413,544	$ -	$ 28,413,544	$ 93,671,668
									$ 28,413,544	$ -	$ 28,413,544	$ 93,671,668

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1161209	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 149,920	$ 1,627,500	$ 632,269
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 27,959	$ 300,000	$ 117,914
	DYESS - ELM SPRINGS REC 161KV CKT 1 #1	6/1/2008	6/1/2008			$ 5,302	$ 100,000	$ 21,828
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 253,074	$ 4,800,000	$ 923,407
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 60,318	$ 500,000	$ 227,822
	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	6/1/2017	6/1/2017			$ 7,212,152	$ 9,750,000	$ 19,466,603
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 252,732	$ 2,090,000	$ 750,984
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 1,085,764	$ 9,000,000	$ 3,726,662
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	6/1/2011			$ 6,181,819	$ 57,530,000	$ 21,785,206
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011			$ 4,681,683	$ 66,000,000	$ 19,744,407
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011			$ 3,192,057	$ 45,000,000	$ 7,676,835
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 14,665	$ 100,000	$ 48,473
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 2,081	$ 19,364	$ 7,141
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 4,359	$ 35,000	$ 15,163
	SOUTH TEXARKANA REC - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 4,750,000	$ 4,750,000	$ 16,304,653
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 3,584	$ 40,000	$ 15,394
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 461,075	$ 6,500,000	$ 2,001,599
	VBI - VBI NORTH 69KV CKT 1	6/1/2017	6/1/2017			$ 75,000	$ 75,000	$ 205,306
					Total	$ 28,413,544	$ 208,216,864	$ 93,671,668

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	Earliest Service Date	Redispatch Available
1161209	412SUB - KANSAS TAP 161KV CKT 1	6/1/2012	6/1/2012		
	412SUB - KERR 161KV CKT 1	6/1/2012	6/1/2012		
	BONANZA - BONANZA TAP 161KV CKT 1	6/1/2011	6/1/2011		
	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	BULL SHOALS - BULL SHOALS 161KV CKT 1	6/1/2012	6/1/2012		
	CHAMBER SPRINGS - FARMINGTON AECC 161KV CKT 1	6/1/2017	6/1/2017		
	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	Device - Cox Cap	6/1/2013	6/1/2013		
	Device - Main Cap	6/1/2013	6/1/2013		
	Device - Mill Cap	6/1/2013	6/1/2013		
	Device - Norton Cap	6/1/2013	6/1/2013		
	EAST CENTERTON - FLINT CREEK 161 KV CKT 1	6/1/2014	6/1/2014		
	ELM SPRINGS REC - TONTITOWN 161KV CKT 1	6/1/2016	6/1/2016		
	FLINT CREEK - GENTRY REC 161KV CKT 1	6/1/2017	6/1/2017		
	KANSAS TAP - WEST SILOAM SPRINGS 161KV CKT 1	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2012	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	MUSKOGEE - PECAN CREEK 345KV CKT 1	6/1/2012	6/1/2012		
	SILOAM CITY - WEST SILOAM SPRINGS 161KV CKT 1	6/1/2012	6/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

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

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	Earliest Service Date	Redispatch Available
1161209	Device - Sunset	6/1/2013	6/1/2013		

Third Party Limitations.

Reservation	Upgrade Name	COD	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1161209	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE SOUTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
					Total	$ -	$ -

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

Customer	**Study Number**
AEPM	AG3-2006-039

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
AEPM	1158760	CSWS	CSWS	160	7/1/2007	7/1/2012	6/1/2011	6/1/2016	$ 11,891,913	$ -	$ 11,891,913	$ 20,922,438
									$ 11,891,913	$ -	$ 11,891,913	$ 20,922,438

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1158760	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 27,603	$ 1,782,291	$ 38,246
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 508	$ 32,833	$ 730
	AVOCA - EAST ROGERS 161KV CKT 1	6/1/2008	6/1/2008			$ 450,000	$ 900,000	$ 728,445
	DYESS - EAST ROGERS 161KV CKT 1	6/1/2008	6/1/2008			$ 230,950	$ 461,900	$ 373,854
	DYESS - ELM SPRINGS REC 161KV CKT 1 #1	6/1/2008	6/1/2008			$ 47,349	$ 100,000	$ 91,041
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 2,273,463	$ 4,800,000	$ 3,874,215
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 219,841	$ 500,000	$ 387,799
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011		Yes	$ 4,491,629	$ 66,000,000	$ 8,227,763
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011		Yes	$ 3,062,474	$ 45,000,000	$ 4,821,606
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 435,803	$ 4,560,000	$ 636,468
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	6/1/2009	6/1/2009			$ 62,500	$ 125,000	$ 95,682
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 94,930	$ 456,000	$ 143,035
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	6/1/2008	6/1/2010		Yes	$ 52,506	$ 200,000	$ 669,461
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011		Yes	$ 442,357	$ 6,500,000	$ 834,093
					Total	$ 11,891,913	$ 131,418,024	$ 20,922,438

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	Earliest Service Date	Redispatch Available
1158760	FULTON - HOPE 115KV CKT 1 AEPW	6/1/2012	6/1/2012		
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #1	4/1/2008	6/1/2008		Yes
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	6/1/2008	6/1/2010		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2009		Yes
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		Yes

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

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158760	HUGO POWER PLANT - VALLIANT 345 KV AEPW	6/1/2011	6/1/2011		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	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	Earliest Service Date	Redispatch Available
1158760	ALUMAX TAP - NORTHWEST TEXARKANA 138KV CKT 1	4/1/2008	6/1/2008		Yes
	BANN - NW TEXARKANA-BANN T 138KV CKT 1	4/1/2008	6/1/2008		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	4/1/2008	6/1/2009		Yes

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

Customer	Study Number
AEPM	AG3-2006-040

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
AEPM	1158761	CSWS	CSWS	160	11/1/2007	11/1/2012	6/1/2011	6/1/2016	$ 11,891,913	$ -	$ 11,891,913	$ 20,922,438
									$ 11,891,913	$ -	$ 11,891,913	$ 20,922,438

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1158761	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 27,603	$ 1,782,291	$ 38,246
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 508	$ 32,833	$ 730
	AVOCA - EAST ROGERS 161KV CKT 1	6/1/2008	6/1/2008			$ 450,000	$ 900,000	$ 728,445
	DYESS - EAST ROGERS 161KV CKT 1	6/1/2008	6/1/2008			$ 230,950	$ 461,900	$ 373,854
	DYESS - ELM SPRINGS REC 161KV CKT 1 #1	6/1/2008	6/1/2008			$ 47,349	$ 100,000	$ 91,041
	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	6/1/2010	6/1/2010			$ 2,273,463	$ 4,800,000	$ 3,874,215
	DYESS - TONTITOWN 161KV CKT 1	6/1/2010	6/1/2010			$ 219,841	$ 500,000	$ 387,799
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011		Yes	$ 4,491,629	$ 66,000,000	$ 8,227,763
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011		Yes	$ 3,062,474	$ 45,000,000	$ 4,821,606
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 435,803	$ 4,560,000	$ 636,468
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	6/1/2009	6/1/2009			$ 62,500	$ 125,000	$ 95,682
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 94,930	$ 456,000	$ 143,035
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	6/1/2008	6/1/2010		Yes	$ 52,506	$ 200,000	$ 669,461
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011		Yes	$ 442,357	$ 6,500,000	$ 834,093
					Total	$ 11,891,913	$ 131,418,024	$ 20,922,438

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	Earliest Service Date	Redispatch Available
1158761	FULTON - HOPE 115KV CKT 1 AEPW	6/1/2012	6/1/2012		
	LINWOOD - MCWILLIE STREET 138KV CKT 1 #1	4/1/2008	6/1/2008		Yes
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	6/1/2008	6/1/2010		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2009		Yes
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		Yes

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

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1158761	HUGO POWER PLANT - VALLIANT 345 KV AEPW	6/1/2011	6/1/2011		
	HUGO POWER PLANT - VALLIANT 345 KV WFEC	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	Earliest Service Date	Redispatch Available
1158761	ALUMAX TAP - NORTHWEST TEXARKANA 138KV CKT 1	4/1/2008	6/1/2008		Yes
	BANN - NW TEXARKANA-BANN T 138KV CKT 1	4/1/2008	6/1/2008		Yes
	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	4/1/2008	6/1/2009		Yes

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

Customer **Study Number**
AEPM AG3-2006-044

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
AEPM	1162214	CSWS	CSWS	455	6/1/2011	6/1/1931			$ 102,257,966	$ -	$ 102,257,966	$ 361,735,329
									$ 102,257,966	$ -	$ 102,257,966	$ 361,735,329

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1162214	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 764,916	$ 1,627,500	$ 3,225,937
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 141,602	$ 300,000	$ 597,189
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 1,540,361	$ 2,090,000	$ 4,577,129
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 6,711,928	$ 9,000,000	$ 23,037,314
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	6/1/2011			$ 42,406,792	$ 57,530,000	$ 149,444,802
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011			$ 27,293,577	$ 66,000,000	$ 115,107,218
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011			$ 18,609,257	$ 45,000,000	$ 44,754,903
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 1,701,079	$ 4,560,000	$ 5,319,374
	LINWOOD - POWELL STREET 138KV CKT 1	6/1/2012	6/1/2012			$ 266,140	$ 456,000	$ 858,617
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	6/1/2008	6/1/2010			$ 74,975	$ 200,000	$ 2,922,767
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 14,274	$ 19,364	$ 48,992
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 26,340	$ 35,000	$ 91,625
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 18,721	$ 40,000	$ 80,413
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 2,688,004	$ 6,500,000	$ 11,669,050
					Total	$ 102,257,966	$ 193,357,864	$ 361,735,329

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	Earliest Service Date	Redispatch Available
1162214	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	6/1/2017	6/1/2017		
	MUSKOGEE - PECAN CREEK 345KV CKT 1	6/1/2012	6/1/2012		
	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	6/1/2017	6/1/2017		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

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	Earliest Service Date	Redispatch Available
1162214	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	4/1/2008	6/1/2009		

Third Party Limitations.

Reservation	Upgrade Name	COD	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1162214	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE SOUTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
					Total	$ -	$ -

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

Customer	Study Number
AEPM	AG3-2006-094

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
AEPM	1163062	CSWS	CSWS	550	6/1/2010	6/1/2015			$ 49,966,693	$ -	$ 49,966,693	$ 95,541,059
									$ 49,966,693	$ -	$ 49,966,693	$ 95,541,059

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1163062	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 565,829	$ 1,627,500	$ 1,244,659
	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 1,727,085	$ 1,782,291	$ 2,821,470
	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	6/1/2010	6/1/2010			$ 31,816	$ 32,833	$ 53,841
	ARSENAL HILL - WATERWORKS 69KV CKT 1	6/1/2010	6/1/2010			$ 3,898,800	$ 3,898,800	$ 6,196,459
	ARSENAL HILL (ARSHILL1) 138/69/12.47KV TRANSFORMER CKT 1	6/1/2010	6/1/2010			$ 3,005,700	$ 3,005,700	$ 4,777,033
	ARSENAL HILL (ARSHILL2) 138/69/14.5KV TRANSFORMER CKT 2	6/1/2010	6/1/2010			$ 3,005,700	$ 3,005,700	$ 4,777,033
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 100,335	$ 300,000	$ 220,708
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011			$ 20,173,923	$ 66,000,000	$ 44,376,769
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011			$ 13,754,948	$ 45,000,000	$ 23,604,975
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 1,623,622	$ 4,560,000	$ 2,795,771
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 77,887	$ 100,000	$ 141,762
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 14,222	$ 40,000	$ 31,862
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 1,986,826	$ 6,500,000	$ 4,498,717
					Total	$ 49,966,693	$ 135,852,824	$ 95,541,059

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	Earliest Service Date	Redispatch Available
1163062	ARSENAL HILL - NORTH MARKET 69KV CKT 1	6/1/2010	6/1/2010		
	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2012	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	MUSKOGEE - PECAN CREEK 345KV CKT 1	6/1/2012	6/1/2012		
	PORT ROBSON - REDPOINT 138kV	6/1/2012	6/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		
	Wallace Lake - Port Robson - RedPoint 138 kV	6/1/2008	6/1/2010		

Third Party Limitations.

Reservation	Upgrade Name	COD	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1163062	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE SOUTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
					Total	$ -	$ -

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

Customer	**Study Number**
NTEC	AG3-2006-035

Customer	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date Without Redispatch	Deferred Stop Date Without Redispatch	Potential Base Plan Funding Allowable	Point-to-Point Base Rate	Allocated E & C Cost	Total Revenue Requirements
NTEC	1161974	CSWS	CSWS	52	6/1/2011	6/1/1931			$ 9,360,000	$ -	$ 10,056,395	$ 34,179,722
									$ 9,360,000	$ -	$ 10,056,395	$ 34,179,722

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1161974	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #2	6/1/2012	6/1/2012			$ 4,250,000	$ 4,250,000	$ 13,711,295
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 141,961	$ 2,090,000	$ 421,832
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 574,865	$ 9,000,000	$ 1,973,106
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	6/1/2011			$ 5,065,246	$ 57,530,000	$ 17,850,317
	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	6/1/2008	6/1/2010			$ 20,013	$ 200,000	$ 208,258
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 1,705	$ 19,364	$ 5,852
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 2,605	$ 35,000	$ 9,062
					Total	$ 10,056,395	$ 73,124,364	$ 34,179,722

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	Earliest Service Date	Redispatch Available
1161974	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #1	6/1/2012	6/1/2012		
	BIG SANDY - HAWKINS 69KV CKT 1	6/1/2014	6/1/2014		
	BIG SANDY - PERDUE 69KV CKT 1	6/1/2014	6/1/2014		
	CARTHAGE REC POD - ROCK HILL 138KV CKT 1	6/1/2017	6/1/2017		
	FOREST HILLS REC - MAGNOLIA TAP 69KV CKT 1	6/1/2010	6/1/2010		
	FOREST HILLS REC - QUITMAN 69KV CKT 1	6/1/2010	6/1/2010		
	GEORGIA-PACIFIC - KEATCHIE REC 138KV CKT 1	6/1/2015	6/1/2015		
	LONE STAR SOUTH - PITTSBURG 138KV CKT 1	6/1/2015	6/1/2015		
	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	6/1/2017	6/1/2017		
	MAGNOLIA TAP - WINNSBORO 69KV CKT 1	6/1/2010	6/1/2010		
	NORTH MINEOLA - QUITMAN 69KV CKT 1	6/1/2016	6/1/2016		
	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	6/1/2008	6/1/2010		
	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	6/1/2017	6/1/2017		

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	Earliest Service Date	Redispatch Available
1161974	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	4/1/2008	6/1/2009		

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

Customer	**Study Number**
OMPA	AG3-2006-028

Customer	**Reservation**	**POR**	**POD**	**Requested Amount**	**Requested Start Date**	**Requested Stop Date**	**Deferred Start Date Without Redispatch**	**Deferred Stop Date Without Redispatch**	**Potential Base Plan Funding Allowable**	**Point-to-Point Base Rate**	**Allocated E & C Cost**	**Total Revenue Requirements**
OMPA	1159596	CSWS	CSWS	41	6/1/2011	6/1/1931			$ 16,416,664	$ -	$ 16,416,664	$ 55,648,249
									$ 16,416,664	$ -	$ 16,416,664	$ 55,648,249

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
1159596	ARDMORE - ROCKY POINT 69KV CKT 1	6/1/2011	6/1/2011			$ 146,834	$ 1,627,500	$ 619,254
	DILLARD4 - HEALDTON TAP 138KV CKT 1	6/1/2011	6/1/2011			$ 30,104	$ 300,000	$ 126,960
	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	6/1/2017	6/1/2017			$ 2,537,848	$ 9,750,000	$ 6,850,005
	FULTON - HOPE 115KV CKT 1 AECC	6/1/2011	6/1/2011			$ 154,945	$ 2,090,000	$ 460,414
	HEMPSTEAD - HOPE 115KV CKT 1	6/1/2011	6/1/2011			$ 627,443	$ 9,000,000	$ 2,153,569
	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	6/1/2011	6/1/2011			$ 3,876,143	$ 57,530,000	$ 13,659,827
	Hugo - SunnySide 345kV OKGE	4/1/2008	6/1/2011			$ 4,867,559	$ 66,000,000	$ 20,528,316
	Hugo - SunnySide 345kV WFEC	4/1/2008	6/1/2011			$ 3,318,790	$ 45,000,000	$ 7,981,626
	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	12/1/2012	12/1/2012			$ 363,694	$ 4,560,000	$ 1,137,293
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	6/1/2012	6/1/2012			$ 7,448	$ 100,000	$ 24,618
	OKAY - TOLLETTE 69KV CKT 1 Displacement	6/1/2011	6/1/2011			$ 1,305	$ 19,364	$ 4,478
	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	6/1/2011	6/1/2011			$ 1,696	$ 35,000	$ 5,900
	SUNNYSIDE - UNIROYAL 138KV CKT 1	6/1/2011	6/1/2011			$ 3,474	$ 40,000	$ 14,922
	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	4/1/2008	6/1/2011			$ 479,381	$ 6,500,000	$ 2,081,069
					Total	$ 16,416,664	$ 202,551,864	$ 55,648,249

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	Earliest Service Date	Redispatch Available
1159596	BONANZA - EXCELSIOR 161KV CKT 1	6/1/2014	6/1/2014		
	BROWN - RUSSETT 138KV CKT 1 SWPA	6/1/2011	6/1/2011		
	BROWN - RUSSETT 138KV CKT 1 WFEC	6/1/2011	6/1/2011		
	CLARKSVILLE - DARDANELLE 161KV CKT 1	6/1/2012	6/1/2012		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	6/1/2011	6/1/2011		
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	6/1/2012	6/1/2012		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	6/1/2012	6/1/2011		
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	6/1/2012	6/1/2011		
	MUSKOGEE - PECAN CREEK 345KV CKT 1	6/1/2012	6/1/2012		
	RUSSETT - RUSSETT 138KV CKT 1 OKGE	12/1/2012	12/1/2012		
	RUSSETT - RUSSETT 138KV CKT 1 WFEC	12/1/2012	12/1/2012		
	SUB 124 - AURORA H.T. 161KV	6/1/2014	6/1/2014		
	SUB 438 - RIVERSIDE 161KV	6/1/2014	6/1/2014		

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

Reservation	Upgrade Name	COD	EOC	Earliest Service Date	Redispatch Available
1159596	LACYGNE - WEST GARDNER 345KV CKT 1	6/1/2006	6/1/2006		

Third Party Limitations.

Reservation	Upgrade Name	COD	EOC	Earliest Service Start Date	Redispatch Available	Allocated E & C Cost	Total E & C Cost
1159596	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 ENTR	6/1/2012	6/1/2011			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
	RUSSELLVILLE EAST - RUSSELLVILLE SOUTH 161KV CKT 1	6/1/2012	6/1/2012			$ -	$ -
					Total	$ -	$ -

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

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
AECC	FULTON - HOPE 115KV CKT 1 AECC	Upgrades to Fulton Switching Station, Reconductor the Fulton to Hope 115/138kV Line, Upgrades to McNab Substation	06/01/11	06/01/11	$ 2,090,000
AEPW	ARSENAL HILL - FORT HUMBUG 138KV CKT 1 Displacement	Rebuild 3.24 miles of 1272 AAC with 2156 ACSR. Replace 3 switches, breaker jumpers, and reset CTs @ Arsenal Hill. Replace 2 switches and jumpers @ Fort Humbug	06/01/10	06/01/10	$ 1,782,291
AEPW	ARSENAL HILL - MCWILLIE STREET 138KV CKT 1 Displacement	Replace Arsenal Hill switches and jumpers	06/01/10	06/01/10	$ 32,833
AEPW	ARSENAL HILL - WATERWORKS 69KV CKT 1	Rebuild 2.55 miles of 666 ACSR with 1272 ACSR	06/01/10	06/01/10	$ 3,898,800
AEPW	ARSENAL HILL (ARSHILL1) 138/69/12.47KV TRANSFORMER CKT 1	Replace auto & 69 kV breaker and switches	06/01/10	06/01/10	$ 3,005,700
AEPW	ARSENAL HILL (ARSHILL2) 138/69/14.5KV TRANSFORMER CKT 2	Replace auto & 69 kV breaker and switches	06/01/10	06/01/10	$ 3,005,700
AEPW	AVOCA - EAST ROGERS 161KV CKT 1	Install 3% impedance reactor set at East Rogers on 161 kV line to Avoca REC.	06/01/08	06/01/08	$ 900,000
AEPW	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #2	Reset relays @ Bann and replace switch @ Lone Star Ordinance Tap. Rebuild 4.14 miles of 397 ACSR with 795 ACSR.	06/01/12	06/01/12	$ 4,250,000
AEPW	DYESS - EAST ROGERS 161KV CKT 1	Relocate 2% impedance reactor set from Chamber Springs to East Rogers and install on 161 kV line to Dyess.	06/01/08	06/01/08	$ 461,900
AEPW	DYESS - ELM SPRINGS REC 161KV CKT 1 #1	Replace Elm Springs switch.	06/01/08	06/01/08	$ 100,000
AEPW	DYESS - ELM SPRINGS REC 161KV CKT 1 #2	Rebuild 5.17 miles of line.	06/01/10	06/01/10	$ 4,800,000
AEPW	DYESS - TONTITOWN 161KV CKT 1	Replace Dyess Breaker, Switches, & wavetrap	06/01/10	06/01/10	$ 500,000
AEPW	HEMPSTEAD - HOPE 115KV CKT 1	Reconductor from Hempstead to Hope 666 ACSR with 1590 ACSR, replace jumpers, circuit switcher, one span of conductor at Hope	06/01/11	06/01/11	$ 9,000,000
AEPW	HEMPSTEAD - NW TEXARKANA 345KV CKT 1	Build 33 miles of 2-795MCM ACSR from Turk NW Texarkana, Add 345kV terminal at NW Texarkana, Add 345kV terminal at Turk	06/01/11	06/01/11	$ 57,530,000
AEPW	LAWTON EASTSIDE (LES 4) 345/138/13.8KV TRANSFORMER CKT 1	Replace Auto with new 450 MVA auto	12/01/12	12/01/12	$ 4,560,000
AEPW	LINWOOD - MCWILLIE STREET 138KV CKT 1 #2	Replace Linwood Switches 10872 & 10873 and replace breaker jumpers	06/01/09	06/01/09	$ 125,000
AEPW	LINWOOD - POWELL STREET 138KV CKT 1	Replace Breaker, Switches, & Jumpers @ Linwood. Replace circuit switcher @ Powell Street	06/01/12	06/01/12	$ 456,000
AEPW	LONGWOOD (LONGWOOD) 345/138/13.2KV TRANSFORMER CKT 1	Replac four (4) switches and upgrading bus work	06/01/08	06/01/10	$ 200,000
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 # 2	Replace Jumpers @ N. Magazine	06/01/12	06/01/12	$ 100,000
AEPW	OKAY - TOLLETTE 69KV CKT 1 Displacement	Replace switches	06/01/11	06/01/11	$ 19,364
AEPW	SE TEXARKANA - TEXARKANA PLANT 69KV CKT 1	Change out the 500 CU jumpers @ Texarkana Plant	06/01/11	06/01/11	$ 35,000
AEPW	SOUTH TEXARKANA REC - TEXARKANA PLANT 69KV CKT 1	Rebuild 5.92 miles of 266 ACSR with 795 ACSR. Replace switches, jumpers, and reset CTs & relays @ Texarkana Plant	06/01/11	06/01/11	$ 4,750,000
OKGE	ARDMORE - ROCKY POINT 69KV CKT 1	Replace 4.65 miles of line w/477AS33	06/01/11	06/01/11	$ 1,627,500
OKGE	DILLARD4 - HEALDTON TAP 138KV CKT 1	Replace Differential Relaying	06/01/11	06/01/11	$ 300,000
OKGE	FT SMITH 500 (FTSMITH3) 500/161/13.8KV TRANSFORMER CKT 3	Convert Ft. Smith 161kv to 1-1/2 breaker design and install 3rd 500-161kV transformer bank.	06/01/17	06/01/17	$ 9,750,000
OKGE	Hugo - SunnySide 345kV OKGE	Add 345 line from Hugo to SunnySide, Install breaker, switches, and relays	04/01/08	06/01/11	$ 66,000,000
OKGE	SUNNYSIDE - UNIROYAL 138KV CKT 1	Replace wavetrap 800A at Uniroyal	06/01/11	06/01/11	$ 40,000
OKGE	SUNNYSIDE (SUNNYSD3) 345/138/13.8KV TRANSFORMER CKT 1	Add 2nd 345/138KV Auto	04/01/08	06/01/11	$ 6,500,000
OKGE	VBI - VBI NORTH 69KV CKT 1	Upgrade CT	06/01/17	06/01/17	$ 75,000
WFEC	Hugo - SunnySide 345kV WFEC	Add 345 line from Hugo to SunnySide	04/01/08	06/01/11	$ 45,000,000

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	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	ALUMAX TAP - NORTHWEST TEXARKANA 138KV CKT 1	Rebuild 1.68 miles of 1024 ACAR with 2156 ACSR, Replace wavetrap & jumpers with 2156 ACSR. Replace Switch 2285 @ Alumax Tap.	04/01/08	06/01/08
AEPW	BANN - NW TEXARKANA-BANN T 138KV CKT 1	Rebuild 3.4 miles of 2-477 ACSR with 2156 ACSR. Reset Bann Relay	04/01/08	06/01/08
AEPW	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 2	Replace Auto, two 138 kV breakers and five 138 kV switches. Reset relays and CTs	04/01/08	06/01/09
SPRM	Device - Sunset	30 Mvar Capacitor Bank at Sunset	06/01/13	06/01/13

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

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	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	ARSENAL HILL - NORTH MARKET 69KV CKT 1	Rebuild 2.3 miles of 666 ACSR with 1272 ACSR	06/01/10	06/01/10
AEPW	BANN - LONESTAR ORDINANCE TAP 69KV CKT 1 #1	Relay at Bann New limits will be 65/72 MVA summer (line conductor/Lone Star switch) and 72/72 MVA winter (Lone Star Switch)	06/01/12	06/01/12
AEPW	BIG SANDY - HAWKINS 69KV CKT 1	Rebuild 5.5 miles of 477 ACSR with 1272 ACSR.	06/01/14	06/01/14
AEPW	BIG SANDY - PERDUE 69KV CKT 1	Rebuild 5.4 miles of 477 ACSR with 1272 ACSR.	06/01/14	06/01/14
AEPW	BONANZA - BONANZA TAP 161KV CKT 1	Rebuild 0.06 miles of 397 ACSR with 1272 ACSR & reset relay @ Bonanza or Bonanza T-Excelsior-Midland-N. Huntington 161 kV loop	06/01/11	06/01/11
AEPW	BONANZA - EXCELSIOR 161KV CKT 1	New 161 kV from Bonanza to Excelsior (includes Bonanza station)	06/01/14	06/01/14
AEPW	CARTHAGE REC POD - ROCK HILL 138KV CKT 1	Replace transformer differential relay and reset cts	06/01/17	06/01/17
AEPW	CHAMBER SPRINGS - FARMINGTON AECC 161KV CKT 1	Rebuild / reconductor 10.24 miles of line with 2156 ACSR.	06/01/17	06/01/17
AEPW	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 AEPW	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	06/01/11	06/01/11
AEPW	EAST CENTERTON - FLINT CREEK 161 KV CKT 1	Reconductor Flint Creek-East Centerton 161 kV with 2156 conductor	06/01/14	06/01/14
AEPW	ELM SPRINGS REC - TONTITOWN 161KV CKT 1	Replace Wavetrap and switch jumpers	06/01/16	06/01/16
AEPW	FLINT CREEK - GENTRY REC 161KV CKT 1	Rebuild 1.09 miles of 2-397.5 ACSR with 2156 ACSR. Replace Flint Creek wavetrap & jumpers	06/01/17	06/01/17
AEPW	FOREST HILLS REC - MAGNOLIA TAP 69KV CKT 1	Rebuild 7.91 miles of 477 ACSR with 1272 ACSR & replace switch 9116	06/01/10	06/01/10
AEPW	FOREST HILLS REC - QUITMAN 69KV CKT 1	Replace Quitman bus, switches & jumpers. Change CT & relay settings @ Quitman	06/01/10	06/01/10
AEPW	FULTON - HOPE 115KV CKT 1 AEPW	Replace strain bus in Hope Substation	06/01/12	06/01/12
AEPW	GEORGIA-PACIFIC - KEATCHIE REC 138KV CKT 1	Rebuild 12.63 miles of 795 ACSR with 1272 ACSR	06/01/15	06/01/15
AEPW	LINWOOD - MCWILLIE STREET 138KV CKT 1 #1	Rebuild 2.09 miles of 666 ACSR with 1272 ACSR	04/01/08	06/01/08
AEPW	LONE STAR SOUTH - PITTSBURG 138KV CKT 1	Replace wavetraps at both ends. Reset CTs @ Lone Star South. Replace switches & reset relays @ Pittsburg	06/01/15	06/01/15
AEPW	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	Reconductor 1.8 miles of 666 ACSR with 1272 ACSR	06/01/17	06/01/17
AEPW	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 AEPW	Rebuild 7.43 miles of 250 CWC with 795 ACSR	06/01/12	06/01/11
AEPW	MAGNOLIA TAP - WINNSBORO 69KV CKT 1	Replace switch # 9114 @. Replace switches @ Winnsboro. Reset Cts and relay settings at Winnsboro.	06/01/10	06/01/10
AEPW	NORTH MINEOLA - QUITMAN 69KV CKT 1	Mineola to Quipman 69 kV up grade switches and sub conductor N Mineola and Quipman subs	06/01/16	06/01/16
AEPW	PORT ROBSON - REDPOINT 138kV	New 138 kV line from Port Robson - Red Point via McDade & Haughton. Convert McDade & Haughton to 138 kV.	06/01/12	06/01/12
AEPW	SOUTHWEST SHREVEPORT - SOUTHWEST SHREVEPORT TAP 138KV CKT 1	Rebuild 2.29 miles of 2-397.5 ACSR with 2-795 ACSR. Double Circuit the line and add terminal @ SW Shreveport to eliminate three terminal line.	06/01/08	06/01/10
AEPW	SOUTHWEST SHREVEPORT - WESTERN ELECTRIC T 138KV CKT 1	Rebuild 2.9 miles of 2-795 ACSR with 2156 ACSR. Replace switch 1647 @ Western Electric "T". Replace switch 10237 & reset relays @ SW Shreveport.	06/01/17	06/01/17
AEPW	SOUTHWEST SHREVEPORT (SW SHV 1) 345/138/13.8KV TRANSFORMER CKT 1	Using IEEE Guide for Loading of Mineral-Oil Immersed Power Transformers (C57.91-2000) Re-rate the autos. Replace .two 138 kV breakers and five 138 kV switches. Reset relays and CTs	04/01/08	06/01/09
AEPW	Wallace Lake - Port Robson - RedPoint 138 kV	Convert Red Point - Haughton-McDade to 138 kV, 1590 ACSR (includes McDade station conversion)	6/1/2008	6/1/2010
EMDE	SUB 124 - AURORA H.T. 161KV	Install 3 - stages of 22 MVAR each for total of 66 MVAR capacitor bank at Aurora Sub #124 bus# 547537	06/01/14	06/01/14
EMDE	SUB 438 - RIVERSIDE 161KV	Install 3 - stages of 22 MVAR each for a total of 66 MVAR capacitor bank at Riverside Sub #438 547497	06/01/14	06/01/14
GRDA	412SUB - KANSAS TAP 161KV CKT 1	Reconductor 9.7 miles with 1590MCM ACSR.	06/01/12	06/01/12
GRDA	412SUB - KERR 161KV CKT 1	Reconductor 8/10ths of mile out of Kerr Dam	06/01/12	06/01/12
GRDA	KANSAS TAP - WEST SILOAM SPRINGS 161KV CKT 1	Rebuild line to 1590 ACSR	06/01/12	06/01/12
GRDA	SILOAM CITY - WEST SILOAM SPRINGS 161KV CKT 1	Rebuild line to 1590 ACSR	06/01/12	06/01/12
OKGE	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 OKGE	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	06/01/12	06/01/11
OKGE	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 OKGE	Rebuild 7.43 miles of 250 CWC with 795 ACSR	06/01/12	06/01/11
OKGE	MUSKOGEE - PECAN CREEK 345KV CKT 1	Increase CT ration at Pecan Creek from 800-5 to 2000-5 to allow a 1500 amp rating of line section.	06/01/12	06/01/12
OKGE	RUSSETT - RUSSETT 138KV CKT 1 OKGE	Replace trap and increase CTR. Pending verification of relays.	12/01/12	12/01/12
SPRM	Device - Cox Cap	Install 30 Mvar capacitor at Cox 69 kV bus	06/01/13	06/01/13
SPRM	Device - Main Cap	Install 30 Mvar capacitor at Main 161 kv bus	06/01/13	06/01/13
SPRM	Device - Mill Cap	Install 30 Mvar capacitor at Mill 161 kV bus	06/01/13	06/01/13
SPRM	Device - Norton Cap	Install 30 Mvar capacitor at Norton 161 kV bus	06/01/13	06/01/13
SWPA	BROWN - RUSSETT 138KV CKT 1 SWPA	Upgrade Terminal Equipment at Brown- Switches/Wavetraps	06/01/11	06/01/11
SWPA	BULL SHOALS - BULL SHOALS 161KV CKT 1	Replace buswork in Bull Shoals switchyard.	06/01/12	06/01/12
SWPA	CLARKSVILLE - DARDANELLE 161KV CKT 1	Reconductor Clarksville-Dardanelle line	06/01/12	06/01/12
SWPA	DARDANELLE - RUSSELLVILLE SOUTH 161KV CKT 1 SWPA	Replace wave trap, disconnect switches, current transformers, and breaker. Bus will limit rating to 1340 amps.	06/01/12	06/01/12
WFEC	BROWN - RUSSETT 138KV CKT 1 WFEC		06/01/11	06/01/11
WFEC	RUSSETT - RUSSETT 138KV CKT 1 WFEC	Upgrade Terminal Equip CTs at Russett	12/01/12	12/01/12

Previously Assigned Aggregate Study Upgrades requiring credits to Previous Aggregate Study Customers.

Transmission Owner	Upgrade	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	HUGO POWER PLANT - VALLIANT 345 KV AEPW	Vallient 345 KV line terminal	06/01/11	06/01/11
KACP	LACYGNE - WEST GARDNER 345KV CKT 1	KCPL Sponsored Project to Reconductor Line to be In-Service by 6/1/2006	06/01/06	06/01/06
OKGE	ARCADIA - REDBUD 345 KV CKT 1	Sponsored Project to Uprate Terninal Equipment	06/01/06	06/01/06
OKGE	ARCADIA - REDBUD 345 KV CKT 2	Sponsored Project to Uprate Terninal Equipment	06/01/06	06/01/06
WFEC	HUGO POWER PLANT - VALLIANT 345 KV WFEC	New 345/138 kv Auto, and 19 miles 345 KV	05/01/10	05/01/10

Table 5 - Third Party Facility Constraints

Transmission Owner	UpgradeName	Solution	Earliest Data Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)	Estimated Engineering & Construction Cost
ENTR	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	Indeterminate	06/01/12	06/01/12	$ -
ENTR	RUSSELLVILLE EAST - RUSSELLVILLE NORTH 161KV CKT 1	Indeterminate	06/01/12	06/01/12	$ -
ENTR	RUSSELLVILLE EAST - RUSSELLVILLE SOUTH 161KV CKT 1	Indeterminate	06/01/12	06/01/12	$ -
ENTR	DANVILLE (APL) - MAGAZINE REC 161KV CKT 1 ENTR	Rebuild 17.96 miles of 250 Copperweld with 1272 ACSR.	06/01/12	06/01/11	$ -
ENTR	MAGAZINE REC - NORTH MAGAZINE 161KV CKT 1 ENTR	Rebuild 7.43 miles of 250 CWC with 795 ACSR	06/01/12	06/01/11	$ -