Feasibility Study
For
Generation Interconnection
Request
GEN-2004-018

SPP Tariff Studies
(#GEN-2004-018)

January 25, 2005

Executive Summary
<OMITTED TEXT> (Customer) has requested a Feasibility Study for the purpose of interconnecting 800MW of generation within the service territory of Western Farmers Electric Cooperative (WFEC) in Choctaw County Oklahoma. The proposed point of interconnection is by the existing Hugo Switching Station at a new 345kV bus located 10 miles east of Hugo, OK. This switching station is owned by Western Farmers Electric Cooperative. The proposed in-service date is May 1, 2010.

Power flow analysis has indicated that for the powerflow cases studied, it is possible to interconnect the 800MW of generation with transmission system reinforcements within the local WFEC, American Electric Power West (AEPW) and OG&E Electric Services (OKGE) transmission systems. The requirements for interconnection consist of adding two 345kV line terminals in AEPW's Pittsburg and Valliant substations to accommodate new 345kV lines from the Hugo Switching Station. The new 345kV line terminals shall be constructed and maintained by AEPW. The new 345kV line additions shall be constructed and maintained by WFEC in addition to the Hugo 345-138kV 300/400/500MVA Substation addition.

The total estimated cost for WFEC to add its 345kV lines and 345-138kV substation, the interconnection facility, is estimated at $56,600,000. Other Network Upgrades in the AEPW system are required that are listed in Table 1 with an estimated cost of $5,015,000. Therefore, the total estimated cost to the Customer is $61,615,000. This cost does not include building 345kV line from the Customer generation station into the new WFEC Hugo 345-138kV Switching Station.

In Table 3, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer for future analyses including the determination of lower generation capacity levels that may be installed with different financial characteristics given the cost of Network Upgrades. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

The Customer has also requested that this study include the results of an evaluation for the purpose of interconnecting only 350MW of generation at the same location. The total estimated cost for WFEC to add its 138kV lines and terminals in the existing Hugo 138kV substation, the interconnection facility, is estimated at $25,000,000. Other Network Upgrades in the AEPW and OKGE systems are required that are listed in Table 4 with an estimated cost of $4,515,000 and $45,000 in the two systems respectively. Therefore, the total estimated cost to the Customer is $29,560,000. This cost does not include building 138kV line from the Customer generation station into the existing WFEC Hugo 138kV Switching Station.

Introduction

<OMITTED TEXT> (Customer) has requested a Feasibility Study for the purpose of interconnecting 800MW of wind generation within the service territory of Western Farmers Electric Cooperative in Choctaw County Oklahoma. The proposed generation interconnect is within WFEC at a new Hugo 345-138kV Substation. The proposed in-service date is May 1, 2010. The Customer also requested that the interconnect requirements be determined for only 350MW of additional generation.

Interconnection Facilities

The primary objective of this study is to identify the system problems associated with connecting the plant to the area transmission system and estimated costs of system modifications needed to alleviate the system problems. The Feasibility and other subsequent Interconnection Studies are designed to identify attachment facilities, Network Upgrades and other direct assignment facilities needed to accept power into the grid at the interconnection receipt point.

The requirements for interconnection consist of adding a new 345-138kV 300/400/500MVA substation at Hugo and two 345kV lines to AEPW's Pittsburg and Valliant substations. These 345kV and 138kV additions shall be constructed and maintained by WFEC. AEPW's 345kV line terminals and other Network Upgrades shall be constructed and maintained by AEPW.

The total cost for WFEC to add a new Hugo 345-138kV substation, the interconnection facility, is estimated at $5,000,000. WFEC's cost of adding two 345kV lines extending to Pittsburg and Valliant was estimated to be $51,600,000. Other Network Upgrades in the AEPW system are required that are listed in Table 1 at an estimated cost of $5,015,000. Therefore, the total estimated cost to the Customer is $61,615,000. These estimates will be refined during the development of the impact study based on the final designs. This cost does not include building 345kV line from the Customer generating station into the new Hugo 345-138kV Substation. The Customer is responsible for this 345kV line up to the point of interconnection and the cost estimate should be determined by the Customer.

The costs of interconnecting the facility to the WFEC transmission system are listed in Table 1. **These costs do not include any cost that might be associated with short circuit study results or dynamic stability study results**. These costs will be determined when and if a System Impact Study is conducted.

The requirements for interconnection of only 350MW consist of adding 138kV terminals at the Hugo substation at Hugo and two 138kV lines to AEPW's Atoka and Valliant substations. These 138kV additions shall be constructed and maintained by WFEC. AEPW's 138kV line terminals and other Network Upgrades shall be constructed and maintained by AEPW. OKGE's Network Upgrades shall be constructed and maintained by OKGE.

The total cost for WFEC to modify the existing Hugo 138kV substation, the interconnection facility, is estimated at $700,000. WFEC's cost of adding two 138kV lines extending to Atoka and Valliant was estimated to be $24,300,000. Other Network Upgrades in the AEPW and OKGE systems are required that are listed in Table 4 at an estimated cost of $4,560,000. Therefore, the total estimated cost to the Customer is $29,560,000. These estimates will be refined during the development of the impact study based on the final designs. This cost does not include building 138kV line from the Customer generating station into the Hugo 138kV Substation. The Customer is responsible for this 138kV line up to the point of interconnection and the cost estimate should be determined by the Customer.

Table 1: Network Upgrade Facilities

Facility	ESTIMATED COST (2005 DOLLARS)
AEPW – Pittsburg 345kV line terminal addition.	$1,500,000
AEPW – Valliant 345kV line terminal addition.	2,500,000
AEPW – Clarksville 345kV resetting of CTs for the Clarksville - Muskogee 345kV line.	15,000
AEPW – Allen Natural Gas 138kV 3.6MVAR switched capacitor bank addition.	500,000
AEPW – Pittsburg 69kV 3.6MVAR switched capacitor bank addition.	500,000
AEPW – Clarendon 69kV 3.6MVAR switched capacitor bank addition, 6/1/2005 completion.	0
AEPW – Memphis 69kV 3.6MVAR switched capacitor bank addition, 6/1/2005 completion.	0
WFEC - Hugo - Pittsburg 345kV line addition of 70 miles with new 2-conductor 795MCM ACSR.	42,000,000
WFEC - Hugo - Valliant 345kV line addition of 16 miles with new 2-conductor 795MCM ACSR.	9,600,000
WFEC – Hugo 345-138kV 300/400/500MVA Substation addition.	5,000,000
OKGE – Draper Lake 345-138kV, Add 3rd Draper xfrmr at OGE's expense from 7/2/2004 FERC Order on EC03-131-000. Estimated In-Service Date 6/1/2005.	0
OKGE – Muskogee 345kV increase 1500A CT to 2000A in the Clarksville - Muskogee 345kV line by 12/31/2005.	0
Total	**$61,615,000**

Table 2: Direct Assignment Facilities

Facility	ESTIMATED COST (2005 DOLLARS)
Customer - 345kV line between Customer generating station and new Hugo 345-138kV substation.	*
Customer - Right-of-Way for Customer 345kV line.	*
Total	*

Note: *Estimates of cost to be determined by Customer.

Table 3: Contingency Analysis Results

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
CLARKSVILLE - MUSKOGEE 345kV, Reset CTs	10SP, 53794-55224, AEPW TULSA - OKGE MUSKOGEE, RIVERSIDE STATION - MUSKOGEE 345kV.	114.5	0	6/1/2010
DRAPER 345-138kV CKT 2, Add 3rd Draper xfrmr at OGE's expense for "600 MW Bridge" from 7/2/2004 FERC Order on EC03-131-000. Estimated In-Service Date 6/1/2005.	10SP, 54933-54934-55720, OKGE METRO, DRAPER LAKE 345-138kV.	110.3	0	6/1/2010
DRAPER LAKE - DRAPER 3 345-138kV, Add 3rd Draper xfrmr at OGE's expense for "600 MW Bridge" from 7/2/2004 FERC Order on EC03-131-000. Estimated In-Service Date 6/1/2005.	10SP, 54933-54934-55721, OKGE METRO, DRAPER LAKE 345-138kV CKT 2.	110.3	0	6/1/2010
COALGATE 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9676, V CONT = 0.8451.		
ALLEN NATURAL GAS 138kV, Add 3.6MVAR switched capacitor bank.	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9681, V CONT = 0.8414.	0	6/1/2010
COALGATE TAP 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9677, V CONT = 0.8451.		
ALLEN NATURAL GAS TAP 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9693, V CONT = 0.8429.		
ATOKA 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.967, V CONT = 0.849.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due

to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Table 3: Contingency Analysis Results

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
LEHIGH 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.967, V CONT = 0.8461.		
Explorer Colgate Tap 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9685, V CONT = 0.842.		
Explorer Colgate 138kV	10SP, 52800-54006, SWPA AEC - AEPW EASTERN, Tupelo - ALLEN NATURAL GAS TAP 138kV.	V INIT = 0.9685, V CONT = 0.8419.		
PITTSBURG 69kV, Add 3.6MVAR switched capacitor bank.	10SP, 54024-54038, AEPW EASTERN, McALESTER - ARMY AMMUNITION DEPOT 69kV.	V INIT = 0.9693, V CONT = 0.8883. NEW VIOLATION IN TEST CASE.	242	6/1/2010
CLARKSVILLE - MUSKOGEE 345kV	10WP, 53794-55224, AEPW TULSA - OKGE MUSKOGEE, RIVERSIDE STATION - MUSKOGEE 345kV.	101.4	671	
NW Memphis 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.99, V CONT = 0.856. NEW VIOLATION IN TEST CASE.		
JERICHO 115kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 1.0178, V CONT = 0.8291.		
JERICHO 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 1.0151, V CONT = 0.8291.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Table 3: Contingency Analysis Results

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
CLARENDON 69kV, Add 3.6MVAR switched capacitor bank, AEPW project scheduled for 6/1/2005 completion.	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9934, V CONT = 0.8285.	0	12/1/2010
CLARENDON REA 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9925, V CONT = 0.8299.		
HEDLEY 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9902, V CONT = 0.8432.		
NORTH MEMPHIS REA 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9897, V CONT = 0.8534. NEW VIOLATION IN TEST CASE.		
MEMPHIS 69kV, Add 3.6MVAR switched capacitor bank, AEPW project scheduled for 6/1/2005 completion.	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9892, V CONT = 0.8568. NEW VIOLATION IN TEST CASE.	0	12/1/2010
RED RIVER ARSENAL 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9906, V CONT = 0.8819. NEW VIOLATION IN TEST CASE.		
ESTELENE 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV.	V INIT = 0.9917, V CONT = 0.8998. NEW VIOLATION IN TEST CASE.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Table 3: Contingency Analysis Results

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
NW Memphis 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.99, V CONT = 0.8563. NEW VIOLATION IN TEST CASE.		
JERICHO 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 1.0151, V CONT = 0.8295.		
CLARENDON 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9934, V CONT = 0.8288.		
CLARENDON REA 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9925, V CONT = 0.8303.		
HEDLEY 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9902, V CONT = 0.8435.		
NORTH MEMPHIS REA 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9897, V CONT = 0.8538. NEW VIOLATION IN TEST CASE.		
MEMPHIS 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9892, V CONT = 0.8571. NEW VIOLATION IN TEST CASE.		
RED RIVER ARSENAL 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV.	V INIT = 0.9906, V CONT = 0.8822. NEW VIOLATION IN TEST CASE.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Table 4: Network Upgrade Facilities For 350MW

Facility	ESTIMATED COST (2005 DOLLARS)
AEPW - VALLIANT - HUGO POWER PLANT 138kV CKT 2: Add 138kV terminal for Hugo CKT 2.	$1,500,000
WFEC - VALLIANT - HUGO POWER PLANT 138kV CKT 2: Add circuit #2 using 1590 ACSR rated 246/324. Hugo terminal equipment would be 2000A, (478 MVA).	4,800,000
AEPW - CLARKSVILLE - MUSKOGEE 345kV: Reset CTs at Clarksville.	15,000
OKGE - CLARKSVILLE - MUSKOGEE 345kV: Modify CT's & relays for 2000A (1,195MVA) capacity at Muskogee. May require line relay replacement.	0
OKGE - RUSSETT - RUSSETT 138kV: Increase trap and CT at OGE Russett to 1200A.	45,000
AEPW - PITTSBURG 69kV: Add 3.6MVAR switched capacitor bank.	500,000
AEPW - CLARENDON 69kV: Add 3.6MVAR switched capacitor bank. Project scheduled for 6/1/2005 completion.	0
AEPW - Hugo - Atoka 138kV: Construct 138kV Ring Bus at Atoka.	2,500,000
WFEC - Hugo - Atoka 138kV: Add 75 miles 1590kcmil ACSR 138kV line.	19,500,000
WFEC - Hugo 138kV Switching Station: Add 138kV terminals for Valliant Circuit #2, Atoka and line to new generation.	700,000
Total	**$29,560,000**

Table 5: Direct Assignment Facilities For 350MW

Facility	ESTIMATED COST (2005 DOLLARS)
Customer - 138kV line between Customer generating station and existing Hugo 138kV substation.	*
Customer - Right-of-Way for Customer 138kV line.	*
Total	*

Note: *Estimates of cost to be determined by Customer.

Table 6: Contingency Analysis Results For 350MW

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
VALLIANT - HUGO POWER PLANT 138kV CKT 2, Add circuit #2 using 1590 ACSR and add 138kV terminal for Hugo CKT 2.	05AP, 54044-55948, AEPW EASTERN - WFEC , VALLIANT - HUGO POWER PLANT 138kV	107.2 (1)	0	5/1/2010
CLARKSVILLE - MUSKOGEE 345kV, Reset CTs at Clarksville. Modify CT's & relays for 2000A (1,195MVA) capacity at Muskogee. May require line relay replacement.	10SP, 53794-55224, AEPW TULSA - OKGE MUSKOGEE, RIVERSIDE STATION - MUSKOGEE 345kV	106.1	0	6/1/2010
RUSSETT - RUSSETT 138kV, Increase trap and CT at OGE Russett to 1200A.	10WP, 52802-55157, SWPA AEC - OKGE ARDMORE, Brown 138kV	101.9	332	12/1/2010
PITTSBURG 69kV, Add 3.6MVAR switched capacitor bank.	10WP, 54022-54032, AEPW EASTERN, LONE OAK - SOUTH MCALESTER TAP 138kV	V INIT = 0.9877, V CONT = 0.8882.	0	12/1/2010
NW Memphis 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9887, V CONT = 0.8536.		
JERICHO 115kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 1.0162, V CONT = 0.8266.		
JERICHO 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 1.014, V CONT = 0.8266.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.
(1) This loading is when characteristics of circuit #1 were used for new circuit #2. Capacity of circuit #1 will be increased and this AEPW terminal upgrade is assigned to another project.

Table 6: Contingency Analysis Results For 350MW

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
CLARENDON 69kV, Add 3.6MVAR switched capacitor bank. Project scheduled for 6/1/2005 completion.	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.992, V CONT = 0.826.	350	12/1/2010
CLARENDON REA 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9912, V CONT = 0.8274.		
HEDLEY 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9888, V CONT = 0.8407.		
NORTH MEMPHIS REA 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9883, V CONT = 0.851.		
MEMPHIS 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9879, V CONT = 0.8544.		
RED RIVER ARSENAL 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.9891, V CONT = 0.8796.		
ESTELENE 69kV	10WP, 54276-50932, AEPW WTU - SPS SPS-AMA, JERICHO - Kirby 115kV	V INIT = 0.99, V CONT = 0.8976.		
NW Memphis 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9887, V CONT = 0.8539.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Table 6: Contingency Analysis Results For 350MW

Facility	Model & Contingency	Facility Loading (% Rate B) Or Voltage (PU)	ATC (MW)	Date Required (M/D/Y)
JERICHO 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 1.014, V CONT = 0.827.		
CLARENDON 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.992, V CONT = 0.8264.		
CLARENDON REA 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9912, V CONT = 0.8278.		
HEDLEY 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9888, V CONT = 0.8411.		
NORTH MEMPHIS REA 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9883, V CONT = 0.8514.		
MEMPHIS 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9879, V CONT = 0.8548.		
RED RIVER ARSENAL 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.9891, V CONT = 0.8799.		
ESTELENE 69kV	10WP, 54276-54277-54303, AEPW WTU, JERICHO 115-69kV	V INIT = 0.99, V CONT = 0.8979.		

Note: Listed loading of each facility is the highest value when an operating guide is not applicable.
When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations. If the loading of a facility is higher, the level of ATC will be lower.

Powerflow Analysis
A powerflow analysis was conducted for the facility using modified versions of the 2005 April, 2007 and 2010 Summer and Winter Peak models. The output of the Customer's facility was offset in each model by a reduction in output of existing online SPP generation. The proposed in-service date of the generator is May 1, 2010. The available seasonal models used were the 2005 April and 2007 through 2010 peak models. This is the end of the current SPP planning horizon.

The analysis of the Customer's project indicates that, given the requested generation level of 800MW and location, additional criteria violations will occur on the existing AEPW, OKGE and WFEC facilities under steady state conditions in the off-peak and peak seasons. New circuits are required between the new Hugo 345-138kV substation and the existing Pittsburg and Valliant 345kV facilities. To eliminate the overloading of the Clarksville terminal for the Clarksville – Muskogee 345kV line, resetting the CTs is required. To eliminate low voltage conditions, additional capacitor banks are needed at the Allen Natural Gas 138kV and Pittsburg 69kV substations.

For only 350MW of new generation, additional criteria violations will occur on the existing AEPW, OKGE and WFEC facilities under steady state conditions in the off-peak and peak seasons. New circuits are required between the Hugo 138kV substation and the existing Atoka and Valliant 138kV facilities. To eliminate the overloading of the Clarksville terminal for the Clarksville – Muskogee 345kV line, resetting the CTs is required. To eliminate low voltage conditions, an additional capacitor bank is needed at the Pittsburg 69kV substation. Increasing wave trap and CT capacity in the Russett Substation is also required.

Powerflow Analysis Methodology
The Southwest Power Pool (SPP) criteria states that: "The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Planning Standards* for System Adequacy and Security – Transmission System Table I hereafter referred to as NERC Table I) and its applicable standards and measurements".

Using the created models and the ACCC function of PSS\E, single contingencies in the modeled control areas of AEPW, OKGE, Southwestern Power Administration (SWPA) and WFEC were applied and the resulting scenarios analyzed. This satisfies the 'more probable' contingency testing criteria mandated by NERC and the SPP criteria.

Conclusion

The minimum cost of interconnecting the Customer project is estimated at $61,615,000 for WFEC's interconnection facilities including other transmission upgrades by AEPW listed in Table 1 of which are Network Upgrades. At this time, the cost estimates for other Direct Assignment facilities have not been defined by the Customer.

In Table 3, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer to determine lower generation capacity levels that may be installed with different financial characteristics given the cost of Network Upgrades. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations.

To interconnect only 350MW of generation, the minimum cost of interconnecting the Customer project is estimated at $29,560,000 for WFEC's interconnection facilities including other transmission upgrades by AEPW and OKGE listed in Table 4 of which are Network Upgrades. At this time, the cost estimates for other Direct Assignment facilities have not been defined by the Customer.

In Table 6, a value of Available Transfer Capability (ATC) associated with each overloaded facility is included. These values may be used by the Customer to determine lower generation capacity levels that may be installed with different financial characteristics given the cost of Network Upgrades. When transmission service associated with this interconnection is evaluated, the loading of the facilities listed in this table may be greater due to higher priority reservations.

These interconnection costs do not include any cost that may be associated with short circuit or transient stability analysis. These studies will be performed if the Customer signs a System Impact Study Agreement.

The costs do not include any costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer requests transmission service through Southwest Power Pool's OASIS.

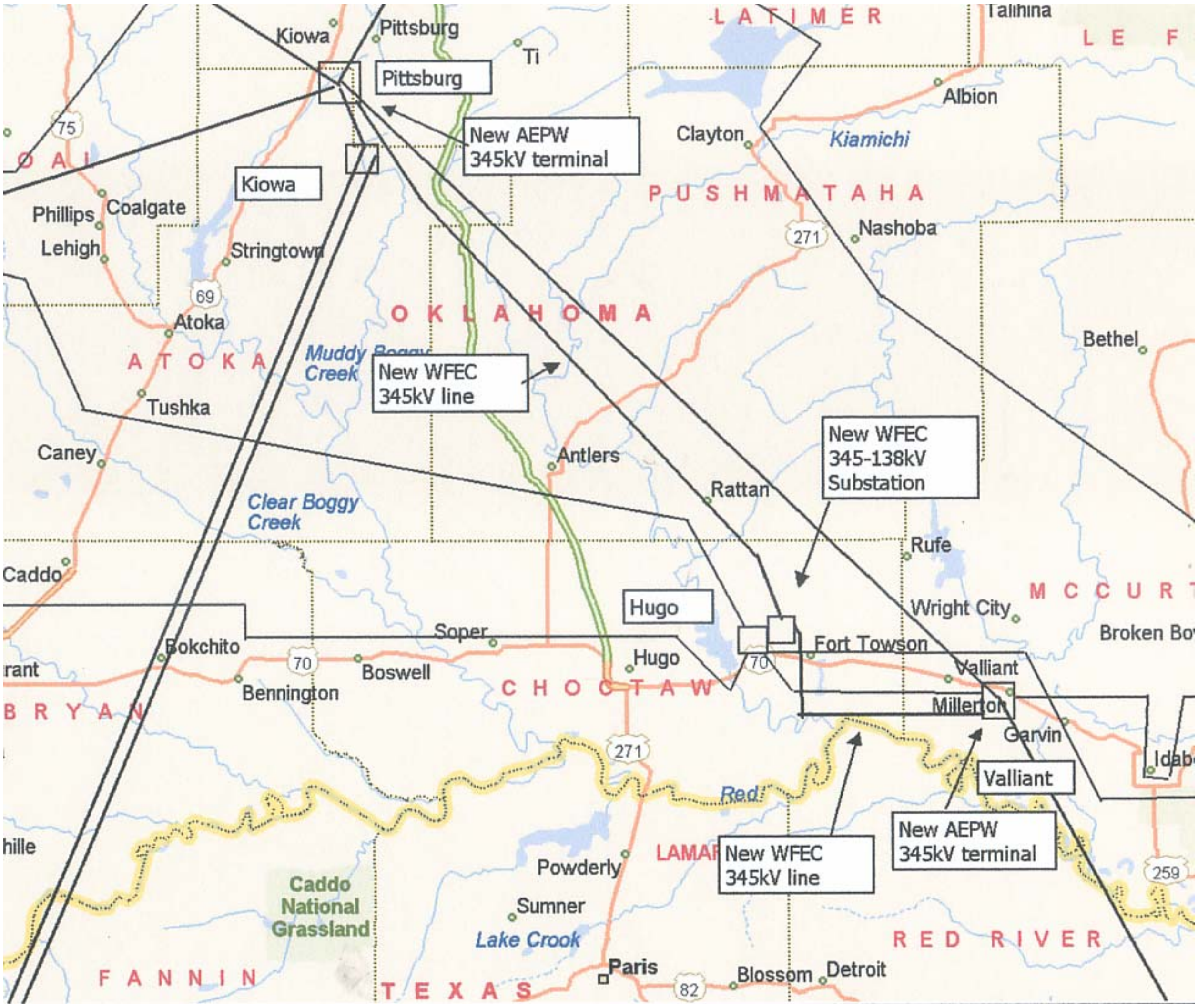

Figure 1: Map Of The Surrounding Area

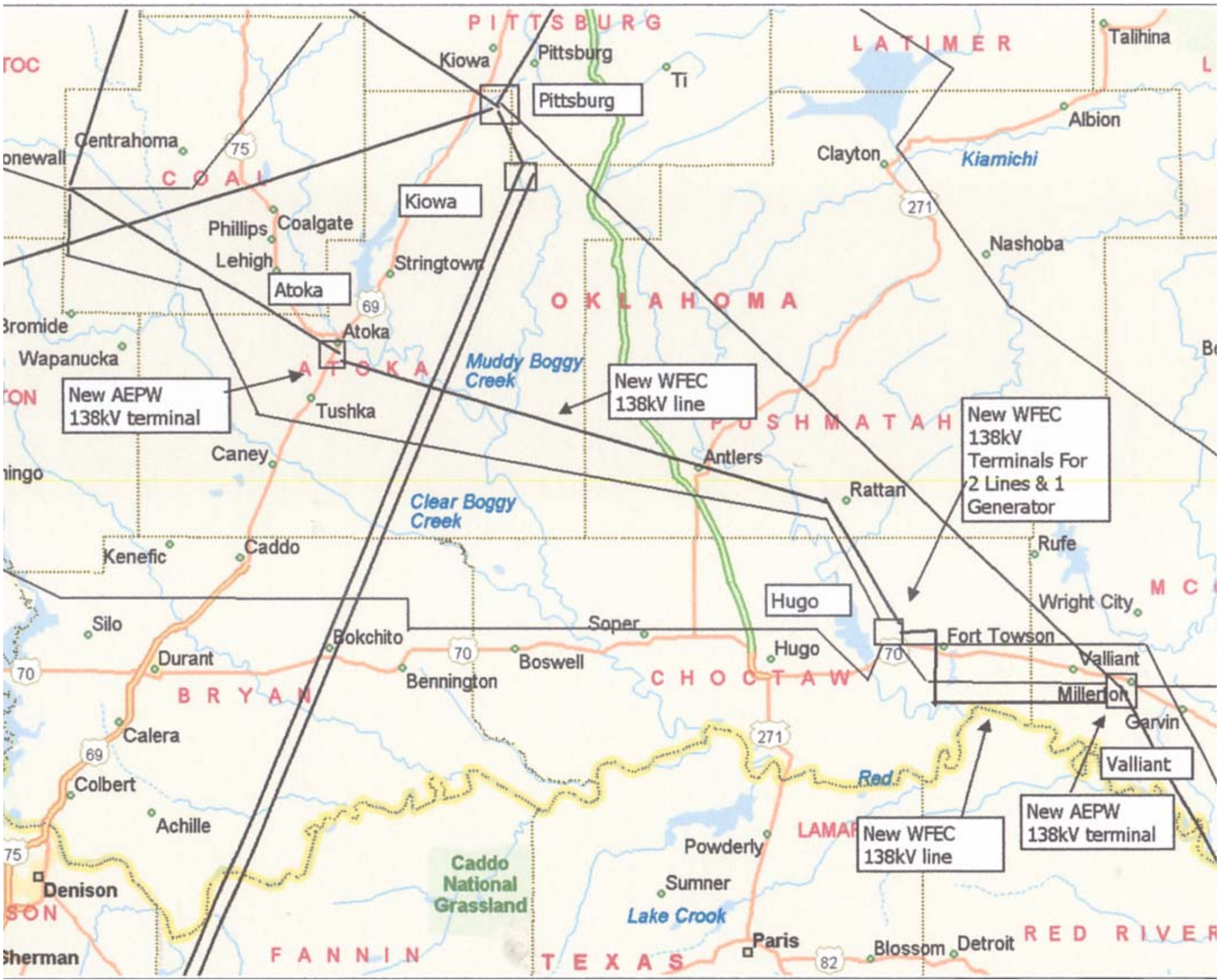

Figure 2: Map Of The Surrounding Area For 350MW