Southwest Power Pool

Final Aggregate Facility Study SPP-2005-AG1-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), 399 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 facility upgrade Engineering and Construction (E &C) cost determined by the AFS restudy is $20,014,000. The total upgrade levelized revenue requirement for all transmission requests is $47,067,115. 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. Total upgrade levelized revenue requirements for all transmission requests after consideration of potential base plan funding is $6,563,333.

Third-party facilities must be upgraded when it is determined they are constrained in order to accommodate the requested Transmission Service.

The Transmission Provider will tender Letter 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 Agreements for new designated network resource requests for those Transmission Customers that are not currently taking SPP NITS.

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 final approval of designated resources meeting Attachment J, Section III B criteria.

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 hyperlink 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 first open season commenced on February 1, 2005. All requests for long-term transmission service received prior to June 1, 2005 with a signed study agreement were then included in the first Aggregate Transmission Service Study (ATSS).

Approximately 399 MW of long-term transmission service has been restudied in this final Aggregate Facility Study (AFS) with over $20 Million in transmission upgrades is being proposed. The results of the final AFS are detailed in Tables 1 through 4. 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 hyperlink 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 the information necessary to verify that the requested new or changed Designated Resource meets specific criteria.

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 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. Customers paying the above charges may receive credits in accordance with Section VI.B.

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 2. This table also includes constrained facilities in the current planning horizon that limit the rollover rights of the Transmission Customer as well as any redispatch required to allow start of service prior to completion of assigned network upgrades.

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. 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.

B. Third-Party Facilities

For third-party facilities listed in Table 4 and Table 2, the Transmission Customer is responsible for funding the necessary upgrades of these facilities per Section 21.1 of the Transmission Provider's OATT. 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. 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 thirteen seasonal models to study the aggregate transfers of 399 MW over a variety of requested service periods. The SPP MDWG 2005 Series Cases Update 3 2005 Fall Peak (05FA), 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 399 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 1^{st}-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.

C. 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.

SPP evaluated curtailment of confirmed service or redispatch of units based on specific Transmission Customer requests. In order to expedite the evaluation of curtailment or redispatch, the Transmission Customer must provide the confirmed service for curtailment and the specific inter-control area generation units for redispatch. SPP then determined the feasibility of the provided options in order to provide service prior to completion of any assigned network upgrades. Redispatch is not evaluated as a viable long term solution in lieu of network upgrades. Redispatch was evaluated to provide only interim service during the time frame prior to completion of any assigned network upgrades.

Using the specific generation units provided by the Transmission Customer, SPP determined feasible relief pairs to relieve the incremental MW impact on limiting facilities identified. 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 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 top relief pairs were evaluated using MUST's First Contingency Incremental Transfer Capability (FCITC) function to determine impacts on limiting facilities in the SPP and 1st-Tier systems. If limiting facilities were identified as being impacted by the relief pair, the relief pair was not considered a feasible relief pair.

4. Study Results

A. Study Analysis Results

Tables 1 through 3 contain the steady-state analysis results of the ASIS. Table 1 identifies the participating long-term transmission service requests included in the AFS. This table lists deferred start and stop dates, the minimum annual allocated ATC without upgrades and season of first impact, total E & C cost allocated to each Transmission Customer, potential base plan E & C funding (lower of allocated E & C or safe harbor criteria) , total revenue requirements for assigned upgrades in consideration of potential base plan funding, point-to-point base rate charge, total revenue requirements for assigned upgrades over the term of the reservation, and final total cost allocation to the Transmission Customer. Table 2 provides additional details for each request including all facility upgrades required, third party upgrades required, allocated E & C costs, any required redispatch until upgrades can be completed to prevent deferral of start of service, and revenue requirements for each upgrade. Table 2 also lists facilities requiring no upgrades for various reasons or facilities limiting rollover rights. This includes the season in the planning horizon where rollover rights are limited. Table 3 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 4 lists identified Third-Party constrained facilities.

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 and upon SPP Board of Directors approval. If all conditions are met, the higher of the requested designated resource capacity (MW), or the designated resource maximum capacity not exceeding the 125% resource to load determination is multiplied by the safe harbor criteria, $180,000/MW to determine potential base plan funding allowable. For example, a 50MW request that meets all other conditions and increases the resource to load determination from 115% to 120% would result in $9,000,000 of potential base plan funding allowable.

The 125% resource to load determination is based on the total of all of the Transmission Customer's requested designated resources capacity per year of start of requested service or deferred start date, whichever is the latest.

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. Facility upgrade revenue requirements will be re-calculated after base plan funding verification.

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 facility upgrades are required as noted in Table 2.

The Transmission Provider will tender Letter 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 Agreements for new designated network resource requests for those Transmission Customers that are not currently taking SPP NITS.

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.

If the Transmission Customer desires to take transmission service prior to the deferred start date required for facility upgrade completion, short term service can be utilized pursuant to the SPP OATT.

Curtailment or redispatch options evaluated by SPP for long-term service must be provided by the Transmission Customer in advance. SPP will determine if the curtailment or redispatch is a feasible solution in order to provide service prior to completion of any assigned network upgrades.The Transmission Customer shall provide proof to SPP of any curtailment or redispatch agreement between the Transmission Customer, a Transmission Owner or any other Generators for curtailment or redispatch to provide service prior to completion of any assigned network upgrades. The curtailment or redispatch requirements would be called upon prior to implementing NERC TLR Level 5a.

Appendix

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 the Aggregate System Impact Study

Customer	Study Number	Reservation	POR	POD	Requested Amount	Requested Start Date	Requested Stop Date	Deferred Start Date	Deferred Stop Date	Minimum Allocated ATC (MW) within reservation period	Season of Minimum Allocated ATC within reservation period	Total Engineering and Construction Cost Allocated to Customer	Potential Base Plan Engineering and Construction Funding Allowable per Request	Total Revenue Requirements for Assigned Upgrades over term of Reservation with Potential Base Plan Funding Allocation.	Total Revenue Requirements for Assigned Upgrades over Term of Reservation without Potential Base Plan Funding.	Point-to-Point Base Rate	Total Cost of Reservation Assignable to Customer
APM	AG1-2005-001	851299	AECI	OKGE	13	5/1/2005	5/1/2006	11/1/2005	11/1/2006	13	N/A	$ -	$ -	N/A	$ -	$ -	Schedule 9 rates
CSWM	AG1-2005-069	852362	CSWS	CSWS	100	1/1/2006	1/1/2008			0	05WP	$ 30,743	$ -	N/A	$ 44,664	$ -	$44,664 plus possible 3rd party limitations
CSWM	AG1-2005-069	852367	CSWS	CSWS	100	1/1/2006	1/1/2008	6/1/2009	6/1/2011	0	06SP	$ 1,794,257	$ -	N/A	$ 2,591,320	$ -	$ 2,591,320
CSWM	AG1-2005-072	874597	CSWS	CSWS	41	12/1/2005	12/1/2015			0	10SP	$ 5,040,000	$ 738,000	$ 3,927,349	$ 4,601,709	$ -	$ 4,601,709
KPP	AG1-2005-078	896877	GRDA	WR	18	5/1/2006	5/1/2026	6/1/2009	6/1/2026	0	06SP	$ 7,434,639	$ 7,434,639	$0	$ 21,594,151	$ -	$ 21,594,151
OMPA	AG1-2005-009	843135	WR	WR	114	4/1/2005	4/1/2010	10/1/2006	10/1/2011	0	10SP	$ 5,714,361	$ 5,714,361	$0	$ 18,235,271	$ -	$ 18,235,271
SPA	AG1-2005-077	896846	WFEC	SPA	13	4/1/2006	6/1/2020			0	15SP	$ -	$ -	N/A	$ -	$ 1,878,712	$ 1,878,712
											Totals	$ 20,014,000	$ 13,887,000	$ 3,927,349	$ 47,067,115		

Table 2 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer **Study Number**
APM **AG1-2005-001**

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
APM	851299	AECI	OKGE	13	5/1/2005	5/1/2006	11/1/2005	11/1/2006	$ -	$ -	$ -	$ -
										Total	**$ -**	**$ -**

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
851299	N/A					
			Total	**$ -**	**$ -**	**$ -**

Customer **Study Number**
KPP **AG1-2005-078**

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
KPP	896877	GRDA	WR	18	5/1/2006	5/1/2026	6/1/2009	6/1/2026	$ 7,434,639	$ -	$ 7,434,639	$ 21,594,151
										Total	**$ 7,434,639**	**$ 21,594,151**

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements	Code
896877	412SUB - KANSAS TAP 161KV CKT 1	6/1/2015	6/1/2015	$ 1,488,000	$ 1,488,000	$ 4,930,818	S
	412SUB - KERR 161KV CKT 1	6/1/2015	6/1/2015	$ 1,918,000	$ 1,918,000	$ 6,355,718	S
	BELL - PECK 69KV CKT 1	6/1/2007	6/1/2007	$ 457,260	$ 2,000,000	$ 813,317	S
	CRESWELL - OAK 69KV CKT 1	6/1/2011	6/1/2011	$ 143,000	$ 143,000	$ 742,398	S
	GILL ENERGY CENTER WEST - PECK 69KV	6/1/2006	6/1/2007	$ 1,096,050	$ 3,000,000	$ 2,162,576	S
	MIDIAN (MIDIAN1X) 138/69/13.2KV TRANSFORMER CKT 1	6/1/2006	6/1/2007	$ 213,945	$ 1,500,000	$ 422,127	S
	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	6/1/2015	6/1/2015	$ 1,500,000	$ 1,500,000	$ 4,947,085	S
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2006	6/1/2007	$ 618,384	$ 1,600,000	$ 1,220,111	S
			Total	**$ 7,434,639**	**$ 13,149,000**	**$ 21,594,151**	

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
896877	AEPW PLANNED UPGRADE FOR NW ARKANSAS	4/1/2006	6/1/2009
	CRESWELL - PARIS 69KV CKT 1	6/1/2006	6/1/2007

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
896877	BUTLER 138/69KV TRANSFORMER CKT 1	6/1/2010	6/1/2010

Customer **Study Number**
OMPA **AG1-2005-009**

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
OMPA	843135	WR	WR	114	4/1/2005	4/1/2010	10/1/2006	10/1/2011	$ 5,714,361	$ -	$ 5,714,361	$ 18,235,271
										Total	**$ 5,714,361**	**$ 18,235,271**

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
843135	BELL - PECK 69KV CKT 1	6/1/2007	6/1/2007	$ 1,542,740	$ 2,000,000	$ 6,223,636
	GILL ENERGY CENTER WEST - PECK 69KV	6/1/2006	6/1/2007	$ 1,903,950	$ 3,000,000	$ 5,482,174
	MIDIAN (MIDIAN1X) 138/69/13.2KV TRANSFORMER CKT 1	6/1/2006	6/1/2007	$ 1,286,055	$ 1,500,000	$ 3,703,026
	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	6/1/2006	6/1/2007	$ 981,616	$ 1,600,000	$ 2,826,434
			Total	**$ 5,714,361**	**$ 8,100,000**	**$ 18,235,271**

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
843135	BUTLER 138/69KV TRANSFORMER CKT 1	6/1/2010	6/1/2010

Table 2 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer **Study Number**
CSWM **AG1-2005-069**

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
CSWM	852362	CSWS	CSWS	100	1/1/2006	1/1/2008			$ -	$ -	$ 30,743	$ 44,664
CSWM	852367	CSWS	CSWS	100	1/1/2006	1/1/2008	6/1/2009	6/1/2011	$ -	$ -	$ 1,794,257	$ 2,591,320
										Total	**$ 1,825,000**	**$ 2,635,984**

*Reservation 852362 studied as a Designated Network Resource for PSO network load in the AEPW control area.
*Reservation 852367 studied as a Designated Network Resource for SWEPCO network load in the AEPW control area.

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
852362	NORTHWEST HENDERSON - OAK HILL #1 138KV CKT 1	6/1/2007	6/1/2007	$ 30,743	$ 75,000	$ 44,664
			Total	**$ 30,743**	**$ 75,000**	**$ 44,664**
852367	NORTHWEST HENDERSON - OAK HILL #1 138KV CKT 1	6/1/2007	6/1/2007	$ 44,257	$ 75,000	$ 73,303
	WHITNEY 138/69/12.5KV TRANSFORMER	6/1/2008	6/1/2008	$ 1,750,000	$ 1,750,000	$ 2,518,017
			Total	**$ 1,794,257**	**$ 1,825,000**	**$ 2,591,320**

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
852362	AEP Tulsa Project	6/1/2006	6/1/2007
	KNOX LEE - OAK HILL #2 138KV	6/1/2006	6/1/2007
852367	AEPW PLANNED UPGRADE FOR NW ARKANSAS	4/1/2006	6/1/2009
	KNOX LEE - OAK HILL #2 138KV	6/1/2006	6/1/2007

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
852367	ALUMAX TAP - BANN 138KV CKT 1	6/1/2010	6/1/2010
	ALUMAX TAP - NORTHWEST TEXARKANA 138KV CKT 1	6/1/2006	4/1/2008
	LONGWOOD - OAK PAN-HARR REC 138KV CKT 1	6/1/2010	6/1/2010

Redispatch Required for reservation 852362 to prevent deferral service

Upgrade: AEPW Tulsa Project
Limiting Facility: SAND SPRINGS - WEST EDISON TAP 138KV CKT 1
Direction: To->From
Line Outage: SHEFFIELD - WEKIWA 138KV CKT 1
Date Redispatch Needed: 6/1/06-10/1/06
Relief Amount: 2.8 MW

Source Control Area	Source	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
AEPW	TULSA POWER STATION # 1	145	-0.135	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.162	17
AEPW	TULSA POWER STATION # 4	146	-0.135	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.162	17
AEPW	TULSA POWER STATION # 1	145	-0.135	AEPW	NORTHEASTERN STATION #2	298	0.027	-0.162	17
AEPW	TULSA POWER STATION # 4	146	-0.135	AEPW	NORTHEASTERN STATION #2	298	0.027	-0.162	17
AEPW	TULSA POWER STATION # 1	145	-0.135	AEPW	NORTHEASTERN STATION # 1-1A	51.5	0.027	-0.162	17
AEPW	TULSA POWER STATION # 4	146	-0.135	AEPW	NORTHEASTERN STATION # 1-1A	51.5	0.027	-0.162	17
AEPW	TULSA POWER STATION # 1	145	-0.135	AEPW	NORTHEASTERN STATION # 1-1B	51.5	0.027	-0.162	17
AEPW	TULSA POWER STATION # 4	146	-0.135	AEPW	NORTHEASTERN STATION # 1-1B	51.5	0.027	-0.162	17
AEPW	TULSA POWER STATION # 1	145	-0.135	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.161	17
AEPW	TULSA POWER STATION # 4	146	-0.135	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.161	17
AEPW	RIVERSIDE STATION #1	247	-0.078	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.105	27
AEPW	RIVERSIDE STATION #2	233	-0.078	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.105	27
AEPW	RIVERSIDE STATION #1	247	-0.078	AEPW	NORTHEASTERN STATION #2	298	0.027	-0.105	27
AEPW	RIVERSIDE STATION #2	233	-0.078	AEPW	NORTHEASTERN STATION #2	298	0.027	-0.105	27
AEPW	RIVERSIDE STATION #1	247	-0.078	AEPW	NORTHEASTERN STATION # 1-1A	51.5	0.027	-0.105	27
AEPW	RIVERSIDE STATION #2	233	-0.078	AEPW	NORTHEASTERN STATION # 1-1A	51.5	0.027	-0.105	27
AEPW	RIVERSIDE STATION #1	247	-0.078	AEPW	NORTHEASTERN STATION # 1-1B	51.5	0.027	-0.105	27
AEPW	RIVERSIDE STATION #2	233	-0.078	AEPW	NORTHEASTERN STATION # 1-1B	51.5	0.027	-0.105	27
AEPW	RIVERSIDE STATION #1	247	-0.078	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.104	27
AEPW	RIVERSIDE STATION #2	233	-0.078	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.104	27

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 2 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Upgrade: AEPW Tulsa Project
Limiting Facility: SAND SPRINGS - WEST EDISON TAP 138KV CKT 1
Direction: To->From
Line Outage: SHEFFIELD - WEKIWA 138KV CKT 1
Date Redispatch Needed: 12/1/06-4/1/07
Relief Amount: 0.6 MW

Source Control Area	Source	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.162	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.162	4
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION #2	205	0.027	-0.162	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION #2	205	0.027	-0.162	4
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION # 1-1A	46.5	0.027	-0.162	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION # 1-1A	46.5	0.027	-0.162	4
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION # 1-1B	45.5	0.027	-0.162	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION # 1-1B	45.5	0.027	-0.162	4
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.161	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.161	4
AEPW	TULSA POWER STATION # 1	-0.13462	160.000	AEPW	NORTHEASTERN STATION #4	315	0.026	-0.161	4
AEPW	TULSA POWER STATION # 4	-0.13462	160.000	AEPW	NORTHEASTERN STATION #4	315	0.026	-0.161	4
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.105	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION #1	67	0.027	-0.105	6
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION #2	205	0.027	-0.105	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION #2	205	0.027	-0.105	6
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION # 1-1A	46.5	0.027	-0.105	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION # 1-1A	46.5	0.027	-0.105	6
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION # 1-1B	45.5	0.027	-0.105	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION # 1-1B	45.5	0.027	-0.105	6
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.104	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION #3	320	0.026	-0.104	6
AEPW	RIVERSIDE STATION #1	-0.07778	219.000	AEPW	NORTHEASTERN STATION #4	315	0.026	-0.104	6
AEPW	RIVERSIDE STATION #2	-0.07778	455.000	AEPW	NORTHEASTERN STATION #4	315	0.026	-0.104	6

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

Upgrade: KNOX LEE - OAK HILL #2 138KV CKT 1
Limiting Facility: KNOX LEE - OAK HILL #2 138KV CKT 1
Direction: From->To
Line Outage: KNOX LEE - MONROE CORNERS REC 138KV CKT 1
Date Redispatch Needed: 6/1/06-10/1/06
Relief Amount: 3.5 MW

Source Control Area	Source	Maximum Increment (MW)	GSF	Sink Control Area	Sink	Maximum Decrement (MW)	GSF	Factor	Redispatch Amount (MW)
AEPW	WILKES #1	33	0.004	AEPW	KNOXLEE #4	34	0.027	-0.059	60
AEPW	WILKES #2	17	0.004	AEPW	KNOXLEE #4	34	0.027	-0.059	60
AEPW	WILKES #1	33	0.004	AEPW	KNOXLEE #5	278	0.027	-0.059	60
AEPW	WILKES #2	17	0.004	AEPW	KNOXLEE #5	278	0.027	-0.059	60
AEPW	WILKES #3	26	0.005	AEPW	KNOXLEE #4	34	0.027	-0.058	61
AEPW	WILKES #3	26	0.005	AEPW	KNOXLEE #5	278	0.027	-0.058	61
AEPW	ARSENAL HILL	31	0.005	AEPW	KNOXLEE #4	34	0.027	-0.057	61
AEPW	ARSENAL HILL	31	0.005	AEPW	KNOXLEE #5	278	0.027	-0.057	61
AEPW	WELSH #1	20	0.005	AEPW	KNOXLEE #4	34	0.027	-0.057	61
AEPW	WELSH #2	20	0.005	AEPW	KNOXLEE #4	34	0.027	-0.057	61
AEPW	WELSH #3	20	0.005	AEPW	KNOXLEE #4	34	0.027	-0.057	61
AEPW	WELSH #1	20	0.005	AEPW	KNOXLEE #5	278	0.027	-0.057	61
AEPW	WELSH #2	20	0.005	AEPW	KNOXLEE #5	278	0.027	-0.057	61
AEPW	WELSH #3	20	0.005	AEPW	KNOXLEE #5	278	0.027	-0.057	61
AEPW	LIEBERMAN #1	27	0.006	AEPW	KNOXLEE #4	34	0.026	-0.057	62
AEPW	LIEBERMAN #2	27	0.006	AEPW	KNOXLEE #4	34	0.026	-0.057	62
AEPW	LIEBERMAN #1	27	0.006	AEPW	KNOXLEE #5	278	0.027	-0.057	62
AEPW	LIEBERMAN #2	27	0.006	AEPW	KNOXLEE #5	278	0.027	-0.057	62

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

Redispatch Evaluated for reservation 852367 not feasible to prevent deferral service due to NW Arkansas Limitations

Table 2 - Additional Details for Each Request Including All Facility Upgrades Required and Allocated Costs for Each Upgrade

Customer **Study Number**
CSWM **AG1-2005-072**

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
CSWM	874597	CSWS	CSWS	41	12/1/2005	12/1/2015			$ 738,000	$ -	$ 5,040,000	$ 4,601,709
										Total	**$ 5,040,000**	**$ 4,601,709**

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
874597	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	6/1/2015	6/1/2015	$ 4,000,000	$ 4,000,000	$ 3,549,916
	CLARKSVILLE - MUSKOGEE 345KV CKT 1 OKGE	6/1/2015	6/1/2015	$ 955,000	$ 955,000	$ 897,631
	CLINTON CITY - FOSS TAP 69KV CKT 1	6/1/2010	6/1/2010	$ 75,000	$ 75,000	$ 136,026
	ORU WEST TAP - RIVERSIDE STATION 138KV CKT 1	6/1/2010	6/1/2010	$ 10,000	$ 10,000	$ 18,137
			Total	**$ 5,040,000**	**$ 5,040,000**	**$ 4,601,709**

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
874597	CLASSEN - SW 5TAP 138KV CKT 1	6/1/2010	6/1/2010
	FIXICO TAP - MAUD 138KV AEPW	6/1/2015	6/1/2015
	FIXICO TAP - MAUD 138KV OKGE	6/1/2015	6/1/2015

Customer **Study Number**
SPA **AG1-2005-077**

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
SPA	896846	WFEC	SPA	13	4/1/2006	6/1/2020			$ -	$1,878,712	$ -	$ -
										Total	**$ -**	**$ -**

Reservation	Upgrade Name	COD	EOC	Allocated E & C Cost	Total E & C Cost	Total Revenue Requirements
896846						
			Total	**$ -**	**$ -**	**$ -**

Third Party Reliability Limitation. Customer is not responsible for the mitigation of this constraint.

Reservation	Upgrade Name	COD
896846	ARKANSAS NUCLEAR ONE 161 - RUSSELLVILLE NORTH 161KV CKT 1	6/1/2015

Table 3 - Upgrade Requirements and Solutions Needed to provide Transmission Service for the Aggregate Study

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
AEPW	CLARKSVILLE - MUSKOGEE 345KV CKT 1 AEPW	Rebuild 2.54 miles with 2-795 ACSR & reset Clarksville CT, Replace Switches & Breakers @ Clarksville.	125	15SP	06/01/15	06/01/15	$4,000,000
AEPW	CLINTON CITY - FOSS TAP 69KV CKT 1	Replace Clinton City \wavetrap	15	15SP	06/01/10	06/01/10	$75,000
AEPW	NORTHWEST HENDERSON - OAK HILL #1 138KV CKT 1	Replace wavetrap and reset CTs @ NW Henderson.	0	15SP	06/01/07	06/01/07	$75,000
AEPW	ORU WEST TAP - RIVERSIDE STATION 138KV CKT 1	Replace wavetrap jumpers @ Riverside	0	10SP	06/01/10	06/01/10	$10,000
AEPW	WHITNEY 138/69/12.5KV TRANSFORMER	Move load from 69 kV to 138 kV	0	15SP	06/01/08	06/01/08	$1,750,000
GRDA	412SUB - KANSAS TAP 161KV CKT 1	Reconductor 9.7 miles with 1590MCM ACSR.	0	15SP	06/01/15	06/01/15	$1,488,000
GRDA	412SUB - KERR 161KV CKT 1	Reconductor 12.5 miles with 1590MCM ACSR	0	15SP	06/01/15	06/01/15	$1,918,000
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	125	15SP	06/01/15	06/01/15	$955,000
WR	BELL - PECK 69KV CKT 1	Rebuild 8.23 mile Bell-Peck 69 kV line.	173	15SP	06/01/07	06/01/07	$2,000,000
WR	CRESWELL - OAK 69KV CKT 1	Rebuild substations.	146	15SP	06/01/11	06/01/11	$143,000
WR	GILL ENERGY CENTER WEST - PECK 69KV	Rebuild 10.46 mile Gill-Peck line 138 kV line, but operated at 69 kV	141	06SP	06/01/06	06/01/07	$3,000,000
WR	MIDIAN (MIDIAN1X) 138/69/13.2KV TRANSFORMER CKT 1	Replace Midian 138-69 kV transformer.	0	10SP	06/01/06	06/01/07	$1,500,000
WR	RICHLAND - ROSE HILL JUNCTION 69KV CKT 1	Rebuild 5.43 mile Rose Hill Junction-Richland as a 138 kV line but operate at 69 kV.	187	15SP	06/01/15	06/01/15	$1,500,000
WR	ROSE HILL JUNCTION - WEAVER 69KV CKT 1	Rebuild 5.73 mile Weaver-Rose Hill Junction as a 138 kV line but operate at 69 kV.	143	07SP	06/01/06	06/01/07	$1,600,000

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

Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Date Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	AEP Tulsa Project	AEP Tulsa Project	0	06SH	06/01/06	06/01/07
AEPW	AEPW PLANNED UPGRADE FOR NW ARKANSAS	NW Project phase II scheduled to be in-service 06/2009	0	06SP	04/01/06	06/01/09
AEPW	KNOX LEE - OAK HILL #2 138KV	SPP Expansion Plan Project to Replace relay, wave trap and switch at Knoxlee and switch at Oak Hill #2	0	06SP	06/01/06	06/01/07
WR	CRESWELL - PARIS 69KV CKT 1	Rebuild	119	06SH	06/01/06	06/01/07

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

Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Earliest Date Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
AEPW	ALUMAX TAP - BANN 138KV CKT 1	Replace six (6) 138 kV switches, five at Bann & one at Alumax Tap. Reconductor 0.67 miles of 1024 ACAR with 2156 ACSR. Replace wavetrap & jumpers @ Bann. Replace breaker 3300 @ Bann.	0	10SP	06/01/10	06/01/10
AEPW	ALUMAX TAP - NORTHWEST TEXARKANA 138KV CKT 1	Reconductor 1.68 miles of 1024 ACAR with 2156 ACSR, Replace wavetrap & jumpers with 2156 ACSR. Replace Switch 2285 @ Alumax Tap.	0	07SP	06/01/06	04/01/08
AEPW	FIXICO TAP - MAUD 138KV AEPW	Reconductor 11.83 miles of 3/0 shielded Copperweld with 795 ACSR.	0	15SP	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	0	10SP	06/01/10	06/01/10
OKGE	CLASSEN - SW 5TAP 138KV CKT 1	Replace 800A trap at Classen	0	10SP	06/01/10	06/01/10
OKGE	FIXICO TAP - MAUD 138KV OKGE	Upgrade CT Ratio to 800A	0	15SP	06/01/15	06/01/15
WR	BUTLER 138/69KV TRANSFORMER CKT 1	Replace Butler transformer.	142	15SP	06/01/10	06/01/10

Table 4 - Third Party Facility Constraints

Transmission Owner	Upgrade	Solution	Minimum ATC per Upgrade (MW)	Season of Minimum Allocated ATC	Estimated Engineering & Construction Cost	Earliest Date Upgrade Required (COD)	Estimated Date of Upgrade Completion (EOC)
	None						