EL PASO ELECTRIC COMPANY

SCHEDULE NO. 29
TRANSMISSION VOLTAGE SERVICE RATE

APPLICABILITY

Available to all commercial and industrial customers who contract for a specified capacity (Minimum Contract Capacity), commensurate with customer's normal firm load requirements, but in no case less than 5,000 kilowatts of capacity. All service will be taken at one point of delivery designated by the Company and through one meter.

TERRITORY

Texas Service Area (C)

TYPE OF SERVICE

Service will be alternating current 60 hertz, three-phase at a transmission voltage of not less than 69,000 volts.

MONTHLY RATE

Demand Charge

$21.25 per kilowatt for all kilowatts of Demand (I)(T)

(D)

Energy Charge

$0.00645 per kilowatt-hour for all kilowatt-hours (I)

MONTHLY MINIMUM

Demand charge for the Minimum Contract Capacity or the applicable minimum demand charge, whichever is greater.

In the event the customer has signed a contract for firm demand in conjunction with interruptible power service, then the monthly demand to be billed under this schedule shall be that amount specified in the power sales agreement for firm and interruptible demand. (N)

DETERMINATION OF DEMAND

Maximum demand will be defined as the highest measured thirty (30) minute average kilowatt load determined by measurement. The measured demand will be adjusted for billing when the metering adjustment clause is applicable.

The demand used for billing shall never be less than 75% of the highest measured on-peak demand (adjusted for metering adjustment if applicable) previously established during billing months of May through October in twelve (12) month period ending with the current month nor less than the minimum contract capacity, whichever is greater. The exception to this will occur when the 1/2 on-peak - 1/2 off-peak provision is invoked. At that time, the measured billing demand shall be used for the purposes of this paragraph.

When the demand established during the off-peak period exceeds the demand

established during the on-peak period, the demand used for billing will be 1/2 the on-peak period demand plus 1/2 the off-peak period demand.

On-peak period shall be from 10:00 A.M. to 8:00 P.M. Mountain Standard time for weekdays of Monday through Friday. Off-peak period shall be all other hours of the week not covered in the on-peak period.

RATING PERIOD SELECTION OPTION

Upon written request by the Customer and approval by the Company, a customer may shift his 10-hour peak period for billing purposes by two (2) hours around the normally defined on-peak period. The Customer may exercise this option twice during the twelve (12) month billing period.

FIXED RATE RIDER

This rider is available to existing or new customers taking service under this schedule with a minimum contractual monthly demand of at least 8,000 KW. Upon the execution of a three (3) year service contract, EPEC will guarantee fixed rates for the non-fuel component of the monthly rate for at least a two (2) year period or for an extended period at the sole discretion of EPEC. The extended period will not exceed three (3) years. Customers requesting to take service under this rider will not be eligible for the Economic Development Rate Schedule No. 33 as discussed in this schedule. (T) (C)

In the event the customer has signed a contract for firm demand in conjunction with interruptible power service, then the terms of this rider are not available to the customer unless expressly allowed by EPEC. Such allowance is at the sole discretion of EPEC. (N)

PROTECTIVE EQUIPMENT

Customer shall provide, at his expense, suitable relaying equipment and devices as specified by the Company so as to protect the Company's System and its service to other electric users from disturbances or faults that may occur on customer's system and equipment. Customer will provide at his expense all voltage regulating devices that are required.

FACILITIES CHARGE

In the event the Company is required to install and operate additional transmission plant, switching stations or transformation to meet the customer's requirements, a Facilities Charge shall be included under this rate. The installed cost of metering shall be included in determination of the Facilities Charge.

METERING ADJUSTMENT

The Company may, at its option, meter the customer's electrical usage on the low voltage side of customer's substation transformer, in which case the metered quantities will be increased by a percentage which will be based upon calculated transformer losses.

POWER FACTOR ADJUSTMENT

If the power factor at the time of the highest measured thirty (30) minute interval kilowatt demand for the entire plant is below 90% lagging, a charge of $0.0700 per KVAR will be

made for each KVAR by which customer's computed KVAR demand exceeds 48.432% of the measured kilowatt, or adjusted kilowatt demand, whichever is applicable. If the power factor is greater than or equal to 90%, then no power factor adjustment will be made.

FIXED FUEL FACTOR

The above rates are subject to the provisions of Company's Tariff Schedule No. 98 entitled Fixed Fuel Factor.

EXPERIMENTAL ECONOMIC RECOVERY RIDER (D)

TERMS OF PAYMENT

The due date of the bill for utility service shall not be less than sixteen (16) days after issuance. A bill becomes delinquent if not received at the Company by the due date.

TERMS AND CONDITIONS

The Company's Rules and Regulations apply to service under this schedule. The Term of Contract under this schedule shall be not less than ten (10) years.

Should a customer be eligible and EPEC elects to provide service under Rate Schedule No. 27 in conjunction with service under this schedule, the provisions of Rate Schedule No. 27 and the customer's Contract for Power Service shall prevail over any inconsistent or otherwise conflicting provisions set forth herein. (T)

EL PASO ELECTRIC COMPANY

SCHEDULE NO. 27
INTERRUPTIBLE POWER SERVICE RATE (N)

APPLICABILITY

Available to all commercial and industrial customers with total firm capacity requirements of at least 5,000 KW, at the sole discretion of the Company and only when the Company has available capacity in excess of its firm system requirements. Interruptible Power Service is available under this schedule only if the utilization of such service is of such character that such service is capable of being interrupted at any time upon request without damage to property or persons and without adversely affecting the public health, safety, and welfare. This schedule is not available for standby, temporary, resale, or interruptible service not in conjunction with other firm service.

TERRITORY

Texas Service Area

TYPE OF SERVICE

Service will be alternating current 60 hertz, three-phase at a transmission voltage of not less than 69,000 volts.

MONTHLY RATE

The monthly charge for interruptible power service hereunder, excluding fuel, shall be comprised of the following rate elements:

(a) a demand charge calculated by multiplying (i) Customer's Interruptible Power Billing Demand times (ii) the quotient of EPEC's test year Texas-jurisdictional demand-related transmission costs divided by the sum of the loss-adjusted non-coincident peak demands on an adjusted test-year basis for all of EPEC's Texas retail classes that receive firm service; plus

(b) an energy charge calculated by multiplying (i) the Customer's monthly Interruptible Energy times (ii) the quotient of EPEC's test year Texas-jurisdictional production- and transmission-related non-fuel variable O&M expenses divided by EPEC's adjusted test year Texas-jurisdictional KWH sales at supply; plus

(c) an adder on EPEC's interruptible sales to Customer equal to $.00325 per KWH of Interruptible Energy.

For purposes of calculating the above rates, test year demand-related transmission costs, adjusted test year loss-adjusted non-coincident peak demands, test year production- and transmission-related non-fuel variable O&M expenses, and adjusted test year KWH sales at supply, shall be as determined by the Texas Public Utility Commission rate order in EPEC's most recent general rate case. In the event EPEC has not filed for a rate increase with the Texas Public Utility Commission within two years following the date of entry of the final order in EPEC's last general rate case, or should it be impossible to determine the information necessary to calculate the above rates from the data underlying EPEC's most recent rate order, EPEC and the Customer shall then in that event mutually agree upon the information to be used for the following twelve month period to calculate the above rates.

EL PASO ELECTRIC COMPANY

SCHEDULE NO. 27
INTERRUPTIBLE POWER SERVICE RATE (N)

The rates for interruptible power service hereunder shall not be subject to any penalties or rewards associated with performance standards applicable to the Palo Verde Nuclear Generating Station.

FIXED FUEL FACTOR

The above rates are subject to the provisions of Company's Tariff Schedule No. 98 entitled Fixed Fuel Factor.

DETERMINATION OF DEMAND AND ENERGY

Maximum demand will consist of both firm and interruptible demand, and will be defined as the highest thirty (30) minute average kilowatt load determined by measurement. The measured demand will be adjusted for billing when the metering adjustment clause is applicable.

When the maximum demand established during the off-peak period exceeds the maximum demand established during the on-peak period, the Total Billing Demand will be 1/2 of the maximum demand established during the on-peak period plus 1/2 of the maximum demand established during the off-peak period. Otherwise, the Total Billing Demand will be the maximum demand established during the on-peak period. In no event shall Total Billing Demand be less than the Minimum Firm Contract Capacity specified in the Contract for Power Service.

The on-peak period shall be from 10:00 A.M. to 8:00 P.M. Mountain Standard Time for weekdays of Monday through Friday. The off-peak period shall be all other hours of the week not covered in the on-peak period.

Firm Power Billing Demand shall be the lesser of (1) the Total Billing Demand or (2) the Contract Firm Power Demand established in the Contract for Power Service, but not less than the Minimum Firm Contract Capacity specified in the Contract for Power Service.

Firm Power Billing Demand as defined herein shall constitute the "demand used for billing" under the Customer's firm service rate schedule, and shall be billed in accordance with the rate schedule applicable to Customer's firm service. Interruptible Power Billing Demand shall be determined as (1) Total Billing Demand less (2) Firm Power Billing Demand, and shall be billed in accordance with this rate schedule.

Firm Energy shall be determined by multiplying the ratio of the Firm Power Billing Demand to the Total Billing Demand times the metered kilowatt-hours. Firm Energy shall be billed in accordance with the rate schedule applicable to Customer's firm service. Interruptible Energy shall be the difference between the metered kilowatt-hours and the Firm Energy. Interruptible Energy shall be billed in accordance with this rate schedule.

eg $\frac{25000}{50000} \times 32,850,000$

$= 16,425,000$

EL PASO ELECTRIC COMPANY

SCHEDULE NO. 27
INTERRUPTIBLE POWER SERVICE RATE (N)

RATING PERIOD SELECTION OPTION

Upon written request by the Customer and approval by EPEC, Customer may shift his 10-hour peak period for billing purposes by two (2) hours around the normally defined on-peak period. Customer may exercise this option twice during the twelve (12) month billing period.

CONTRACT FOR SERVICE

A Contract for Power Service ("Contract") must be executed between EPEC and the Customer prior to taking service under this rate schedule. The Contract shall establish the amount of the Customer's demand that shall be served as firm demand. All demand in excess of the amount of firm demand specified in the Contract shall constitute interruptible demand and shall be served and billed on that basis. The Contract term shall be for an initial period of three (3) years, and shall continue year-to-year thereafter until canceled by either party upon one (1) year's prior written notice. The amount of Contract Firm Power Demand and Minimum Firm Contract Capacity specified in the Contract will supersede and control over any inconsistent level of demand specified in any preexisting agreement between EPEC and the Customer.

SCHEDULING PROCEDURES

The Company and the Customer shall agree upon detailed procedures for requesting, providing notice of, and implementing interruptions, and shall set forth the same in the Contract for Power Service.

GENERAL CONDITIONS

EPEC may make intentional interruptions at any time and from time to time, at EPEC's sole discretion, for up to 400 hours in any calendar year. However, EPEC may not interrupt the customer (1) due solely to differences in EPEC's marginal cost of energy and the energy-related charges for Interruptible Power Service, or (2) to continue or make non-firm off-system sales. In the event of an interruption for non-emergency purposes, EPEC will provide at least 4 hours notice prior to interruption. In the event of an interruption for emergency conditions, EPEC will attempt to provide as much prior notice as possible but is in no way obligated to give more than 30 minutes notice prior to interruptions. Emergency conditions are deemed to exist at any time, in the judgment of EPEC, that demands for electricity exceed or are expected to be likely to exceed EPEC's available electric supply for whatever reasons including, but not limited to, breakdown of generating units, transmission equipment or other critical facilities; short or long term shortages of fuel or generation, transmission, and other facilities, and requirements or orders of governmental agencies. An hour of interruption shall be any clock-hour or part thereof during which EPEC invokes an intentional interruption. The number of hours of interruption remaining in a calendar year shall be reduced by a minimum of four hours for each interruption occasion, even though the actual interruption may last for a lesser time period. No more than two interruptions may be required in any calendar day.

EL PASO ELECTRIC COMPANY

SCHEDULE NO. 27
INTERRUPTIBLE POWER SERVICE RATE (N)

NON-COMPLIANCE

Customer understands that service under this rate is contingent upon Customers' complete and timely compliance with EPEC's requests for interruption. If, at any time, Customer fails in whole or in part to implement and maintain any requested load reduction or interruption, Customer shall pay to EPEC as agreed damages, 20 percent of the current month's bill for Interruptible Power Service for each such occurrence. An occurrence shall be defined as non-compliance, in whole or in part for each calendar day subsequent to EPEC's request for interruption. If Customer fails to comply on three separate occasions within a 12-month period, EPEC may, in addition to the damages above, elect to terminate, effective immediately, Interruptible Power Service under the Customer's Contract for Power Service. Customer shall not be required to interrupt load as requested by EPEC if interruption would result in aggregate interruptions that exceed the daily or annual limitations on interruptions set forth herein. In the first 12 months of Interruptible Power Service to Customer, EPEC will not enforce the provisions of this non-compliance section if the actual reductions are equal to or greater than 90% of the requested reduction on each occasion.

TERMS OF PAYMENT

The due date of the bill for utility service shall not be less than sixteen (16) days after issuance. A bill becomes delinquent if not received at the Company by the due date.

OTHER TERMS AND CONDITIONS

During the term of the Customers' Contract for Power Service, Customer may not engage in self-generation other than periodic operation of any existing self-generation facilities, not to exceed a total capacity of 10,000 KW, in place on Customer's premises as of the date of initial execution of the Contract for Power Service.

Interruptible sales under this rate schedule are non-firm sales and as such are not subject to cost-of-service allocations in any EPEC rate case.

The Company's Rules and Regulations apply to service under this schedule.

EL PASO ELECTRIC COMPANY
INTERRUPTIBLE RATE CALCULATION
TRANSMISSION VOLTAGE CUSTOMER
FOR THE TEST YEAR ENDED JUNE 30, 1993

Line No.	Demand Charge Calculation	Value	Source
1	Total Transmission Plant	$162,114,000	Page 2 of 18 Commission Jurisdictional COS Study
2	Accum. Depr. Transmission	45,125,000	Page 3 of 18 Commission Jurisdictional COS Study
3	Net Transmission Plant	$116,989,000	Line 1 minus Line 2
4	Consolidated factor	10.34451173%	Page 2, Line 11
5	Rate Base Related Revenue Req.	$12,101,941	Line 3 times Line 4
6	Transmission O&M Expense	606,000	Page 5 of 18 Commission Jurisdictional COS Study
7	Transmission Depreciation Exp.	5,011,000	Page 7 of 18 Commission Jurisdictional COS Study
	Transmission Property Tax		
8	Palo Verde Transmission	294,000	Page 8 of 18 Commission Jurisdictional COS Study
9	AIP Transmission	594,000	Page 8 of 18 Commission Jurisdicitional COS Study
10	Other Trans. Direct	4,000	Page 8 of 18 Commission Jurisdicitional COS Study
11	Other Transmission	515,000	Page 8 of 18 Commission Jurisdictional COS Study
12	Total Transmission Property Tax	1,407,000	Sum of Lines 8, 9, 10, 11
13	Demand Related Transmission Costs	$19,125,941	Sum of Lines 5, 6, 7, 12
14	Texas Class Loss-Adjusted Non-Coincident Peak Demands (Less Interruptible demands)	1,045,771	Page 3 of 28 - EPEC Schedule O-1.4
15	Annual Demand Charge ($/kW)	$18.29	Line 13 divided by Line14
16	Monthly Demand Charge ($/kW)	**$1.52**	Line 15 divided by 12

EL PASO ELECTRIC COMPANY
INTERRUPTIBLE RATE CALCULATION
TRANSMISSION VOLTAGE CUSTOMER
FOR THE TEST YEAR ENDED JUNE 30, 1993

INTERIM ORDER
DOCKET NO. 12700

Line No.	Demand Charge Calculation	Value	Source
1	Cost of Capital	9.13964040%	Commission Schedule KS-2
2	Long-Term Debt	7.27000000%	Page 29 of 101 - EPEC COS based on Commission COS
3	After-Tax Taxable Return	1.86964040%	Line 1 minus Line 2
4	FIT Factor (1/(1-TR))	1.538461538	Page 12 of 18 Commission Jurisdictional COS Study
5	Before-FIT Taxable Return	2.87636985%	Line 3 times Line 4
6	SIT Factor	1.03493590	State Income Tax Calculation Workpaper
7	Before-FIT/SIT Taxable Return	2.97685842%	Line 5 times Line 6
8	Revenue-Related Tax Factor	1.03280415	Page 29 of 101 - EPEC COS based on Commission COS
9	Before-Tax Taxable Return	3.07451173%	Line 7 times Line 8
10	Long-Term Debt	7.27000000%	Line 2
11	Consolidated Factor	10.34451173%	Line 9 plus Line 10

EL PASO ELECTRIC COMPANY
INTERRUPTIBLE RATE CALCULATION
TRANSMISSION VOLTAGE CUSTOMER
FOR THE TEST YEAR ENDED JUNE 30, 1993

INTERIM ORDER
DOCKET NO. 12700

Line No.	Demand Charge Calculation	Value	Source
1	A501 Non-Reconcilable Fuel	$244,000	Page 4 of 18 Commission Jurisdictional COS Study
2	A512 Maintenance of Boiler Plant	1,554,000	Page 4 of 18 Commission Jurisdictional COS Study
3	A513 Maintenance of Electric Plant	1,534,000	Page 4 of 18 Commission Jurisdictional COS Study
4	A530 Maintenance of Reactor Plant	3,422,000	Page 4 of 18 Commission Jurisdictional COS Study
5	A531 Maintenance of Electric Plant	2,594,000	Page 4 of 18 Commission Jurisdictional COS Study
6	Texas Class Non-Fuel Variable O&M Expenses	$9,348,000	Sum of Lines 1, 2, 3, 4, 5
7	Texas Class kWh at Supply (Less Interruptible kWh)	4,243,464,725	Page 1 of 28 - EPEC Schedule O-1.4
8	Energy Charge ($/kWh)	**$0.00220**	Line 6 divided by Line 7

EL PASO ELECTRIC COMPANY

EXHIBIT TLN-1
PAGE 1 OF 1

SCHEDULE NO. 98 - FFF
FIXED FUEL FACTOR

APPLICABILITY

Electric service billed under rate schedules having a Fixed Fuel Factor Clause shall be subject to a Fixed Fuel Factor.

TERRITORY

Texas Service Area

FORMULA

The Fixed Fuel Factors recognize loss adjustments due to different voltage levels of service:

	Energy Loss Factor	Fixed Fuel Factor ($/KWH)	
A. Texas System	1.00000	0.03631	(I)
B. Transmission Voltage (If customer is not specified below and takes service and is metered at 69,000 volts and higher)			
Schedule No. 15	0.94669	0.03437	(I)
Schedule No. 24/44	0.94669	0.03437	(I)
Schedule No. 24	0.94050	0.03415	(I)
Schedule No. 25	0.94669	0.03437	(I)
Schedule No. 26	0.93665	0.03401	(I)
Schedule No. 30, 27	0.93774	0.03405	(I)
Schedule No. 31, 27	0.93665	0.03401	(I)
C. Primary Voltage (If customer takes service and is metered at 2,400 volts or higher but less than 69,000 volts)	0.96302	0.03497	(I)
D. Secondary Voltage (If customer takes service and is metered at 480 volts and below)	1.01564	0.03688	(I)

EL PASO ELECTRIC COMPANY

SCHEDULE NO. 98 - FFF
FIXED FUEL FACTOR

APPLICABILITY

Electric service billed under rate schedules having a Fixed Fuel Factor Clause shall be subject to a Fixed Fuel Factor.

TERRITORY

Texas Service Area

FORMULA

The Fixed Fuel Factors recognize loss adjustments due to different voltage levels of service:

	Energy Loss Factor	Fixed Fuel Factor ($/KWH)	
A. Texas System	1.00000	0.03056	(I)
B. Transmission Voltage (If customer is not specified below and takes service and is metered at 69,000 volts and higher)			
Schedule No. 15	0.95014	0.02904	(I)
Schedule No. 24/44	0.95014	0.02904	(N)
Schedule No. 24	0.94438	0.02886	(I)
Schedule No. 25	0.95014	0.02904	(I)
Schedule No. 26	0.94079	0.02875	(I) (D)
Schedule No. 30, 27	0.94079	0.02875	(T),(I)
Schedule No. 31, 27	0.94079	0.02875	(T),(I)
C. Primary Voltage (If customer takes service and is metered at 2,400 volts or higher but less than 69,000 volts)	0.96536	0.02950	(I)
D. Secondary Voltage (If customer takes service and is metered at 480 volts and below)	1.01441	0.03100	(I)

used this in fuel adj average in prior int study # 8309

ARKANSAS PUBLIC SERVICE COMMISSION

Revised	Sheet No. 19		
Replacing	Sheet No. 19	Issued	10-04-01
Name of Company:	THE EMPIRE DISTRICT ELECTRIC COMPANY		
Kind of Service:	Electric	Class of Service:	All
Issue Date:		Effective Date:	5-14-05

Part III. Rate Schedule No.: 6

Title: **TRANSMISSION SERVICE** (Schedule PT) PSC File Mark Only

6. TRANSMISSION SERVICE

6.1. AVAILABILITY:
This schedule is available for electric service to any General Service Customer except those who are conveying electric service received to others whose utilization of same is for residential purposes other than transient or seasonal. Motels, hotels, inns, resorts, etc., and others who provide transient room and board service or room service and/or provide service to dwellings on a transient or seasonal basis are not excluded from the use of this rate. The Company reserves the right to determine the applicability or the availability of this rate to any specific applicant for electric service.

6.2. MONTHLY RATE:

	Summer Season	Winter Season	(AT) (RT)
CUSTOMER CHARGE.....	$ 170.00	$ 170.00	(CR)
DEMAND CHARGE, per kW.....	11.45	7.70	(CR)
ENERGY CHARGE			
First 350 hours use of Metered Demand, per kWh.....	0.0064	0.0064	(CR)
Additional hours use of Metered Demand, per kWh....	0.0032	0.0032	(CR)

6.3. METERING: (AT)
The Company would prefer an analog telephone line to the metering location(s) for use by the Company to retrieve interval metering data for metering and load research purposes. This telephone line should be available to the Company between the hours of midnight and 6:00 am each day.

6.4. DETERMINATION OF BILLING DEMAND: (MT)
The Billing Demand will be determined from the highest fifteen (15) minutes integrated kilowatt demand registered during the month by a suitable demand meter, but no Billing Demand will be less than 65% of the highest such demand established during the year ending with the current month and in no event will the Billing Demand be less than 1000 kW.

ARKANSAS PUBLIC SERVICE COMMISSION

Revised	Sheet No. 20		
Replacing	Sheet No. 20	Issued	10-04-01
Name of Company:	THE EMPIRE DISTRICT ELECTRIC COMPANY		
Kind of Service:	Electric	Class of Service:	All
Issue Date:		Effective Date:	5-14-05

Part III. Rate Schedule No.: 6

Title: **TRANSMISSION SERVICE** (Schedule PT) PSC File Mark Only

6.5. TRANSFORMER OWNERSHIP: (MT)
Service will be supplied and metered at the voltage of the Company's primary system. Where the Company supplied facilities (other than metering equipment) for the utilization of service at a voltage lower than that of the Company's primary line feeding to such location, the above Demand Charge will be increased by 5%. See also Rider XC.

6.6. METERING ADJUSTMENT: (MT)
The above rate applies for service metered at primary voltage. Where service is metered at secondary voltage, an adjustment will be made by increasing metered kilowatts and metered kilowatt hours by dividing metered kilowatt and metered kilowatt hours by 97%.

6.7. MINIMUM MONTHLY BILL: (MT)
The minimum bill for any month will be the Customer Charge plus the Demand Charge.

6.8. ENERGY COST RECOVERY: (MT)
The above energy charges will be adjusted in an amount provided by the terms and provisions of Rate Schedule 16, Energy Cost Recovery, Rider ECR.

6.9. PAYMENT: (MT)
Bills will be due on or before fourteen (14) days after the mail date of bill.

6.10. GROSS RECEIPTS, OCCUPATION OR FRANCHISE TAXES: (MT)
There will be added to the Customer's bill, as a separate item, an amount equal to the proportionate part of any license, occupation, franchise, or other similar fee or tax now or hereafter imposed upon the Company by any municipality or any other governmental authority, whether imposed by ordinance, franchise, or otherwise, in which the fee or tax is based upon a percentage of gross receipts, net receipts, or revenues from the sale of electric service rendered by the Company to the Customer. Bills will be increased the proportionate amount only in service areas where such tax is applicable.

6.11. CONDITIONS OF SERVICE: (MT)

6.11.1. Voltage, phase and frequency of service will be as approved by the Company.

6.11.2. More than one class of service, as to character of voltage, phase or frequency, if separately metered, will not be combined for billing.

6.11.3. Service will be supplied through a single meter unless otherwise authorized by the Company. The point of delivery and location of the meter will be at the building wall unless otherwise specifically designated and approved in advance by the Company for each exception.

6.11.4. Service will be furnished for the sole use of the Customer, and will not be resold, redistributed, or submetered, directly or indirectly.

6.11.5. The term of service will not be less than one (1) year. Intermittent or seasonal service will not be provided.

6.11.6. Bills for service will be rendered monthly.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 37

Replacing Sheet No. 37 Issued 4/10/95

Name of Company: THE EMPIRE DISTRICT ELECTRIC COMPANY

Kind of Service: Electric Class of Service: All

Issue Date: 8-24-98 Effective Date:

Part III. Rate Schedule No.: 18

Title: **INTERRUPTIBLE SERVICE** (Rider IR) PSC File Mark Only

18. INTERRUPTIBLE SERVICE

18.1. APPLICATION:
This rider is available to Commercial or Industrial Customers on General Power Service (GP) or Transmission Service (PT) rates, with a minimum monthly billing demand of 1000 kilowatts (kW), and a minimum load curtailment capability of 500 kW. Customers must sign an interruptible contract and meet all special conditions listed below.

18.2. MONTHLY RATE:
Customer Charge ..... $ 28.40
Credit on Demand Reduction, per kW (CT)
Schedule GP Customer ..... 33% of Demand Charge (CT) (CR)
Schedule ~~PT~~ Customer ..... 21.5% of Demand Charge (CT) (CR)

18.3. BILLING DEMAND:
The minimum monthly billing demand for all Customers on this rider shall be 1000 kW.

18.4. DEMAND REDUCTION:
The Customer shall receive a credit on his monthly bill for each month of the contract year. The amount of this credit will be based on the contracted demand reduction. The Customer will be entitled to this credit if the Customer's actual demand reduction for all interruption periods during the contract year is equal to or greater than the contract amount. The actual demand reduction shall be defined as the difference between the Customer's monthly billing demand and the Customer's maximum demand during interruption periods for that month.

18.5. CREDIT:
If the Schedule GP Customer meets the demand reduction requirements above, a credit equal to the contracted demand reduction times 33% of the price of the Demand Charge of the Schedule GP rate under which the Customer received service shall be given for the twelve (12) months of the contract. If the Schedule PT Customer meets the demand reduction requirements above, a credit equal to the contracted demand reduction times 21.5% of the price of the Demand Charge of the schedule PT rate under which the Customer received service shall be given for the twelve (12) months of the contract. If the Customer fails to reduce demand by the contracted amount then all credits previously allowed during the current contract year shall be repaid. All repayable credits for the months preceding interruption failure hall be billed the month following failure to interrupt, and no further credits shall be allowed for the contract year. (CT) (CR)

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 38

Replacing Sheet No. 38 Issued 4/10/95

Name of Company: THE EMPIRE DISTRICT ELECTRIC COMPANY

Kind of Service: Electric Class of Service: All

Issue Date: 8-24-98 Effective Date:

Part III. Rate Schedule No.: 18

Title: **INTERRUPTIBLE SERVICE** (Rider IR) PSC File Mark Only

18.6. SPECIAL CONDITIONS OF SERVICE:

18.6.1. This rider requires a service contract which specifies the amount of demand available for reduction. The contracted demand reduction shall not be less than 500 kW. The Company shall notify the Customer before December 1 prior to the contract year of the amount of interruptible credit available. The Customer shall sign the interruptible contract by December 31 prior to the contract year. Contract years shall run from June 1 to May 31 of the following year. The interruptible annual contract shall specify the daily reduction period.

18.6.2. The Company reserves the right to assure itself that any contracted level of load subject to reduction has a reasonable probability of being on the Company's system during peak load periods and can be readily reduced.

18.6.3. The Customer will be responsible for monitoring his load in order to comply with the terms of the contract.

18.6.4. The Company shall have no liability to the Customer or to any other person, firm, or corporation for any loss, damage, or injury by reason of any interruption or curtailment as provided herein.

18.6.5. The Customer will not be required to reduce demand more than 400 hours per contract year.

18.6.6. The Company shall give the Customer a minimum of one (1) hour notice prior to demand reduction, unless mutually agreed to by Company and Customer and so specified in the annual contract.

18.6.7. This service will be available to a maximum of ten (10) Customers for an experimental period of one (1) year. The Company may extend availability from year to year and increase the number of Customers.

18.6.8. Except as provided herein, all terms and provisions of the applicable rate schedule will be in full force and effect.

18.6.9. Credits shall be applied to bills the month after such credits are earned.

ARKANSAS PUBLIC SERVICE COMMISSION

Revised	Sheet No. 34		
Replacing	Sheet No. 34	Issued	4/10/95
Name of Company:	THE EMPIRE DISTRICT ELECTRIC COMPANY		
Kind of Service:	Electric	Class of Service:	All
Issue Date:		Effective Date:	8-24-98

Part III. Rate Schedule No.: 16

Title: **ENERGY COST RECOVERY RIDER** (Rider ECR) PSC File Mark Only

16. ENERGY COST RECOVERY RIDER (CT)

16.1. AVAILABILITY:
This Energy Cost Recovery Rider is available to the Company for application on rate schedules in this Tariff only. (CT)

16.2. APPLICABILITY:
The Energy Cost Rate shall recover the Company's net fuel and purchased energy cost as defined in this rider and shall be applied to each customer's monthly kilowatt-hours billed under the Company's rate schedules herein subject to this rider by reference. (CT)

16.3. ENERGY COST RATE FORMULA: (CT)
The charge or credit per kilowatt-hour, rounded to the nearest one-thousandth of a cent shall be determined as follows:

$$ECR = \text{Energy Cost Rate} \quad \text{(CT)}$$

$$ECR = \frac{TUA + (PEC * EAF)}{PES} \quad \text{(CT)}$$

Where: TUA = True-up adjustment for the energy cost period including carrying charges (1). (CT)

$$TUA = \sum_{j=1}^{12} (EC_j * EAF - (RR_j - PTU_j)) * (1 + CCR * \frac{(21-j)}{12}) \quad \text{(CT)}$$

Where: EC_j = Energy cost for month $_j$ of the energy cost period. (CT)

$EC_j = FE_j + PEj.$ (CT)

Where:

FE_j = Fuel expense charged to accounts 501 and 547 in month $_j$ of the energy cost period. (CT)

PE_j = Purchased energy expense charged to account 555 in month $_j$ of the energy cost period (2). (CT)

EAF = Energy cost allocation factor most recently approved by the commission for application in this Rider ECR (3). (CT)

RR_j = Revenue under Rider ECR for month $_j$ of the energy cost period. (CT)

PTU_j = Prior period true-up adjustment applicable for month $_j$ of the energy cost period (4).(CT)

CCR = Carrying charge rate (5). (CT)

PEC = Projected energy cost for the projected energy cost period (6). (CT)

$$PEC = \sum_{J=1}^{12} EC_j \ (7)$$ (CT)

PES = Projected energy sales (kWh) subject to this Rider ECR for the projected energy cost period. (CT)

16.4. NOTES TO FORMULA:

(1) The Energy Cost Period is the calendar year immediately preceding the filing year. (CT)

(2) Only energy related-portion of Account 555 shall be included in calculation. (CT)

(3) The initial effective value of the EAF shall be 0.0311. (CT)

(4) The value of PTU_j for month $_j$ of the then current Energy Cost Period shall be equal to one-twelfth of the True-up Adjustment (TUA) previously determined under the provisions of this Rider ECR for the second preceding Energy Cost Period for j=1,3 (January through March) and equal to one-twelfth of the True-up Adjustment (TUA) for the immediately preceding Energy Cost Period for j=4, 12(April through December). (CT)

(5) The Carrying Charge Rate shall be the authorized rate of return on rate base most recently approved for Empire by the Commission in a non-appealable final order. The initial Carrying Charge shall be 7.718%. (CT)

(6) The projected Energy Cost Period is the twelve month period commencing on April 1 of the filing year. The Projected Energy Cost is the energy costs recorded in Accounts 501, 547, and 555 for the calendar year immediately preceding the filing year. (CT)

(7) Should there be unusual circumstances associated with any Projected Cost Period either the Company or Staff may propose use of a Projected Energy Cost (Variable PEC) different from that defined by this formula. (CT)

ARKANSAS PUBLIC SERVICE COMMISSION

Revised	Sheet No. 35.1		
Replacing	Sheet No. _____	Issued	_____
Name of Company:	THE EMPIRE DISTRICT ELECTRIC COMPANY		
Kind of Service:	Electric	Class of Service:	All
Issue Date:	_____	Effective Date:	5-14-05

Part III. Rate Schedule No.: 16

Title: **ENERGY COST RECOVERY RIDER** (Rider ECR) PSC File Mark Only

16.5. ATTACHMENT A: (AT)

If, prior to the annual redetermination of the Energy Cost Rate, Staff or the Company becomes aware of an event that is reasonably expected to occur and/or has occurred which will materially impact the company's Energy Cost, either the Staff or the Company may propose an adjustment to the Energy Cost Rate Formula set out in Rider ECR. Furthermore, should a cumulative over-recovery or under-recovery balance arise during any Rider cycle which exceeds ten percent (10%) of the Historical Energy Cost Period, then either the Staff or the Company may propose an interim revision to the then currently effective Energy Cost Rate.

This Space For PSC Use Only

Agers, Donna

From: Kim Imhof [KImhof@empiredistrict.com]
Sent: Friday, December 08, 2006 4:55 PM
To: Agers, Donna
Cc: Bill Eichman
Subject: FW: Empire District (Arkansas) - ECR Factors

Sensitivity: Confidential

Donna,

Below are the ECR rates for 10/05 - 3/07. We file on April 1 each year. The annual filing reflects the fuel costs for the previous calendar year. We are allowed interim filings if various criteria are met, the first filed in October 2005. If you need anything further please let me know.

ENERGY COST RECOVERY
ARKANSAS

From	To	ECR Amount
10-1-05	3-31-06	$0.035365
4-1-06	3-31-07	$0.037657

Thanks,
Kim Imhof
Regulatory Analyst
Empire District Electric Co
417-625-6545

-----Original Message-----
From: Bill Eichman
Sent: Friday, December 08, 2006 2:23 PM
To: Kim Imhof
Subject: FW: Empire District (Arkansas) - ECR Factors
Sensitivity: Confidential

-----Original Message-----
From: Agers, Donna [mailto:dagers@consultbai.com]
Sent: Friday, December 08, 2006 10:22 AM
To: Bill Eichman
Subject: RE: Empire District (Arkansas) - ECR Factors
Sensitivity: Confidential

Bill,

I should have also asked for April 2006 as well.

Thank you for your help. Happy holidays!

Donna

> -----Original Message-----

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No.: 9.1	Docket No.: 99-249-U
Replacing: Original	Sheet No.: 9.1	Order No.: 15
		Effective: 3/9/01

Entergy Arkansas, Inc.
Name of Company

Kind of Service: Electric Class of Service: Commercial/Industrial

Part III. Rate Schedule No.: 9

Title: Large Power Service - Time-Of-Use (PST)

PSC File Mark Only

9.0. LARGE POWER SERVICE - TIME-OF-USE

9.1. APPLICABLE SERVICE AREA (AT)

In the Distribution Service area allocated by the Arkansas Public Service Commission ("APSC" or the "Commission") to Entergy Arkansas, Inc. ("EAI" or the "Company"), at any point on Company's existing facilities having adequate capacity and suitable voltage for delivery of service. This schedule may also apply outside the Company's allocated Distribution Service area to customers who have been released to EAI by other electric distribution utilities, when such release for service has been approved by the Commission pursuant to Rule 7.04.(b) of the Commission's Rules of Practice and Procedure. This schedule is also subject to the jurisdiction of the Tennessee Regulatory Authority where applicable.

9.2. AVAILABILITY

To all electric service required by any Customer with maximum demand of 1,000 kW or greater on the premises, when supplied at one point of delivery and measured through one meter. Applicable to standby or supplementary service and to interruptible service only in conjunction with the applicable Rider for such service. Not applicable to resale or shared service.

9.3. CHARACTER OF SERVICE

Single- or three-phase, 60 cycles and at one standard delivery voltage required by Customer and available at Customer's service location where service is delivered and metered at voltages less than 13,800Y/7,960. For service delivered and/or metered at other voltages, see Rate Schedule No. 18 for the appropriate adjustments to the Net Monthly Rate.

9.4. NET MONTHLY RATE (AT, MT)

This rate shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws.

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No.: 9.2	Docket No.: 99-249-U
Replacing: Original	Sheet No.: 9.2	Order No.: 15
		Effective: 3/9/01

Entergy Arkansas, Inc.
Name of Company

Kind of Service: Electric Class of Service: Commercial/Industrial

Part III. Rate Schedule No.: 9

Title: Large Power Service - Time-Of-Use (PST)

PSC File Mark Only

9.4.1. Rate

(AT)

Function: / Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Customer Charge:			$344.45	$24.43	$368.88
Demand Charge per kW:					
Summer Period*					
All On-Peak kW	$9.36	$0.83	$1.93	$0.00	$12.12
All Excess kW	$2.88	$0.25	$0.60	$0.00	$3.73
Other Period*					
All On-Peak kW	$7.92	$0.70	$1.63	$0.00	$10.25
All Excess kW	$2.53	$0.22	$0.52	$0.00	$3.27
Demand Credit per kW Per Settlement Agreement in APSC Docket No. 96-360-U:					
Maximum kW:	$(0.25)	$0.00	$0.00	$0.00	$(0.25)
Energy Charge per kWh:					
Summer Period*					
All On-Peak kWh	1.089¢	0.096¢	0.225¢	0.000¢	1.410¢
All Off-Peak kWh	0.777¢	0.069¢	0.160¢	0.000¢	1.006¢
Other Period*					
All On-Peak kWh	0.599¢	0.053¢	0.124¢	0.000¢	0.776¢
All Off-Peak kWh	0.514¢	0.045¢	0.106¢	0.000¢	0.665¢

*Summer Period is defined as the billing months of June, July, August and September. All other billing months are defined as "Other Period."

9.4.2. On-Peak Hours

Summer Period:	Other Period
1:00 p.m. - 8:00 p.m.	7:00 a.m. - 6:00 p.m.
Monday - Friday	Monday - Friday

9.4.3. Off-Peak Hours

All hours not designated as on-peak hours.

9.4.4. Minimum

Function: / Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Customer Charge:			$344.45	$24.43	$368.88
Demand Charge per kW: Highest kW established in the twelve months ending with the current month:	$1.44	$0.13	$0.64	$0.00	$2.21

Energy Cost Recovery factor times the energy consumed as reduced by Rate Schedule No. 18, if applicable.

If the calculated amount from paragraph 9.4.4. above is greater than the calculated amount from paragraph 9.4.1. above plus all Adjustments from paragraph 9.4.5. below, the minimum bill will be the calculated amount from paragraph 9.4.4. above.

9.4.5. Adjustments

Applicable Riders which adjust this Rate Schedule are listed in Rate Schedule No. 17, Table of Riders Applicable to Rate Schedules.

9.5. DEMAND

The kW or kVA, if kVA metered, as shown by or computed from the readings of the Company's demand meter, for the 15-minute period of greatest use during the month, subject to the following:

1. If kVA metered: Billing kW = Metered kVA x 0.9
2. If kW metered: Billing kW = Metered kW
3. In either case the Billing kW will not be less than 1,000 kW of on-peak demand

Excess Demand is the amount by which Off-Peak Demand exceeds On-Peak Demand.

9.6. PAYMENT

The monthly bill shall be computed in accordance with the Net Monthly Rate, other provisions of the rate schedule and all applicable riders. Payment shall be made in accordance with Rate Schedule No. 29, Charges Related to Customer Activity (CAC), paragraph 29.18.1. (RT,AT) (RT,AT) (AT)

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.: 9.4	Docket No.: 99-249-U Order No.: 15 Effective: 3/9/01
Replacing:	Sheet No.:	
Entergy Arkansas, Inc. Name of Company		
Kind of Service: Electric	Class of Service: Commercial/Industrial	
Part III. Rate Schedule No.: 9		
Title: Large Power Service - Time-Of-Use (PST)		PSC File Mark Only

9.7. CONTRACT PERIOD (MT)

Not less than five years.

No term contract will be required for Customer who, through Federal Statute, rule or regulation, is prohibited from entering into Company's standard Agreement for Electric Service and who meets the Company's requirements for advancing the cost of connection facilities.

9.8. SERVICE REGULATIONS (MT, RT)

Service under this schedule is subject to Policy Schedule No. 9, Service Regulations, of the Company as it is now on file, and as it may in the future be filed, with the APSC and the rules of the Commission.

41.0. OPTIONAL INTERRUPTIBLE SERVICE RIDER

41.1. AVAILABILITY

Available upon installation of the appropriate metering and communications equipment to any customer receiving service under the Small General Service, Large General Service, Large Power Service, Large General Service Time-of-Use or Large Power Service Time-of-Use Rate Schedules that is willing to contract for and use interruptible power and energy from Entergy Arkansas, Inc. ("EAI" or the "Company") during On-Peak Hours. Interruptible Power shall be no less than 100 kW. This Rider shall be in effect from its effective date only until such time that retail competition for electric generation is in effect in EAI's service territory.

41.2. DEFINITIONS

41.2.1. FIRM CONTRACT DEMAND

Firm Contract Demand is the demand (kW) that the Customer intends to exclude from interruptions. The Firm Contract Demand shall be specified in the Customer's Agreement for Interruptible Service. The Customer may change its Firm Contract Demand once during the Contract Period upon giving 60 days written notice to the Company.

41.2.2. NONFIRM ENERGY

For Small General Service Customers, the monthly Nonfirm Energy shall be determined by comparing the monthly billing demand, including any modifications pursuant to Section 41.5.6., to the recorded interval data on an interval by interval basis for the current month. The billing demand will be subtracted from the recorded demand by interval and summed for the billing period to determine Nonfirm Energy. Nonfirm energy shall not be less than zero (0) in any interval.

41.2.3. NONFIRM DEMAND

41.2.3.1. For Large General Service Time-of-Use and Large Power Service Time-of-Use Customers, the monthly Nonfirm Demand shall be the difference between the monthly on-peak billing demand including any modifications pursuant to Section 41.5.5. and the maximum demand registered for the current month, but not less than zero (0).

41.2.3.2. For Large General Service and Large Power Service Customers, the monthly Nonfirm Demand shall be the difference between the monthly billing demand including any modifications pursuant to Section 41.5.6. and the maximum demand registered for the current month, but not less than zero (0).

41.2.4. RESTRICTED HOURS

Restricted hours are those hours for which the Customer has been notified in accordance with Section 41.3. to take only its Firm Contract Demand.

41.2.5. PEAK LOAD CONDITIONS

Peak Load Conditions are defined as those conditions on any day that could result in the Entergy System establishing a monthly peak.

41.2.6. CAPACITY SHORTAGE CONDITIONS

Capacity Shortage Conditions are defined as those conditions on any day in which the Company has insufficient generating resources, including firm purchases, capable of supplying its load requirements within EAI's service area.

41.2.7. SUMMER MONTHS

The Summer Months are June, July, August, and September.

41.2.8. OTHER MONTHS

Other months are January, February, March, April, May, October, November, and December.

41.2.9. ON-PEAK HOURS

Summer Months	Other Months
1:00 p.m. – 8:00 p.m.	7:00 a.m. – 6:00 p.m.
Monday – Friday	Monday – Friday

ARKANSAS PUBLIC SERVICE COMMISSION

Original	Sheet No.: 41.3	Docket No.: 96-360-U
		Order No.: 39
Replacing:	Sheet No.:	Effective: 6/24/99
Entergy Arkansas, Inc. Name of Company		
Kind of Service: Electric	Class of Service: Commercial/Industrial	
Part III. Rate Schedule No.: 41		
Title: Optional Interruptible Service Rider (OIS)		PSC File Mark Only

41.3. NOTIFICATION PROVISIONS

The Company will notify the Customer or designated representative of the Customer via a mutually acceptable method by 4:30 p.m. that on the following day the Company may call for interruption ("Day-Ahead Notice"). The Day-Ahead Notice will provide an estimated starting time. Actual interruption should occur within four hours of that estimated starting time. The Day-Ahead Notice shall also be counted towards any interruption limits found in Section 41.4.1. For such maximum limits on hours, if no actual interruption is called for on the day following the Day-Ahead Notice, hours of interruption shall be imputed as an amount equal to the amount in the "Hours Per Interruption" column for that month in Section 41.4.1. On the day following the Day-Ahead Notice, if the Company is expecting a Peak Load Condition, is experiencing a Capacity Shortage Condition, or is experiencing an emergency condition, the Company may call for an interruption of the Customer's demand in excess of the Firm Contract Demand during the On-Peak Hours by providing thirty minutes advance notice via a mutually acceptable method. The thirty-minute advance notice shall specify the starting time of the interruption period.

41.4. MAXIMUM INTERRUPTIONS

41.4.1. The maximum hours per interruption are as follows:

Season	Days Per Month	Interruptions Per Day	Hours Per Interruption	Hours Per Month
Summer Months	10	1	4	35
Other Months	10	2	3	55

41.4.2. The Company shall not discriminate among Customers taking service under this Rider and shall use its best reasonable efforts to interrupt Customers taking service under this Rider on an equal basis.

41.4.3. Curtailments imposed in accordance with Policy Schedule No. 10 and service interruptions due to damage or failure of transmission or distribution equipment shall not be considered interruption periods for the purpose of this Rider.

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No.: 41.4	Docket No.: 99-249-U
		Order No.: 15
Replacing: Original	Sheet No.: 41.4	Effective: 3/9/01

Entergy Arkansas, Inc.
Name of Company

Kind of Service: Electric Class of Service: Commercial/Industrial

Part III. Rate Schedule No.: 41

Title: Optional Interruptible Service Rider (OIS)

PSC File Mark Only

41.5. BILLING PROVISIONS

(AT)

41.5.1. Monthly Customer Charge:

Function: / Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Monthly Customer Charge additional to Customer Charge under applicable standard rate schedule:	$0.00	$0.00	$77.19	$72.81	$150.00

41.5.2. Except as provided in Section 41.5.5. for Large General Service Time-of-Use and Large Power Service Time-of-Use Customers, the monthly on-peak billing demand will be the demand as registered for the current month during the On-Peak Hours, but no more than the Firm Contract Demand, and the off-peak billing demand will be the maximum demand as registered during the current month.

41.5.3. Except as provided in Section 41.5.6. for Small General Service, Large General Service and Large Power Service Customers, the monthly billing demand will be the maximum demand as registered for the current month, but no more than the Firm Contract Demand.

41.5.4. Any other provisions of the Company's tariffs to the contrary notwithstanding, the demand or energy rates under Rate Schedules 37 and 42 for Nonfirm demand or energy of Customers taking service under this Rate Schedule shall be 51.6% of the otherwise applicable rate.

41.5.5. If, for any reason, a Large General Service Time-of-Use or Large Power Service Time-of-Use Customer does not reduce demand during the Restricted Hours in accordance with Section 41.3. the monthly on-peak billing demand for the first such occurrence during that month will be the Firm Contract Demand plus 1.5 times the amount by which the highest demand established during the Restricted Hours in the current month exceeded the Firm Contract Demand. For each subsequent failure, the 1.5 multiplier will be increased by 0.5 but the resultant multiplier will not exceed a value of 5.0 in any month.

41.5.6. If, for any reason, a Small General Service, Large General Service or Large Power Service Customer does not reduce demand during the Restricted Hours in accordance with Section 41.3. the monthly billing demand for the first such occurrence during that month will be the Firm Contract Demand plus 1.5 times the amount by which the highest demand established during the Restricted Hours in the current month exceeded the Firm Contract Demand. For each subsequent failure, the 1.5 multiplier will be increased by 0.5 but the resultant multiplier will not exceed a value of 5.0 in any month. (MT)

41.5.7. Monthly minimum demand charge: (AT)

Function: / Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Monthly Minimum Demand Charge per kW: Applied to the lesser of the highest total demand established after the effective date of the Agreement for Interruptible Service or the Firm Contract Demand:	$1.38	$0.13	$0.62	$0.15	$2.28

41.6. CONTRACT PERIOD

The Agreement for Interruptible Service shall be for a minimum period of one year and a maximum of five years at the Customer's option, and shall be automatically renewed for successive terms equal in length to the initial term until terminated by advance written notice from Customer no less than three months prior to any anniversary date. Notwithstanding the above, if this Rider is terminated pursuant to Section 41.1., the Agreement for Interruptible Service shall concurrently be terminated. Any provision of the Company's tariffs to the contrary notwithstanding, a Customer that changes Rate Schedules concurrently with initiating Optional Interruptible Service shall not be required to contract for service under the new Rate Schedule for a period exceeding one year.

41.7. OTHER PROVISION

Except as modified herein, all provisions of the applicable Rate Schedules will apply.

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No.: 18.1	Docket No.: 99-249-U
		Order No.: 15
Replacing: Original	Sheet No.: 18.1	Effective: 3/9/01
Entergy Arkansas, Inc. Name of Company		
Kind of Service: Electric	Class of Service: Commercial/Industrial	
Part IV. Rate Schedule No.: 18		
Title: Voltage Adjustment Rider (M1)		PSC File Mark Only

18.0. VOLTAGE ADJUSTMENT RIDER

18.1. AVAILABILITY

Available at the option of the Company to a customer receiving electric service under any approved Small General Service, Large General Service, or Large Power Service Rate Schedules where such service is delivered and/or metered at voltages of 13,800Y/7,960 or greater. Does not apply to Minimum provision of any Rate Schedule.

18.2. ADJUSTMENT TO NET MONTHLY RATE

This rate shall remain in effect until modified or terminated in accordance with its terms or applicable regulations or laws. (AT)

18.2.1. Service is delivered and metered at voltages less than 13,800Y/7,960.

No reduction in Demand or Energy.

18.2.2. Service is delivered at voltages less than 13,800Y/7,960 but metering is at voltages 13,800Y/7,960 or greater but less than 115,000 Volts.

Reduce Demand and Energy by 1% for losses.

18.2.3. Service is metered at voltages less than 13,800Y/7,960 and Customer owns and maintains all transformation facilities. (AT)

Function: Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Reduce Monthly Demand Charge per kW by:	$0.00	$0.00	$0.77	$0.00	$0.77
Reduce Daily Demand Charge per kW, if applicable, by:	$0.0000	$0.0000	$0.0253	$0.0000	$0.0253

18.2.4. Service is delivered and metered at voltages of 13,800Y/7,960 or greater but less than 115,000 Volts and Customer owns and maintains all transformation facilities. (AT)

Function: Billing Item	Generation	Transmission	Distribution	Customer Service	Total
Reduce Demand and Energy by 1.0% for losses; and,					
Reduce Monthly Demand Charge per kW by:	$0.00	$0.00	$0.77	$0.00	$0.77
Reduce Daily Demand Charge per kW, if applicable, by:	$0.0000	$0.0000	$0.0253	$0.0000	$0.0253

ARKANSAS PUBLIC SERVICE COMMISSION

1st Revised	Sheet No.: 18.2	Docket No.: 99-249-U
Replacing: Original	Sheet No.: 18.2	Order No.: 15
		Effective: 3/9/01

Entergy Arkansas, Inc.
Name of Company

Kind of Service: Electric Class of Service: Commercial/Industrial

Part IV. Rate Schedule No.: 18

Title: Voltage Adjustment Rider (M1)

PSC File Mark Only

18.2.5. Service is delivered at 115,000 Volts or greater but metered at a lower voltage. (AT, MT)

Function:	Generation	Transmission	Distribution	Customer Service	Total
Billing Item					
Reduce Demand and Energy by 1.0% for losses; and, Reduce Monthly Demand Charge per kW by:	$0.00	$0.00	$1.63	$0.00	$1.63
Reduce Daily Demand Charge per kW, if applicable, by:	$0.0000	$0.0000	$0.0536	$0.0000	$0.0536 (AT)

18.2.6. Service is delivered and metered at 115,000 Volts or greater.

Function:	Generation	Transmission	Distribution	Customer Service	Total
Billing Item					
Reduce Demand and Energy by 2.0% for losses; and, Reduce Monthly Demand Charge per kW by:	$0.00	$0.00	$1.63	$0.00	$1.63
Reduce Daily Demand Charge per kW, if applicable, by:	$0.0000	$0.0000	$0.0536	$0.0000	$0.0536

37.0. ANO DECOMMISSIONING COST RIDER

37.1. APPLICATION

The Rider is applicable to all electric service billed under the rate schedules designated in Attachment A to the Rider, whether metered or unmetered, and subject to the jurisdiction of the Arkansas Public Service Commission (APSC).

This rider will become effective for service rendered on and after March 23, 1988 or on the date approved by the APSC, whichever is later.

37.2. CONDITIONS

37.2.1. This rider is necessary in order to collect the decommissioning costs associated with EAI's Arkansas Nuclear One nuclear generating station (ANO).

37.2.2. The Net Monthly Rates in EAI's currently effective rate schedules will be increased by the Rate Adjustment amounts set forth in Attachment A to this Rider, which shall apply during the period indicated thereon. The Rate Adjustment amounts shall be revised annually pursuant to the procedures described in Paragraphs 37.2.4. and 37.2.5. below.

37.2.3. Funding Method

A. EAI shall establish external trusts to accumulate the necessary funds to decommission ANO.

B. EAI shall place the maximum possible amount of its internally funded decommissioning reserve balance associated with each ANO unit into an external tax-qualified trust established for each ANO unit pursuant to the laws and Internal Revenue Service regulations in effect at that time. EAI shall place any remaining balance of its internally funded ANO decommissioning balance, net of the associated accumulated deferred tax balance, into an external trust that is not tax-qualified.

C. EAI shall then deposit all future revenues collected under this Rider, net of uncollectible accounts and any applicable taxes, to the tax-qualified trusts described in 37.2.3.B. above up to amounts equal to the maximum allowable deduction in any year. Any remaining amount not eligible for the tax-qualified trusts shall be deposited to the external trusts that are not tax-qualified. A transfer of funds shall be made once each month on or before the tenth day of the month to include all revenue billed to customers under this Rate Schedule No. 37 during the second preceding month net of an allowance for uncollectible accounts to be determined by multiplying the

uncollectible account ratio for each class as approved in EAI's most recent general rate filing by the revenue amount for each class.

37.2.4. Annual Revision

A. EAI shall determine revised Rate Adjustment amounts annually in accordance with the provisions of Paragraph 37.2.5. below and file a revised Attachment A containing such revised Rate Adjustment amounts with the Commission on or before November 1 of each year.

B. The Commission Staff shall then have until December 15 to review each annual revision of Attachment A to insure that it complies with the requirements of Paragraph 37.2.5. below. If any errors are detected in the application of the principles contained in Paragraph 37.2.5., they shall be communicated to EAI by the Commission Staff in writing on or before December 15. EAI shall then have until December 31 to prepare and file a corrected Attachment A with the Commission.

C. The initially filed Rate Adjustment amounts or such corrected Rate Adjustments as may be determined pursuant to the terms of Paragraph 37.2.4.B. above shall then become effective for service on and after the following January 1 and shall remain in effect through December 31 of the following year.

37.2.5. Revenue Requirement and Rate Determination

A. The ANO decommissioning revenue requirement for the Arkansas retail jurisdiction that is to be utilized to develop the Rate Adjustment amounts in Attachment A for each calendar year shall be determined in accordance with the ANO Decommissioning Revenue Requirement Model approved by the Commission in its Order No. 5 in Docket No. 87-166-TF.

The Rate Adjustment amounts to be set out in each revision to Attachment A shall reflect the most currently available estimates of the following input data items:

1. Trust Management Fee Rates for ANO-1 and ANO-2
2. Composite State and Federal Income Tax Rate
3. Arkansas Retail Bad Debt Rate
4. Tax Qualified Trust Earnings Rate Projections
5. Non-Tax Qualified Trust Earnings Rate Projections
6. Percentage of Collections Eligible for transfer to Tax Qualified Trust (ANO-1 and ANO-2)

7. Projections of Annual Decommissioning Expenditures for ANO-1 and ANO-2

8. Projection of Annual Consumer Price Index - Urban

9. The trust fund balances at December 31 of the year in which the update is filed.

The revised Rate Adjustments shall be based on the revenue requirements for the coming calendar year.

B. The Arkansas jurisdictional revenue requirement determined for each calendar year in accordance with Paragraph 37.2.5.A. above shall be allocated to the same rate classes and in the same proportions as the Arkansas retail revenue requirement in EAI's most recent general rate filing in which a final order has been issued and which has resulted in non-appealable rates.

C. The Rate Adjustments for each rate class shall be determined by dividing the rate class revenue requirements determined in accordance with Paragraph 37.2.5.B. above by the projected class billing units for the calendar year in which the revised Rate Adjustments will be in effect.

Order No.: 44
Effective: January 2006

Attachment A to
Rate Schedule No. 37
Page 1 of 1

ATTACHMENT A

The Net Monthly Rates set forth in EAI's schedules identified below will be increased by the following Rate Adjustments amounts during the billing months of January 2006 through December 2006:

Rate Class	Rate Schedules	Rate Adjustment
ANO-1		
Residential	RS, RT	$0.00000 per kWh
Small General Service	SGS, GFS, MP, AP, CTV, M14, CGS	$0.00000 per kWh
Large General Service	LGS, GST, LPS, PST	$0.00 per kW
Lighting	L1, L2, L4	$0.00000 per kWh
ANO-2		
Residential	RS, RT	$0.00000 per kWh
Small General Service	SGS, GFS, MP, AP, CTV, M14, CGS	$0.00000 per kWh
Large General Service	LGS, GST, LPS, PST	$0.00 per kW
Lighting	L1, L2, L4	$0.00000 per kWh

42.0. GRAND GULF RIDER

42.1. APPLICATION

To all electric service billed under any rate schedule, whether metered or unmetered, subject to the jurisdiction of the Arkansas Public Service Commission ("APSC").

42.2. CONDITIONS

In Opinion No. 234 in Docket ER82-616-000 and Docket ER82-483-000 the Federal Energy Regulatory Commission ("FERC") allocated to Entergy Arkansas, Inc. ("EAI" or "Company") 36% of the power from the 90% share of Grand Gulf Unit 1 nuclear generating unit owned by System Energy Resources, Inc. ("SERI"). Entergy Arkansas became responsible for paying SERI for the Grand Gulf power commencing with delivery on July 1, 1985. All costs associated with Grand Gulf Unit 1 incurred by EAI will be retained or recovered by the Company from its Arkansas retail customers in accordance with the Stipulation and Settlement Agreement approved by the APSC in APSC Docket No. 84-249-U as amended ("Stipulation and Settlement Agreement"). (CT,RT)

The cost of this power will be allocated in the following manner beginning January 1, 1994 and all succeeding years:

	Percent of SERI's Share of Grand Gulf Unit 1	Company Allocation Share of Grand Gulf Unit 1 Costs
Current Recovery Share	28.08%	78.00%
Retained Share	7.92%	22.00%
	36.00%	100.00%

(RT)

The energy related portion of Grand Gulf costs associated with the Current Recovery Share and the energy from the Retained Share which is sold to the Company's Arkansas retail customers pursuant to the Stipulation and Settlement Agreement will be recovered under Energy Cost Recovery Rider ECR as purchased power. (CT,RT)

ARKANSAS PUBLIC SERVICE COMMISSION

7th Revised	Sheet No.: 42.2	
Replacing: 6th Revised	Sheet No.: 42.2	
Entergy Arkansas, Inc. Name of Company		
Kind of Service: Electric	Class of Service: All	Docket No.: 05-126-TF Order No.: 1 Effective: January 2006
Part III. Rate Schedule No.: 42		
Title: Grand Gulf Rider (M33)		PSC File Mark Only

The Net Monthly Rates for Grand Gulf demand related costs for the billing period from January 2006 through December 2006 will be as follows: (CT)

Rate Class	Rate Schedules	Net Monthly Rate	
Residential	RS, RT	$0.00743 per kWh	(CR)
Small General Service	SGS, GFS, MP, AP, CTV, M14, CGS	$0.00586 per kWh	(CR)
Large General Service	LGS, GST, LPS, PST	$2.07 per kW	(CR)
Lighting	LI, L2, L4	$0.00948 per kWh	(CR)

42.3. PROCEDURES FOR RECOVERY OF GRAND GULF COSTS

42.3.1. On or before November 1 of 1998 and each succeeding year thereafter, the Company will file with the APSC a revision to this Grand Gulf Rider which will reflect the demand related Grand Gulf costs which are projected to be incurred over the twelve-month period beginning on January 1 of the following year and will also file new Net Monthly Rates necessary to recover such costs to become effective on the first billing cycle of January of such year. These new Net Monthly Rates will reflect a true-up of any prior over or under recovery of such costs as determined in Paragraph 42.3.6. below. In the revision to this Grand Gulf Rider (M33) filed with the APSC, the 36% allocation to EAI will be further allocated based on the percentages embodied in the Stipulation and Settlement Agreement as the Current Recovery Share and the Retained Share.

42.3.2. The Current Recovery Share allocated to the Company's Arkansas retail customers will be recovered on a current basis.

42.3.3. The Grand Gulf demand related costs will be reduced to reflect reserve equalization receipts, if any, which may be associated with the Company's allocation of Grand Gulf capacity. The total annual Grand Gulf costs to be recovered from the Company's Arkansas retail customers under this Grand Gulf Rider will be allocated to the Arkansas retail jurisdiction using the production demand related allocation methodology approved or utilized in the Company's most recent retail rate case. Beginning January 1, 1998, and until changed by the Commission, this factor is 86.13 percent. (MT)

42.3.4. The total annual Grand Gulf costs for the retail classes will be allocated to the associated retail rate classes on the basis of the level of revenue requirements approved in the most recent Arkansas retail rate case. (MT)

42.3.5. A. For those retail rate classes consisting of customers with maximum demands generally below 100 kW, the Grand Gulf demand related costs as allocated under Paragraph 42.3.4. above will be recovered through an energy rate adder determined by dividing such allocated costs by the forecasted sales for each rate class for the next twelve months.

B. For the remaining retail rate classes, the Grand Gulf demand related costs as allocated in Paragraph 42.3.4. above will be recovered through a demand rate adder determined by dividing such allocated costs by the forecasted demand billing units for each rate class for the next twelve months.

42.3.6. At the end of each twelve months, the actual recovery of Grand Gulf demand related costs under this Grand Gulf Rider will be compared to the actual cost incurred by the Company for Grand Gulf demand related costs allocable to Arkansas retail customers to determine the net over or under recovery. The net over or under recovery so determined shall be subtracted from or added to the determination of the annual Grand Gulf demand related costs to be recovered as specified in Paragraph 42.3.1. above for the following 12-month period. The actual costs as defined above will be allocated to Arkansas retail customers using the Production Demand allocation factor in effect on January 1 of the prior year.

42.3.7. Should any conflict or inconsistency arise between the terms of this Grand Gulf Rider and the terms of the Stipulation and Settlement Agreement referenced above, the terms of the Stipulation and Settlement Agreement shall control.

ARKANSAS PUBLIC SERVICE COMMISSION

Original Sheet No. 42.4

Replacing 1st Revised Sheet No. 121

Entergy Arkansas, Inc.
Name of Company

Kind of Service: Electric Class of Service: All

Part III. Rate Schedule No.: 42

Title: Grand Gulf Rider (M33)

Docket No.: 98-312-TF
Order No.: 1
Effective: 1/1/99

PSC File Mark Only

(MT)

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ENTERGY ARKANSAS, INC.

ARKANSAS RETAIL
ENERGY COST RECOVERY and
FUEL & PURCHASED POWER COST FACTORS

Billing Month	$ Per kWh
2003	
Jan - Mar	$ 0.00892 per kWh
Apr - Dec	$ 0.00896 per kWh
2004	
Jan - Mar	$ 0.00896 per kWh
Apr - Dec	$ 0.01039 per kWh
2005	
Jan - Mar	$ 0.01039 per kWh
Apr - Sep	$ 0.01365 per kWh
Oct - Dec	$ 0.01900 per kWh
2006	
Jan - Mar	$ 0.01900 per kWh
Apr - Jun	$ 0.01900 per kWh
Jul - Dec	$ 0.02827 per kWh
2007	
Jan - Mar	$ 0.02827 per kWh

ELECTRIC SERVICE TARIFF:

POWER AND LIGHT LARGE SCHEDULE: "PLL-4"

GEORGIA POWER
A SOUTHERN COMPANY

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AVAILABILITY:

Throughout the Company's service area from existing lines of adequate capacity.

APPLICABILITY:

To all electric service of one standard voltage required on the customer's premises, delivered at one point and metered at or compensated to that voltage for any customer with a demand, as determined under the Special Applicability Provisions, of 500 kW or greater.

TYPE OF SERVICE:

Single or three phase, 60 hertz, at a standard voltage.

MONTHLY RATE:

Residential Energy Charge Including Demand Charge:

Base Charge.....$17.00

All consumption (kWh) not greater than 200 hours times the billing demand:

First 3,000 kWh	**@**	**10.738¢ per kWh**
Next 7,000 kWh	**@**	**9.766¢ per kWh**
Next 190,000 kWh	**@**	**8.358¢ per kWh**
Over 200,000 kWh	**@**	**6.476¢ per kWh**

All consumption (kWh) in excess of 200 hours and not greater than 400 hours times the billing demand **@** **1.106¢ per kWh**

All consumption (kWh) in excess of 400 hours and not greater than 600 hours times the billing demand **@** **0.874¢ per kWh**

All consumption (kWh) in excess of 600 hours times the billing demand **@** **0.632¢ per kWh**

Minimum Monthly Bill:

A. **$17.00 Base Charge plus $7.78 per kW of billing demand, plus excess kVAR charges and Fuel Cost Recovery as applied to the current month kWh.**

B. **Metered Outdoor Lighting: The lesser of (1) that determined from paragraph "A" above, or (2) $38.60 per meter plus Fuel Cost Recovery for metered outdoor lighting installations, provided service is limited to the lighting equipment itself and such incidental load as may be required to operate coincidentally with the lighting equipment.**

SCHEDULE: "PLL-4"

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Commercial Energy Charge Including Demand Charge:

Base Charge $17.00

All consumption (kWh) not greater than 200 hours times the billing demand:

First 3,000 kWh	@	10.897¢ per kWh
Next 7,000 kWh	@	9.874¢ per kWh
Next 190,000 kWh	@	8.443¢ per kWh
Over 200,000 kWh	@	6.549¢ per kWh

All consumption (kWh) in excess of 200 hours and not greater than 400 hours times the billing demand ..... @ ..... 1.117¢ per kWh

All consumption (kWh) in excess of 400 hours and not greater than 600 hours times the billing demand ..... @ ..... 0.883¢ per kWh

All consumption (kWh) in excess of 600 hours times the billing demand ..... @ ..... 0.638¢ per kWh

Minimum Monthly Bill:

A. $17.00 Base Charge plus $7.82 per kW of billing demand, plus excess kVAR charges and Fuel Cost Recovery as applied to the current month kWh.

B. Metered Outdoor Lighting: The lesser of (1) that determined from paragraph "A" above, or (2) $38.99 per meter plus Fuel Cost Recovery for metered outdoor lighting installations, provided service is limited to the lighting equipment itself and such incidental load as may be required to operate coincidentally with the lighting equipment.

Industrial Energy Charge Including Demand Charge:

Base Charge $17.00

All consumption (kWh) not greater than 200 hours times the billing demand:

First 3,000 kWh	@	11.199¢ per kWh
Next 7,000 kWh	@	10.164¢ per kWh
Next 190,000 kWh	@	8.647¢ per kWh
Over 200,000 kWh	@	6.710¢ per kWh

All consumption (kWh) in excess of 200 hours and not greater than 400 hours times the billing demand ..... @ ..... 1.143¢ per kWh

All consumption (kWh) in excess of 400 hours and not greater than 600 hours times the billing demand ..... @ ..... 0.904¢ per kWh

All consumption (kWh) in excess of 600 hours times the billing demand ..... @ ..... 0.653¢ per kWh

Minimum Monthly Bill:

A. $17.00 Base Charge plus $8.05 per kW of billing demand, plus excess kVAR charges and Fuel Cost Recovery as applied to the current month kWh.

B. Metered Outdoor Lighting: The lesser of (1) that determined from paragraph "A" above, or (2) $39.91 per meter plus Fuel Cost Recovery for metered outdoor lighting installations, provided service is limited to the lighting equipment itself and such incidental load as may be required to operate coincidentally with the lighting equipment.

SCHEDULE: "PLL-4"

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DETERMINATION OF REACTIVE DEMAND:

Where there is an indication of a power factor of less than Ninety-Five percent (95%) lagging, the Company may at its option, install metering equipment to measure Reactive Demand. The Reactive Demand shall be the highest 30-minute kVAR measured during the month. The Excess Reactive Demand shall be kVAR which is in excess of one-third of the measured actual kW in the current month. The Company will bill excess kVAR at the rate of $0.27 per excess kVAR.

FUEL COST RECOVERY:

The amount calculated at the above rate will be increased under the provisions of the Company's effective Fuel Cost Recovery Schedule, including any applicable adjustments.

DETERMINATION OF BILLING DEMAND:

The Billing Demand shall be based on the highest 30-minute kW measurement during the current month and the preceding eleven (11) months.

For the billing months of **June** through **September**, the Billing Demand shall be the greatest of:

(1) The current actual demand, or
(2) Ninety-Five percent (95%) of the highest actual demand occurring in any previous applicable summer month (June through September), or
(3) Sixty percent (60%) of the highest actual demand occurring in any previous applicable winter month (October through May).

For the billing months of **October** through **May**, the Billing Demand shall be the greater of:

(1) Ninety-Five percent (95%) of the highest summer month (June through September), or
(2) Sixty percent (60%) of the highest winter month (October through May), including the current month.

In no case shall the Billing Demand be less than the greatest of:

(1) The contract minimum, or
(2) Fifty percent (50%) of the total contract capacity, or
(3) 500 kW.

SPECIAL APPLICABILITY PROVISIONS:

Limitation of Service

Service will be provided hereunder for those customers having a calculated demand of 500 kW or greater where that calculation is the greater of:

(1) Applying Sixty percent (60%) to the current or previous Eleven (11) months winter or off-peak demands, or
(2) Applying Ninety-Five percent (95%) to the current or previous Eleven (11) months summer or on-peak demands.

For customers on the Off-Peak (OP) and Variable Off-Peak (VOP) riders the demand shall be based on the percentages as stated in the riders.

Construction Service

Construction power shall be considered as a part of permanent service and will be provided in accordance with the Applicability section of this schedule. The Company will obtain a payment in advance for each metering point to be served in the amount currently on file with the Georgia Public Service Commission.

TERM OF CONTRACT:

Five (5) years.

SCHEDULE: "PLL-4"

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GENERAL TERMS & CONDITIONS:

The bill calculated under this tariff is subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission under the provisions of applicable riders.

Service hereunder subject to Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.

ELECTRIC SERVICE TARIFF:

Demand Plus Energy Credit Rider
SCHEDULE: "DPEC-1"

GEORGIA POWER
A SOUTHERN COMPANY

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AVAILABILITY:

Throughout the Company's service area from existing lines of adequate capacity.

APPLICABILITY:

This rider is applicable to any customer who chooses, upon request, to provide at least 200 kW of demand reduction FPA Part 1 customers are not eligible for this Rider.

TYPE OF SERVICE:

Three phase, 60 hertz, at a standard voltage.

DESCRIPTION:

This tariff allows customers to participate in credits for demand reduction. Customers will receive credits in exchange for reducing electric demand during periods in which the Company is experiencing extreme supply and demand conditions. The customer will reduce demand during a specified time period, and the company will credit the customer's electric bill for the demand reduction. There will be a minimum notice of 30 minutes for demand reductions.

DEMAND REDUCTION AND CREDITS:

Maximum Hours/Year	Energy Credit Rate	Demand Credit Rate
100	1.00 $/kWh	6.25 $/kW
50	1.00 $/kWh	4.75 $/kW
25	.50 $/kWh	3.50 $/kW

A monthly energy credit will be paid in each billing month which includes a reduction period. The demand credit will be paid in each of the four summer billing months of June through September.

The customer and the Company will agree on the customer's Firm Demand Level (FDL) in kilowatts. The customer must reduce demand to the FDL or lower during all reduction periods.

At the end of each billing month which includes a reduction period, the Company will calculate a monthly energy credit.

> The monthly energy credit will equal the product of the energy credit rate and the monthly actual energy (kWhs) reduced below the Normal Electric Demand (NED), excluding energy reduced below the FDL.

At the end of each summer billing month, the Company will calculate a monthly demand credit.

> The monthly demand credit will equal the product of the demand credit rate and the actual demand reduction. The actual demand reduction will equal the difference in the Normal Electric Demand (NED) and the FDL during the DPEC Peak Period.

Special Provisions for Customers on all RTP tariffs: The FDL must be lower than the CBL. The NED is calculated based on the CBL.

SCHEDULE: "DPEC-1"

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NORMAL ELECTRIC DEMAND:

During each of the summer billing months of June through September, the monthly NED is the customer's actual, average demand during non-holiday weekdays, excluding days in which there was a demand reduction, from 12:00 noon to 8:00 p.m.

During each of the winter billing months of October through May, the monthly NED is the customer's actual, average demand during non-holiday weekdays, excluding days in which there was a demand reduction, over all hours of the day.

DPEC PEAK PERIOD:

The DPEC peak period during the summer months of June through September is non-holiday weekdays, from 12:00 noon to 8:00 p.m.

COMPLIANCE INCENTIVE:

If the customer's actual metered demand during a reduction period is greater than the FDL, the customer will be charged a compliance incentive of $3.50 per kW for each kW above the FDL during each hour of the reduction period. The maximum compliance incentive is forfeiture of the demand credit plus $9.00 per kW of annual actual demand reduction and applies to the October through September period.

The annual actual demand reduction will equal the difference in the annual Normal Electric Demand (NED) and the FDL during the DPEC Peak Period. The annual NED is the customer's actual, average demand during the DPEC Peak Period, excluding days in which there was a demand reduction.

No compliance incentive will be charged for the first two 30-minute intervals of non-compliance per year (October through September).

If necessary, a monthly compliance incentive will be charged up to the amount of the monthly demand credit. A settlement of the customer's total annual compliance incentive will be completed at the end of the October through September period, and additional charges up to the annual maximum will be billed at that time, if necessary.

ADMINISTRATIVE CHARGE:

$120.00 per month. If additional metering equipment is required, the equipment and its installation must be paid for by the customer in addition to the administrative charge.

LIMITS ON DEMAND REDUCTION:

Maximum Hours of Demand Reduction per Day: 8

TERM OF CONTRACT:

The contract term is one year. The customer is required to remain on the DPEC tariff for a period of twelve months from the contract date. The contract will be automatically renewed on the anniversary date of the contract for an additional year, unless terminated with 30 days' written notice to the Company.

SCHEDULE: "DPEC-1"

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PENALTY FOR CONTRACT TERMINATION:

The customer may terminate his contract at any time by informing Georgia Power Company and living out the remaining portion of his contract, or a customer may terminate his contract and pay one of the following amounts:

1 year or more notice:	No penalty.
Less than 1 year's notice:	Penalty equals the demand credit received in the previous year plus forfeiture of the demand credit in the current year.

For customers that terminate their electric service contract and permanently close their operations, the Penalty for Contract Termination may be waived and credit payments suspended, at the sole discretion of the company.

GENERAL TERMS & CONDITIONS:

The credit calculated under this Rider is subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission under the provisions of applicable riders.

Service hereunder subject to Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.

ELECTRIC SERVICE TARIFF:

FUEL COST RECOVERY SCHEDULE: "FCR-18"

GEORGIA POWER
A SOUTHERN COMPANY

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1 of 2	With Bills Rendered for the Billing Month of July 2006	Original	9.00

AVAILABILITY:

Available to all customers in Georgia Power Company's service area as it existed on June 30, 2006.

APPLICABILITY:

This schedule is applicable to and becomes a part of each retail rate schedule in which reference is made to the Fuel Cost Recovery Schedule.

RATE:

All bills rendered subject to the Fuel Cost Recovery Schedule shall be respectively increased in an amount equal to:

Secondary Distribution customers .....3.0248¢ per kWh
Primary Distribution customers .....2.9767¢ per kWh
Transmission customers .....2.9389¢ per kWh

Fuel Costs shall be the cost of:

(1) fossil, nuclear, bio-mass (including renewable) fuel and emission allowances consumed in the Company's own plants, and the Company's share of fossil, nuclear, and bio-mass (including renewable) fuel and emission allowances consumed in jointly owned or leased plants; plus

(2) the identifiable fossil, nuclear, bio-mass (including renewable) fuel and emission allowance costs associated with energy purchased for reasons other than identified in (3) below; plus

(3) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost of energy; less

(4) the cost of fossil, nuclear, bio-mass (including renewable) fuel and emission allowances recovered through intersystem sales when sold on an economic dispatch basis; less

(5) retail portion of gains resulting from the sale of any emissions allowances; less

(6) seventy-five percent of net gains from wholesale market opportunity sales; plus or minus

ELECTRIC SERVICE TARIFF:

FUEL COST RECOVERY SCHEDULE: "FCR-17"

GEORGIA POWER
A SOUTHERN COMPANY

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1 of 2	With Bills Rendered for the Billing Month of June 2005	Original	9.00

AVAILABILITY:

This schedule is applicable to and becomes a part of each retail rate schedule in which reference is made to the Fuel Cost Recovery Schedule.

RATE:

All bills rendered subject to the Fuel Cost Recovery Schedule shall be respectively increased in an amount equal to:

Secondary Distribution customers .....2.4581¢ per kWh
Primary Distribution customers .....2.4190¢ per kWh
Transmission customers .....2.3883¢ per kWh

Fuel Costs shall be the cost of:

(1) fossil, nuclear, bio-mass (including renewable) fuel and emission allowances consumed in the Company's own plants, and the Company's share of fossil, nuclear, and bio-mass (including renewable) fuel and emission allowances consumed in jointly owned or leased plants; plus

(2) the identifiable fossil, nuclear, bio-mass (including renewable) fuel and emission allowance costs associated with energy purchased for reasons other than identified in (3) below; plus

(3) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for energy purchases and the charges as a result of scheduled outages, all such kinds of energy being purchased by the buyer to substitute for its own higher cost of energy; less

(4) the cost of fossil, nuclear, bio-mass (including renewable) fuel and emission allowances recovered through intersystem sales when sold on an economic dispatch basis; less

(5) retail portion of gains resulting from the sale of any emissions allowances; less

(6) seventy-five percent of net gains from wholesale market opportunity sales; plus or minus

(7) net gains and losses incurred under the Natural Gas and Oil Procurement and Hedging Program implemented in Docket No. 16134-U; plus or minus

(8) carrying costs on over or under recovered fuel balance calculated at the Company's short-term debt rate and excluding the first $15 million of any under recovered cost; plus or minus

(9) other costs or credits as determined by the Commission for inclusion in, or reduction of, recoverable fuel costs.

ELECTRIC SERVICE TARIFF:

MERGER TRANSITION CREDIT SCHEDULE: "MTC-1"

GEORGIA POWER
A SOUTHERN COMPANY

PAGE	EFFECTIVE DATE	REVISION	PAGE NO
1 of 1	With Bills Rendered for the Billing Month of July, 2006	Original	9.15

AVAILABILITY:

Available to all customers in Georgia Power Company's service area as it existed on June 30, 2006.

APPLICABILITY:

The MTC will be applied to all customers in the Georgia Power territory as it existed on June 30, 2006 and will be designed to distribute all amounts collected by the MTA to customers in the Georgia Power territory as it existed on June 30, 2006 on a per kWh basis; provided, however, that the MTC shall not apply to RTP customers above their respective CBL since the MTC is designed to compensate customers for the higher fuel charges resulting from the merger and, for usage above their CBL, these customers are not paying such higher fuel charges.

RATE:

All bills rendered subject to this rider will be decreased in an amount equal to 0.1204¢ per kWh.

TERM OF CONTRACT:

This rider will expire on December 31, 2007 or as soon thereafter as appropriate to zero the accounts.

GENERAL TERMS & CONDITIONS

The adjustment calculated under this rider is subject to change in such an amount as may be approved and/or amended by the Georgia Public Service Commission.

Service hereunder subject to Rules and Regulations for Electric Service on file with the Georgia Public Service Commission.