Cover Page for Schedule MEB-2

Market-Based Rate Schedules		
Section	**Utility**	**Rate Schedule**
1	Omaha Public Power District	Rate 261M – Large Power – High Voltage Transmission Level – Market Energy
2	Nevada Power Company d/b/a NV Energy	Schedule LCMPE – Large Customer Market Price Energy
3	Public Service Company of New Mexico	Special Service Rate – Renewable Energy Resources
4	Virginia Electric and Power Company	Schedule MBR – Large General Service Market-Based Rates
5	Northern Indiana Public Service Company	Rate 831 – Rate for Electric Service, Industrial Power Service – Large
6	Alliant Energy	Day Ahead Market Pricing Rider

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OPPD
Omaha Public Power District

What is Rate 261M?

OPPD's Board of Directors unanimously approved Rate 261M in January 2017. This rate is an extension of Rate 261 for large-power, high-voltage-transmission-level customers, and is a unique and powerful example of how OPPD works to meet their needs, particularly those who seek more renewable energy.

Rate 261M gives customers flexibility in how they meet their energy goals, while charging fair and reasonable rates that cover OPPD's fixed costs, including generation and system capacity, transmission and administration.

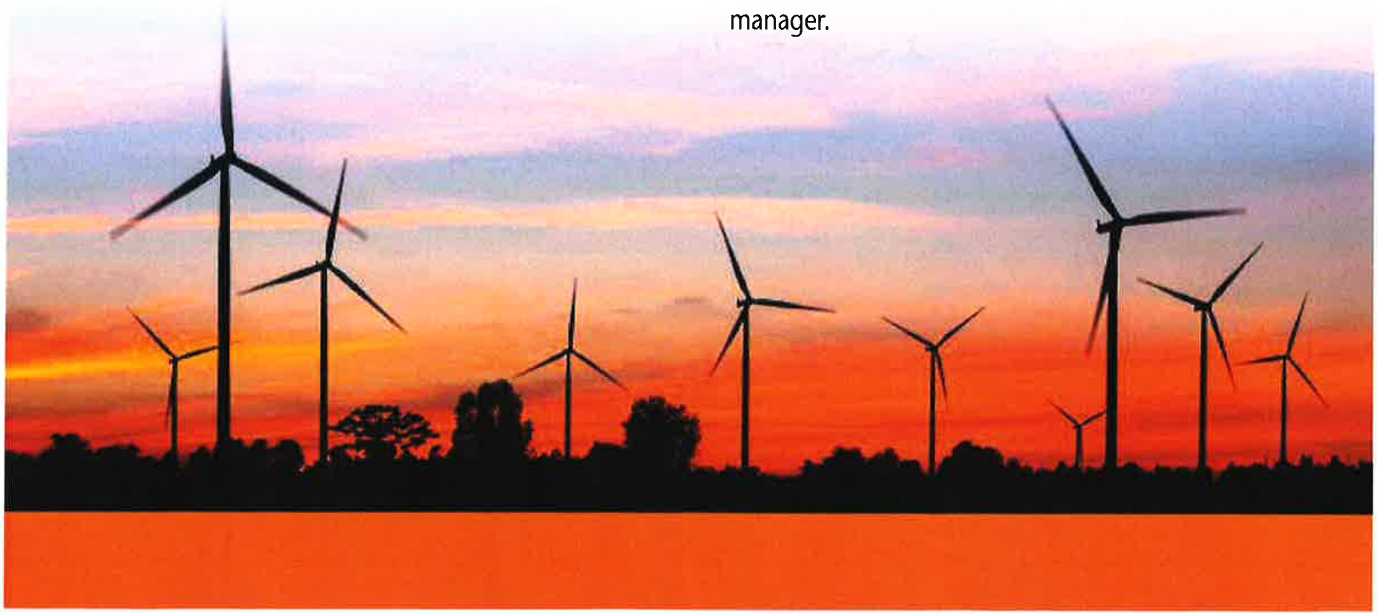
The rate was the result of hard work across a number of areas within OPPD. The team carefully evaluated existing rates to see where slight modifications could be made to accommodate the demands of new and existing customers' desires for large-scale renewables.

Rate 261M is an example of the agility of the public power model when it comes to finding solutions for customers, while bringing economic development benefits to the area.

Here's how it works:

- To qualify for Rate 261M, a customer must be large enough to meet certain criteria, such as requiring a minimum 20 megawatts (MW) of demand for 161-kilovolt (kV) service and 200 MW of demand for 345-kV service. A ramp-up period of 18 months is allowed before that minimum usage requirement kicks in.
- The customer must own or acquire their own substation.
- Energy is priced hourly at the Southwest Power Pool market price. A customer's renewable project is also based on SPP marketing pricing, creating a pricing hedge.
- OPPD provides retail service to the customer, including generation and system capacity, transmission and administration.

Potential new customers who want to learn more should contact **Tim O'Brien**, manager- Economic Development, *trobrien@oppd.com* or call 402-636-3731. Current OPPD customers should contact their account manager.



Return to Rates and Riders List

RATE SCHEDULE NO. 261M

Large Power – High-Voltage Transmission Level – Market Energy

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as three-phase service will be supplied radially from OPPD's system at a nominal standard voltage of 161,000 volts or 345,000 volts, where the Customer owns its electric substation for the delivery of the service.

The minimum Demand for service under this Rate Schedule is 20,000 kilowatts for service at 161,000 volts or a minimum Demand of 200,000 kilowatts for service at 345,000 volts each month.

Customers must substantiate to OPPD's satisfaction that their Demand requirements will meet the minimum Demand requirements of this Rate Schedule within 18 months of establishing service under this Rate Schedule.

The Customer's high voltage Electric Service will be measured by one Demand Meter, unless a Customer takes emergency or special service as required by OPPD's Service Regulations.

BILLING COMPONENTS

Monthly Service Charge: $10,000.00 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$22.45

Minimum Billing Demand of 20,000 kilowatts per month for interconnection at 161,000 volts, or 200,000 kilowatts per month for interconnection at 345,000 volts.

Energy Charge

An Energy Charge will be assessed based on the number of kilowatt-hours consumed in any given hour multiplied by the appropriate cost to purchase energy from the Southwest Power Pool (SPP) for that hour. OPPD will notify the Customer of the SPP node used to price the hourly energy and all applicable SPP charges. The billing notice will be enforceable under this Rate Schedule and OPPD's Service Regulations.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill: $459,000.00 for Customers taking service at 161,000 volts

or

$4,500,000.00 for Customers taking service at 345,000 volts

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirement of $449,000 for interconnection at 161,000 volts, or 200,000 kilowatt minimum Demand requirement of $4,490,000 for interconnection at 345,000 volts, plus the monthly service charge of $10,000. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period during the initial 18 months of service, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's greatest use during the same billing period.

For billing period of 18 months or after the initial service date, Demand will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of Customer's highest use during the same billing period.

If after month 17 of the initial service date, the Demand is less than 95% leading or lagging of the Customer's highest 15-minute kilovolt ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 95% of the kilovolt ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 90% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 75% of the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 20,000 kilowatts for Customers receiving service at 161,000 volts

  or

  200,000 kilowatts for Customers receiving service at 345,000 volts

ADMINISTRATIVE

Special Conditions

Customers taking service under this Rate Schedule must provide written notice twelve (12) months before switching between the Market Energy Base Option and the Non-Market Energy Base Option.

Customers taking service under this Rate Schedule will be required to execute and comply with operational policies and any other requirements as determined by OPPD.

OPPD assumes no liability for Customer-owned facilities.

OPPD will determine the Point(s) of Delivery using the information provided by the Customer regarding the Customer's requirements. The Point of Delivery will be based on the needs and requirements of OPPD's systems and facilities.

Due to the nature of service provided under this Rate Schedule, OPPD and the Customer will jointly agree upon a metering point that adequately and safely meets OPPD's requirements. If OPPD determines it is necessary to place Meters in a location away from the Point of Delivery, OPPD reserves the right to adjust its Meter readings and billings to account for delivery line losses.

Customers receiving service from more than one high voltage transmission source are restricted from tying or paralleling the sources at any time or for any duration. All transfers between sources must be performed as open transition transfers.

For planning purposes, the Customer will notify OPPD of their expected monthly Demand (in kilowatts) at least one week before the start of each month. In the event the Customer's actual monthly Demand varies by five (5) or more megawatts, OPPD reserves the right to request more frequent notifications regarding expected Loading conditions.

Under OPPD's Service Regulations, the resale, redistribution, marketing or extension of Electric Service received by the Customer, including in any wholesale or other markets, is prohibited. Customers are prohibited from taking wholesale transmission services to serve their Demand.

Customers served under this Rate Schedule shall not export power on OPPD's electrical system.

Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

Schedule No. LCMPE
LARGE CUSTOMER MARKET PRICE ENERGY

APPLICABLE

This large customer market price energy rate schedule is applicable to all non-Residential Service Customers demonstrating that they will have an average annual hourly load of ten megawatts or more, are not a fully bundled retail customer of the Utility, and have not been approved by the PUCN to purchase energy, capacity and ancillary services from a provider of new electric resource under NRS Chapter 704B; or have been approved by the PUCN to purchase energy, capacity and ancillary services from a new provider of new electric resource under NRS Chapter 704B, have an average annual hourly load of ten megawatts or more, and have paid in full any impact fee the PUCN assessed pursuant to provisions of NRS Chapter 704B. (D, T) (N) (N)

TERRITORY

Entire Nevada service territory, as specified.

RATES

A. A Customer receiving service under this schedule that has not yet achieved the ten megawatt load threshold, based upon an average monthly hourly usage, shall take service under the otherwise applicable rate schedule until such time that the ten megawatt threshold has been achieved.

B. A Customer receiving service under this schedule that has achieved the ten megawatt load threshold will pay the following rates and charges:

1. The BTGR of the otherwise applicable rate schedule of the Customer, with the cost of generation capacity and energy supply removed through bill credits.
2. A demand charge, if applicable, under the otherwise applicable rate schedule.
3. A facilities charge, if applicable, under the otherwise applicable rate schedule.
4. The BSC of the otherwise applicable rate schedule.
5. The UEC as described in Special Condition 1.
6. Franchise Fees, Taxes and Mill Assessment that are assessed under the otherwise applicable rate schedule.

(Continued)

Issued: **06-16-21**	Issued By:	
Effective: **06-29-21**	John P. McGinley	
Advice No.: **513**	Vice President, Regulatory	

Schedule No. LCMPE
LARGE CUSTOMER MARKET PRICE ENERGY
(Continued)

RATES (continued)

7. Public Program Costs unless exempted by any applicable law or order of the PUCN.

8. An energy charge as specified in an Energy Supply Agreement between the Utility and the Customer. (D,T) (T)

C. A Customer receiving service under this schedule that has achieved the ten megawatt load threshold will not pay the following rates and charges:

1. A Customer taking service under this schedule shall not be subject to the Net-BTER, DEAA.

D. Unless otherwise described in the Energy Supply Agreement, a Customer receiving service under this schedule that subsequently falls below the ten megawatt threshold, based on a twelve-month rolling average, shall pay the otherwise applicable rate schedule of the Customer until the Customer's twelve-month rolling average once again achieves a ten megawatt load threshold. (T)

SPECIAL CONDITIONS

1. **UEC.** The Universal Energy Charge (UEC), pursuant to NAC 702.150 through 702.450, will go to fund the Nevada fund for energy assistance and conservation. Under certain circumstances, Customers will be refunded amounts paid in excess of $25,000 per calendar quarter. The Commission will administer the collection of the UEC, certify exemptions, and administer refunds. Exemptions are generally kWh sold to:
   a) Any governmental agency, including the State of Nevada and any political subdivision thereof, and
   b) Any Customer using electrolytic-manufacturing processes.

Except as provided above, all kWh sold are subject to the charge. The UEC is not subject to the charges applicable under the Special Supplementary Tariff.

2. **Rights and Obligations.** The rights and obligations of the parties with respect to the supply of energy will be specified in an Energy Supply Agreement. (D,T)

(Continued)

Schedule No. LCMPE
LARGE CUSTOMER MARKET PRICE ENERGY
(Continued)

(N)

SPECIAL CONDITIONS (continued)

3. **Energy Supply Agreement.** The Energy Supply Agreement must be approved by the Commission. In considering whether the Energy Supply Agreement is in the public interest, the Commission will consider whether non-participating customers of the utility experience increased costs for electric service or forgo the benefit of a reduction of costs for electric service as a result of the Energy Supply Agreement.

   The Energy Supply Agreement shall:
   a. Be in the public interest;
   b. Provide for payment by the Customer of the Utility's cost in procuring the energy for the Customer;
   c. Provide for a payment by the Customer for its portion of the Utility's transmission and distribution costs;
   d. Not impair the reliability of the Utility's system or the Utility's ability to provide electric service to its other customers;
   e. Include other terms and conditions related to the respective rights and obligations of the Utility and Customer to take service under this schedule;
   f. Identify the basis for the calculation of the price of energy;
   g. Be the same term as the underlying renewable resource unless otherwise specified and explained in the Energy Supply Agreement.

4. **Termination.** The termination rights of the Customer and the Utility are governed by the terms of the applicable Energy Supply Agreement.

5. **RPS Compliance.** For every Customer that takes service under this schedule, the Utility shall retire or transfer to the Customer to retire portfolio energy credits in compliance with the RPS. The Utility shall retain the difference between the amount of portfolio energy credits procured pursuant to the Energy Supply Agreement and the RPS, unless as specified otherwise under the terms and conditions of the Energy Supply Agreement between the Customer and the Utility.

DEFINITIONS

For purposes of this Schedule No. LCMPE, the following definitions apply.

A. BSC: The Basic Service Charge, which is approved by the Commission.

B. BTER: A rate consisting of the base tariff energy rate which is approved by the Commission.

(N)

(Continued)

(N)

Schedule No. LCMPE
LARGE CUSTOMER MARKET PRICE ENERGY
(Continued)

DEFINITIONS (Continued)

C. BTGR: A rate consisting of the base tariff general rate which is approved by the Commission.

D. DEAA: A rate consisting of the deferred energy accounting adjustment, which is approved by the Commission.

E. Energy resources: energy used to supply the Customer with energy pursuant to the terms of the Energy Supply Agreement, including market purchases made on behalf of the eligible customer, and energy from the Utility's other generation and purchased power that was not procured on behalf of the eligible customer, but is available to be sold into the market.

F. Energy Supply Agreement: Is the contract approved by the Commission that is executed by the Customer and Utility pursuant to terms of Schedule No. LCMPE.

G. Net-BTER: A rate consisting of the BTER less the cost of the out-of-the-money long-term renewable energy contracts that the Utility has entered into.

H. Public Program Costs: Are all costs that the Utility incurs in implementing legislatively-mandated programs.

I. PUCN: Is the Public Utilities Commission of Nevada.

J. Renewable Energy: As defined in NRS 704.7811, Renewable Energy means biomass, geothermal, solar, waterpower, and wind.

K. RPS: As defined in NRS 704.7805, Portfolio Standard means a portfolio standard for Renewable Energy and energy from a qualified energy recovery process established by the Commission pursuant to NRS 704.7821. The Portfolio Standard provides for increasing minimum amounts of Renewable Energy to be added annually to the Utility's mix of resources required to meet its load requirements.

L. UEC: A rate consisting of the universal energy charge, which is approved by the Commission.

(N)

(Continued)

PUBLIC SERVICE COMPANY OF NEW MEXICO
ELECTRIC SERVICES

3RD REVISED RATE NO. 36B
CANCELING 2ND REVISED RATE NO. 36B

SPECIAL SERVICE RATE – RENEWABLE ENERGY RESOURCES

EXPLANATION OF RATE: This Special Service Rate, the companion Green Energy Rider (Rider No. 47) and the companion Production Cost Allocation Rider (Rider No. 49) are available to eligible customers who wish to have the Company acquire renewable energy resources in an amount equal to some or all of the customer's electric utility service requirements and who enter into a Special Service Contract, approved by the New Mexico Public Regulation Commission ("NMPRC"), that establishes the rates and other terms and conditions for such service. Rates covering the full cost of the renewable energy resources shall be established in the Special Service Contract pursuant to the Green Energy Rider. This Special Service Rate, along with the Production Cost Allocation Rider, prescribes the methodology that the Company and the customer will use in the Special Service Contract to establish all other charges to be paid by the customer for electric service. If the electric service requested by the customer requires the Company to extend or upgrade its transmission or other facilities, the cost of the extension or upgrade shall be paid by the customer to the extent consistent with generally accepted regulatory principles of cost causation, and shall be included in the rates set in the Special Service Contract, with adequate provisions to secure the customer's payment obligation.

Except as provided in the Special Service Contract, service will be furnished subject to the Company's Rules and Regulations and any subsequent revisions. These Rules and Regulations are available at the Company's office and are on file with the NMPRC. These Rules and Regulations are a part of this Schedule as if fully written herein.

TERRITORY: All territory served by the Company in New Mexico.

CUSTOMER ELIGIBILITY: To be eligible for this Special Service Rate, a customer must meet all of the following conditions:

1) As of the date of commercial operation, the customer must not have previously received electric utility service from the Company.
2) The customer must enter into a Special Service Contract with the Company for a term that is coextensive with the customer's payment obligation for the renewable resources, and the NMPRC must approve the contract.
3) The customer must achieve a minimum demand of 10,000 kW.
4) The customer must achieve a load factor of at least 75%.
5) The customer must cause the addition of renewable resources of 10,000 kW-A/C or more to be acquired by the Company.
6) The customer must meet all of the requirements of the Company's Green Energy Rider (Rider No. 47).

TYPE OF SERVICE: Three-phase service delivered at the Company's available transmission voltage of 115 kV or higher.

SUBSTATION EQUIPMENT: All substation and distribution transformers, the necessary structures, voltage regulating devices, lightning arrestors, and accessory equipment required by the customer in order to utilize the Company's service at 115 kV or higher voltage shall be installed, paid for, owned, operated, and maintained by the customer.

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BY Comm. Final Order Case# 16-00276-UT

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Mark A. Fenton
Director, Regulatory Policy and Case Management
GCG#525237

The customer shall also provide at its expense suitable protective equipment and devices so as to protect the Company's system and service and other electric users from disturbances or faults that may occur on the customer's system or equipment.

The customer shall at all times keep each of the three phases balanced as far as practicable so as not to affect service and voltage to other customers served by the Company. The customer shall not operate any equipment in a manner which will cause voltage disturbances elsewhere on the Company's system.

NET RATE PER MONTH OR PART THEREOF FOR EACH SERVICE LOCATION: The rate for electric service provided shall be the sum of A, B, C, D, E, F, G and H below. On-Peak period is from 8:00am to 8:00pm Monday through Friday (60 hours per week). Off-Peak period is all times other than the On-Peak period (108 hours per week).

(A) CUSTOMER CHARGE:

All Months: $3,705.85 per bill X

(B) TRANSMISSION DEMAND CHARGE:

All months: $3.90 per Billable On-Peak kW X

(C) ENERGY CHARGE FOR SYSTEM SUPPLIED ENERGY:
During each hour when the energy from the renewable energy resources acquired by PNM to meet all or part of the customer's load is less than the customer's hourly usage, the balance of hourly energy will be supplied by other energy resources available to PNM for overall system needs. For all hourly energy supplied by PNM's other energy resources, the customer will pay the fuel rates under the Company's Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") applicable to transmission voltage customers.

(D) ENERGY RELATED NON-FUEL CHARGE FOR SYSTEM SUPPLIED ENERGY:
During each hour when the energy from the renewable energy resources acquired by PNM to meet all or part of the customer's load is less than the customer's hourly usage, the balance of hourly energy will be supplied by other energy resources available to PNM for overall system needs. For all hourly energy supplied by PNM's traditional energy resources, the following energy related non-fuel charge is applicable.

Energy Related Non-Fuel Charge: $0.0056917 per kWh X

(E) CONTRIBUTION TO PRODUCTION COMPONENT:
During each hour when the energy from the renewable energy resources acquired by PNM to meet all or part of the customer's load is less than the customer's hourly usage, the balance of hourly energy will be supplied by other energy resources available to PNM for overall system needs. For all hourly energy supplied by PNM's traditional energy resources,

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the customer shall pay a contribution to production charge. The rate is described in the customer's Special Service Contract and may be fixed for a period of time as provided in that contract. Following the Company's next general rate case, this initial contribution to production component will be superseded by a demand-based Contribution to Production Component, as defined in the Special Service Contract, that will recover allocated production costs.

All months: $xxx per Billable On-Peak kW

(F) GREEN ENERGY RIDER CHARGE:
Pursuant to the Green Energy Rider No. 47, the customer will be responsible for all costs associated with the renewable energy resources acquired to meet all or part of the customer's load.

(G) OTHER APPLICABLE RIDERS:
Rider No. 36 – Renewable Energy Rider, and all other applicable rate riders shall be billed to the customer in accordance with the terms of the riders, and consistent with applicable statutes and NMPRC rules. Rider No. 16 -- the Energy Efficiency Rider shall not be applicable.

(H) SPECIAL TAX AND ASSESSMENT ADJUSTMENT:
Billings under this Schedule may be increased by an amount equal to the sum of the taxes payable under the Gross Receipts and Compensating Tax Act and of all other taxes, fees, or charges (exclusive of ad valorem, state and federal income taxes) payable by the Company and levied or assessed by any governmental authority on the public utility service rendered, or on the right or privilege of rendering the service, or on any object or event incidental to the rendition of the service.

DETERMINATION OF MONTHLY ON-PEAK BILLABLE DEMAND: The monthly on-peak billable demand shall be as determined by appropriate measurement as defined by the Company, but in no event shall it be less than the highest of the following: (a) the actual highest On-Peak metered demand registered during the current month, or (b) 10,000 kW. The On-Peak period is from 8:00am to 8:00pm Monday through Friday (60 hours per week). The Off-Peak period is all times other than the On-Peak period (108 hours per week).

INTERRUPTION OF SERVICE: The Company will use reasonable diligence to furnish a regular and uninterrupted supply of energy. However, interruptions or partial interruptions may occur or service may be curtailed, become irregular, or fail as a result of circumstances beyond the control of the Company, or are the results of acts of public enemies, accidents, strikes, legal processes, governmental restrictions, fuel shortages, breakdown or damages to generation, transmission, or distribution facilities of the Company, repairs or changes in the Company's generation, transmission, or distribution facilities, and in any such case the Company will not be liable for damages. Customers whose reliability requirements exceed these normally provided should advise the Company and contract for additional facilities and increased reliability as may be

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required. The Company will not, under any circumstances, contract to provide 100 percent reliability.

ACCESSIBILITY: Equipment used to provide electric service must be physically accessible. The metering must be installed on each service location at a point accessible to Company personnel at any time.

TERMS OF PAYMENT: All bills are net and payable within twenty (20) days from the date of bill. If payment for any or all electric service rendered is not made within thirty (30) days from the date the bill is rendered, the Company shall apply an additional late payment charge as defined in Rate 16 Special Charges.

LIMITATION OF RATE: Electric service under this Schedule shall not be resold or shared with others.

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SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

I. APPLICABILITY AND AVAILABILITY

A. This Schedule is applicable on a voluntary basis only to a non-residential Customer (i) who elects to receive and who is receiving – as of the date of service for the Customer under this Schedule – Electricity Supply Service and Electric Delivery Service from the Company at the Customer's service location; and (ii) whose peak measured demand has reached or exceeded 5,000 kW at least once within the current and previous 11 billing months at the Customer's service location, and otherwise is eligible to purchase electric energy from any supplier of electric energy licensed to sell retail electric energy within the Commonwealth under Va. Code § 56-577 A 3.

B. This Schedule is available only after all of the following criteria are met:

1. The Company has installed metering equipment that it deems to be necessary to measure properly the Customer's demands and energy usage at the Customer's service location; and
2. If applicable, the Customer has installed and provided the Company with access to mutually agreed upon communication technology necessary for the Company to communicate with its metering equipment; and
3. The Customer has submitted to the Company an *Officer or Authorized Representative Acknowledgement Statement for Electric Service in Accordance with Rate Schedule MBR* ("Statement") which acknowledges that the Customer's representative who signs such Statement is a duly authorized officer or authorized representative and understands the terms and conditions under which the Customer will be billed in accordance with this Schedule;
4. The Company may require up to sixty (60) days after all of the criteria in Paragraph I.A. and Paragraph I.B., above, are met to provide service under this Schedule to the Customer at the Customer's service location.

C. Any Customer billed on the applicable of Schedule MBR – GS-3 – Large General Service, Secondary Voltage (Experimental) or Schedule MBR – GS-4 – Large General Service, Primary Voltage (Experimental) immediately prior to the effective date of this Schedule, may volunteer for this Schedule to become effective for billing to the Customer at the Customer's service location on or before April 13, 2020.

(Continued)

I. APPLICABILITY AND AVAILABILITY (Continued)

D. This Schedule is subject to an aggregate cap of 400 MW of participating Customer load. To determine whether a Customer can take service under this Schedule, the Company shall determine the aggregate load for both (i) the currently participating Customers on this Schedule and (ii) for any additional Customer requesting service under this Schedule. Such aggregate load shall be the sum of the loads for all such Customers (i.e., currently participating and additional Customers), based upon the higher of the Customers' (i) actual peak measured demands at their service locations, during the current and previous 11 billing months immediately prior to the date of service for the additional Customer under this Schedule or (ii) the anticipated kW demands in the Customers' load letters for their service locations, if applicable.

II. 30-DAY RATE

A. Distribution Service Charges

1. Basic Customer Charge

a. For Secondary Service Voltage
Basic Customer Charge $112.58 per billing month.

b. For Primary or Transmission Service Voltage
Basic Customer Charge $119.91 per billing month.

2. Plus Distribution Demand Charge

a. For Secondary Service Voltage
All kW of Distribution Demand @ $1.992 per kW

b. For Primary or Transmission Service Voltage
First 5000 kW of Distribution Demand @ $0.940 per kW
Additional kW of Distribution Demand @ $0.709 per kW

3. Plus rkVA Demand Charge @ $0.141 per rkVA

(Continued)

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

II. 30-DAY RATE (Continued)

4. Plus Distribution kWh Charges

a. Distribution kWh Charge for All Customers

1) For Secondary Service Voltage
All kWh @ 0.0066¢ per kWh

2) For Primary or Transmission Service Voltage
All kWh @ 0.0055¢ per kWh

b. Plus Distribution kWh Charge for Non-exempt or Non-opt-out Customers
All kWh @ 0.000¢ per kWh

5. Plus each Distribution kilowatt-hour used is subject to all applicable riders, included in the Exhibit of Applicable Riders.

B. Electricity Supply (ES) Service Charges

1. Market-based Rate Generation Charges

a. Generation Demand Charge
All kW of Generation Demand @ Generation Demand Billing Rate per kW

b. Plus Generation Energy Charge
All kWh @ Day-Ahead LMP per kWh

(The Generation Energy Charge in Paragraph II.B.1.b., above, is inclusive of all applicable charges (whether applied on a per-kWh or a per-kW basis in accordance with Paragraph X, below) for the fuel-related or generation-related Electricity Supply Service Riders, which are included in the Exhibit of Applicable Riders. Such fuel-related or generation-related Electricity Supply Service Rider Charges are not billed in addition to the Market-based Rate Generation Charges. This provision shall not apply to any Commission approved charges that are non-bypassable under Virginia law, unless the Customer meets the statutory requirements for exemption from such charges.)

(Continued)

II. 30-DAY RATE (Continued)

c. Plus PJM Ancillary Service Charges

Any reference to "PJM" in this Schedule means the PJM Interconnection, LLC (Pennsylvania-New Jersey-Maryland Interconnection, LLC), or any successor, that is the regional transmission organization and is part of the Eastern Interconnection grid that operates an electric transmission system. Any reference to "DOMLSE" in this Schedule means the Dominion Load Serving Entity, or any successor.

1) PJM Ancillary Service Charges for the current billing month, for which the Customer shall be charged, shall include all PJM ancillary service charges assigned to Customer's total monthly kWh energy consumption, which is grossed up for kWh losses (in accordance with the Schedule GS-3 Customer Class for secondary service voltage or the Schedule GS-4 Customer Class for primary or transmission service voltage and consistent with the level at which the PJM ancillary service charges have losses applied) and where such PJM ancillary service charges are not already included in this Schedule's Transmission Service Charges and Credits and Other Charges and Credits Recovered Pursuant to Va. Code § 56.585.1 A 4 ("A 4 Charges"). Currently, PJM Ancillary Service Charges include – but may not be limited now or in the future to – Day-Ahead and Balancing Operating Reserves, Day-Ahead Scheduling Reserves, Reactive Service and Reactive Supply & Voltage Control, Black Start and Regulation & Frequency Response, Synchronized Reserves, and Synchronous Condensing Charges. In the event of any future change in PJM's process for determining ancillary service charges, including any modification as to which ancillary services are included, this ancillary service charge shall represent the similar or like charges for ancillary service determined by PJM.

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

II. 30-DAY RATE (Continued)

2) For PJM Ancillary Service Charges, the Company will determine for the current billing month a monthly rate in $/kWh by taking such total monthly DOMLSE charges divided by total monthly DOMLSE kWh energy consumption (the "PJM Ancillary Service Charges Factor"). The Company will bill the PJM Ancillary Service Charges to the Customer based on the Customer's actual total monthly kWh energy consumption, grossed up for applicable Schedule GS-3 Customer Class kWh losses for secondary service voltage or Schedule GS-4 Customer Class kWh losses for primary or transmission service voltage, for the current billing month multiplied by the PJM Ancillary Service Charges Factor. The DOMLSE charges and total monthly DOMLSE kWh energy consumption represent those associated with the aggregation of the total jurisdiction and non-jurisdictional customers served by the Company in the Commonwealth of Virginia and the State of North Carolina.

d. Plus PJM Administrative Fees

1) PJM Administrative Fees for the current billing month shall include all PJM administrative fees assigned to Customer's total monthly kWh energy consumption, which is grossed up for kWh losses (in accordance with the Schedule GS-3 Customer Class for secondary service voltage or the Schedule GS-4 Customer Class for primary or transmission service voltage and consistent with the level at which the PJM ancillary service charges have losses applied), and where such PJM administrative fees are not already included in this Schedule's Transmission Service Charges and Credits and Other Charges and Credits Recovered Pursuant to Va. Code § 56.585.1 A 4 ("A 4 Charges"). In the event of any future change in PJM's process for determining administrative fees, including any modification as to what is being represented in the administrative fees, this PJM Administrative Fees charge shall represent the similar or like charges for administrative fees determined by the PJM.

(Continued)

II. 30-DAY RATE (Continued)

2) For PJM Administrative Fees, the Company will determine for the current billing month a monthly rate in $/kWh by taking such total monthly DOMLSE administrative fees divided by total monthly DOMLSE kWh energy consumption (the "PJM Administrative Fees Factor"). The Company will bill PJM Administrative Fees to the Customer based on the Customer's actual total monthly kWh energy consumption, grossed up for applicable Schedule GS-3 Customer Class kWh losses for secondary service voltage or Schedule GS-4 Customer Class kWh losses for primary or transmission service voltage, for the current billing month, multiplied by the PJM Administrative Fees Factor. The DOMLSE charges and total monthly DOMLSE kWh energy consumption represent those associated with the aggregation of the total jurisdiction and non-jurisdictional customers served by the Company in the Commonwealth of Virginia and the State of North Carolina.

3) In the event that PJM assigns any new or non-routine costs to the loads of the Company, which are not considered to be PJM Ancillary Services or PJM Administrative Fees, in the future for the Customer's total monthly kWh energy consumption, grossed up for applicable Schedule GS-3 Customer Class kWh losses for secondary service voltage or Schedule GS-4 Customer Class kWh losses for primary or transmission service voltage, during this Schedule's Term of Contract, pursuant to Paragraph XXIV., below, the Company and the Customer mutually agree that the Company shall bill and the Customer shall pay to the Company such new PJM costs. The Company shall include any and all such new PJM costs in with the PJM Administrative Fees as described in this Paragraph II.B.1.d., above.

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

II. 30-DAY RATE (Continued)

e. Plus Margin

1) The Customer shall pay to the Company a Margin for each kWh of Customer's total monthly energy consumption during the current billing month.

2) Such Margin for the current billing month shall be based on the Customer's Monthly Load Factor, which the Company will calculate in accordance with Paragraph XIII., below. The Customer's Monthly Load Factor at the Customer's service location shall determine the applicable Margin rate per kWh in accordance with the table below:

Customer's Monthly Load Factor	**Margin Rate per kWh**
>= 85%	$0.00085
< 85%	[$0.00085+ ((85 – Monthly Load Factor) * $0.00002)]

3) The Company shall disregard any Test Demand, as determined in Paragraph XVII., below, in calculating the Customer's Monthly Load Factor. In place of the Test Demand, the Company shall use the highest Non-Test Demand in the current billing month to determine the Customer's Monthly Load Factor.

2. Plus Transmission Service Charges and Credits and Other Charges and Credits Recovered Pursuant to Va. Code § 56.585.1 A 4 ("A 4 Charges")

a. All Monthly Demand-Related Transmission Service Charges and Credits shall be billed in accordance with the following:

Each kW of Customer's Network Service Peak Load shall be subject to all applicable transmission riders, included in the Exhibit of Applicable Riders.

b. Plus all Monthly Other A 4 Charges and Credits shall be billed in accordance with the following:

Each Electricity Supply kilowatt-hour used shall be subject to all applicable transmission riders, included in the Exhibit of Applicable Riders.

(Continued)

II. 30-DAY RATE (Continued)

C. The minimum charge shall be as may be contracted for in the Agreement for Electric Service (of which this Schedule is a part) executed by and between the Company and the Customer ("Agreement"). The minimum charges shall be (1) determined on a non-discriminatory, uniform basis for all customers receiving service under this Schedule under like conditions; and (ii) the minimum charge shall be designed to ensure that the Customer's billing supports the capacity level of the facilities required to provide Electric Service which are sized and installed by the Company at the Customer's service location based on information provided by the Customer; and (iii) the minimum charge shall be set at 50% of the lowest projected monthly billing amount less taxes, fuel and facilities charges (if applicable); and (iv) the minimum charge will only be applied when the Customer's monthly charges under this Schedule are insufficient to support the recovery of the costs associated with such Electric Service facilities; and (v) the minimum charge will terminate once the revenue (less taxes, fuel and facilities charges) collected from the customer exceeds the amount of credit a customer received against the initial estimated cost of distribution facilities constructed and sized to provide Electric Service to the customer. The customer has the option of making contributions outside of revenues from monthly bill payments in order to accelerate the termination of the minimum charge.

The Company shall have the discretion to implement a ramp-up period of up to four years for the minimum charge. This ramp-up period will be dependent of the load characteristics of the applicable customer.

III. DETERMINATION OF DISTRIBUTION DEMAND

A. The Distribution Demand shall be billed only where the normal service delivery voltage is less than 69 kV.

B. The Distribution Demand billed under the applicable of Paragraph II.A.2.a. or Paragraph II.A.2.b., above, shall be the higher of:

1. The highest average kW measured at the location during any 30-minute interval of the current and previous 11 billing months;
2. 500 kW;
3. The demand contracted for in the Agreement for Electric Service (of which this Schedule is a part) executed by and between the Company and the Customer, which shall be set at 70% of the customer's projected demand.

C. When the Customer's power factor at the Customer's service location is less than 85 percent, a minimum distribution demand of not less than 85 percent of the Customer's maximum kVA demand may be established.

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

IV. DETERMINATION OF rkVA DEMAND

The rkVA of demand billed under Paragraph II.A.3., above, shall be the highest average rkVA measured at the Customer's service location in any 30-minute interval during the current billing month.

V. EXEMPTION AND OPT-OUT PROVISIONS FOR DISTRIBUTION KWH CHARGE

The Distribution kWh Charge in Paragraph II.A.4.b., above, shall not apply to Customers who are either exempt from or opt-out of such charge pursuant to Virginia Code § 56-585.1 A 5 c.

VI. DETERMINATION OF GENERATION DEMAND

Any reference in this Schedule to the "Dominion Zone," or any successor, means PJM's load zone applicable to the DOMLSE and all other load serving entities currently included in the Dominion Zone ("DOM Zone").

A. The Generation Demand billed in Paragraph II.B.1.a., above, shall be determined in accordance with the following and shall be subject to adjustment for losses, PJM peak load units, PJM's zonal forecast peak load demand units, and reserves, as provided for, below:

B. Consistent with the PJM methodology, the average of the Customer's five (5) coincident peaks with PJM ("Average Customer 5CPs"), applicable to the Customer's service location, shall be grossed up using the following formula:

Generation Demand = 5CPs * L * WN* UCAP

Where:

5CPs = The Average Customer 5CPs, determined in accordance with Paragraph VI.B., above ("Customer's 5CPs");

L = The Company's average distribution and transmission loss adjustment factor ("Loss Factor") for providing capacity to serve the applicable of a Schedule GS-3 customer's load at secondary service voltage or a Schedule GS-4 customer's load for primary or transmission service voltage. The Loss Factor shall be calculated by the Company and updated annually. The Company multiplies the Customer's 5CPs by the Loss Factor to calculate the "Customer's 5CPs Grossed Up for Losses;"

(Continued)

VI. DETERMINATION OF GENERATION DEMAND (Continued)

WN = The scaling factor calculated by the electric distribution company ("EDC W/N Scaling Factor") that is used to adjust the Customer's 5CPs Grossed Up for Losses to the same level as the Dominion Zone Weather Normalized Coincident Peak Load ("Dominion Zone W/N Peak Load") for the DOMLSE. The EDC W/N Scaling Factor shall be calculated by the Company and updated annually. The Company multiplies the Customer's 5CPs Grossed Up for Losses by the EDC W/N Scaling Factor to calculate the Customer's "5CPs Adjusted for Losses and Weather Normalization;"

UCAP = The scaling factor calculated by the Company ("UCAP Obligation Scaling Factor") that is used to adjust the Customer's 5CPs Grossed Up for Losses and Weather Normalization to the same level as the Dominion Zone Updated Zonal Unrestricted Capacity Obligation ("Dominion Zone UCAP Obligation") for the DOMLSE. The UCAP Obligation Scaling Factor, which is based on PJM's 3rd Incremental Auction, shall be calculated by the Company and updated annually. The Company multiplies the Customer's 5CPs Grossed Up for Losses and Weather Normalization by the quotient of the Dominion Zone UCAP Obligation divided by the Dominion Zone W/N Peak Load.

This adjustment shall represent the Company's required capacity obligation based upon the volumes procured and/or assigned to the Company's load by PJM, as defined by the underlying PJM structure for acquiring capacity for load in PJM;

The Company shall use the PJM process, described above, to determine the Customer's Generation Demand applicable to the Customer's service location. In the event of any future change in PJM's process for determining the Dominion Zone UCAP Obligation, the Customer's Generation Demand shall represent the similar or like methodology used by PJM for determining the Dominion Zone UCAP Obligation. Similarly, in the event of any future change in the EDC methodology to determine a Customer's Generation Demand (e.g., utilization of 5CPs for peak load contribution) the Customer's Generation Demand shall represent the similar or like methodology used by the EDC for determining the Customer's Generation Demand.

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

VI. DETERMINATION OF GENERATION DEMAND (Continued)

C. If the Customer does not have 5CPs, the Customer's Generation Demand for the current billing month at the Customer's service location shall be the higher of the (i) highest average 30-minute demand measured by the Company during the on-peak hours or (ii) the highest average 30-minute demand measured by the Company during the off-peak hours grossed up accordingly as the 5CPs would be in Paragraph VI.B.

D. The kW of demand determined in accordance with the applicable of Paragraph VI.B. or Paragraph VI.C., above, shall be the Customer's Generation Demand at the Customer's service location ("Generation Demand").

VII. DETERMINATION OF GENERATION DEMAND BILLING RATE

The Generation Demand Billing Rate for the current billing month shall be equal to the PJM Final Zonal Net Load Price in $/MW-Day multiplied by the number of days in the current billing month and divided by 1,000 to convert $/MW to $/kW. The Generation Demand Billing Rate shall represent the price reflective of the cost to procure capacity in the PJM market to serve the Customer's Generation Demand. In the event of any future change in PJM's process for determining the price reflecting the cost to procure capacity for load in the PJM market to serve the Customer's Generation Demand, the Generation Demand Billing Rate shall represent the similar or like method used by PJM for determining the Generation Demand Billing Rate.

VIII. DETERMINATION OF GENERATION ENERGY

The Generation Energy billed in Paragraph II.B.1.b., above, shall be the Customer's monthly kWh energy consumption at the Customer's service location for the current billing month grossed up for the appropriate distribution losses for the applicable of a Schedule GS-3 customer for secondary service voltage or a Schedule GS-4 customer for primary or transmission service voltage.

IX. DETERMINATION OF DAY-AHEAD LMP

The Day-ahead LMP used to bill the Customer's Generation Energy in Paragraph II.B.1.b., above, shall mean the respective hourly PJM Day-Ahead Locational Marginal Price ("LMP") for the applicable PJM load zone, or any successor thereto, which includes the Customer's service location. In the event of any future change in PJM's process for determining the price reflecting the cost to procure energy in the PJM market to serve the Customer's Generation Energy, the Day-ahead LMP shall represent the similar or like method used by PJM for determining the Day-ahead LMP.

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SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

X. DETERMINATION OF FUEL-RELATED OR GENERATION-RELATED ELECTRICITY SUPPLY SERVICE RIDER CHARGES

As identified in Paragraph II.B.1.b., above, the Customer's Generation Energy Charge is inclusive of all applicable charges (whether applied on a per-kWh or a per-kW basis in accordance with Paragraph X.A. or Paragraph X.B., below) for the fuel-related or generation-related Electricity Supply Service Riders, which are included in the Exhibit of Applicable Riders. Such fuel- related or generation-related Electricity Supply Service Rider Charges are not billed in addition to the Market-based Rate Generation Charges. This provision shall not apply to any Commission approved charges that are non-bypassable under Virginia law, unless the Customer meets the statutory requirements for exemption from such charges.

A. The fuel-related Electricity Supply Service Rider Charge is calculated by multiplying the rate in the fuel-related Electricity Supply Service Rider, which is included in the Exhibit of Applicable Riders, by the Customer's total kilowatt-hour usage measured by the Company for the current billing month.

B. Each generation-related Electricity Supply Service Rider Charge shall be calculated using the applicable per- kW demand rate in each generation-related Electricity Supply Service Rider (using the Schedule GS-3 rate for secondary service voltage or the Schedule GS-4 rate for primary or transmission service voltage), which is included in the Exhibit of Applicable Riders, multiplied by the Customer's On-peak Generation Demand determined by the Company in Paragraph XI., below, for the current billing month.

XI. DETERMINATION OF ON-PEAK ELECTRICITY SUPPLY DEMAND

The kW of demand billed under Paragraph X.B., above, shall be the highest of:

A. The highest average kW measured in any 30-minute interval of the current billing month during on-peak hours;

B. Seventy-five percent of the highest kW of demand at the Customer's service location as determined under Paragraph XI.A., above, during the billing months of June through September of the preceding 11 billing months.

C. 100 kW.

(Continued)

XII. DETERMINATION OF ON-PEAK AND OFF-PEAK HOURS

The following on-peak and off-peak hours are applicable to the billing of the generation-related Electricity Supply Service Rider Charges in Paragraph X., above.

A. On-peak hours are as follows:

   1. For the period of June 1 through September 30, 10 a.m. to 10 p.m., Mondays through Fridays.

   2. For the period of October 1 through May 31, 7 a.m. to 10 p.m., Mondays through Fridays.

B. All hours not specified in Paragraph XII.A., above, are off-peak.

XIII. DETERMINATION OF MONTHLY LOAD FACTOR

The Company shall calculate the Customer's Monthly Load Factor for the current billing month at the Customer's service location, using the following formula:

Monthly Load Factor = Total kWh ÷ (24 * Maximum kW of Demand * Days)

Where:

Total kWh = Customer's actual monthly total kWh energy consumption for the current billing month;

24 = 24 hours per day;

Maximum kW of Demand = the higher of the Customer's (i) highest average 30-minute demand measured by the Company during the on-peak hours or (ii) the highest average 30-minute demand measured by the Company during the off-peak hours for the current billing month at the Customer's service location;

Days = the number of days in the current billing month.

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SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

XIV. DETERMINATION OF KW OF DEMAND FOR CUSTOMER'S MONTHLY DEMAND-RELATED TRANSMISSION SERVICE CHARGES AND CREDITS

A. The kW of demand to be billed for the Customer's Monthly Demand-Related Transmission Service Charges and Credits billed in Paragraph II.B.2.a., above, for the current billing month shall be determined in accordance with Paragraph XIV.B., below.

B. The following terms shall have the meanings shown below:

"DOM Zone's Network Service Peak Load" – the DOM Zone's hourly peak load in megawatts for the twelve (12) months ended October 31 of the previous year;

"DOMLSE Network Service Peak Load" – the DOMLSE's hourly load in megawatts in the hour coincident with the DOM Zone's Network Service Peak Load;

"Customer's Network Service Peak Load" – the Customer's hourly load in kilowatts in the hour coincident with the DOMLSE's Network Service Peak Load. The Customer's Network Peak Load is billed in the applicable of Paragraph II.B.2.a., above, for each billing month in the current calendar year.

C. The Company shall use the methodology used by PJM, described above, to determine the Customer's Network Service Peak Load applicable to the Customer's service location. In the event of any future change in the PJM Open Access Transmission Service Tariff methodology applicable to the DOM Zone for determining the Customer's contribution to PJM's Network Service Peak Load and, subsequently, the Customer's Network Service Peak Load, the Customer's Network Service Peak Load shall represent the similar or like method in the PJM Open Access Transmission Service Tariff applicable to the DOM Zone for determining the Customer's contribution to PJM's Network Service Peak Load.

(Continued)

XV. DETERMINATION OF CHARGE FOR CUSTOMER'S MONTHLY DEMAND-RELATED TRANSMISSION SERVICE CHARGES AND CREDITS

The Customer's Demand-Related Transmission Service Charges and Credits, billed in Paragraph II.B.2.a., above, for the current billing month shall be the Customer's Network Service Peak Load in Paragraph XIV.B., above, multiplied by the per kW demand rate in the applicable transmission riders, included in the Exhibit of Applicable Riders.

XVI. DETERMINATION OF CUSTOMER'S MONTHLY OTHER A 4 CHARGES AND CREDITS CHARGE

The Customer's Monthly Other A 4 Charges and Credits, billed in Paragraph II.B.2.b., above, for the current billing month shall be the Customer's total monthly kWh consumption at the Customer's service location, multiplied by the per-kWh rate in the applicable transmission riders, included in the Exhibit of Applicable Riders.

XVII. DETERMINATION OF TEST DEMAND AND NON-TEST DEMAND

A. Periodically, the Customer may have to conduct equipment testing at the Customer's service location. Customer's equipment testing that may result in the establishment of an abnormally high average 30-minute peak measured demand ("Peak Demand") during one or more billing months at the Customer's service location. The Company will disregard the Peak Demand for the purposes of calculating the Customer's Monthly Load Factor and the Customer's Margin, in accordance with Paragraph II.B.1.e., above, for the current billing month when *all* of the following criteria are met:

1. Customer conducted the equipment testing at the Customer's service location; and

2. The Customer's notification to the Company and conduct of the equipment testing were in accordance with the provisions of the *Customer's Equipment Testing Agreement;* and

(Continued)

XVII. DETERMINATION OF TEST DEMAND AND NON-TEST DEMAND (Continued)

3. The Customer's Peak Demand was established during the date(s) and time(s) identified by the Customer on the "Official Test Schedule," which was submitted to the Company pursuant to the *Customer's Equipment Testing Agreement;* and

4. The Company approved the Customer's Peak Demand to be a Test Demand, using the provisions of the *Customer's Equipment Testing Agreement.*

The Company shall disregard any Test Demand for the Customer only from the calculation of the Customer's Monthly Load Factor for the purposes of calculating the Customer's Margin during the current billing month.

B. Using the Company's meter data records, the Company will determine the Customer's highest average 30-minute measured peak demand outside of the dates and times listed on the "Official Test Schedule" as the Customer's Non-Test Demand for the current billing month at the Customer's service location. The Company shall use the Customer's Non-Test Demand to calculate the Customer's Monthly Load Factor for the purposes of calculating the Customer's Margin, in accordance with Paragraph II.B.1.e., above.

XVIII. METER READING AND BILLING AND PAYMENT

A. If applicable, the Customer has installed and provided the Company with access to mutually agreed upon communication technology necessary for the Company to communicate with its metering equipment. Such communication technology shall be provided to the Company's metering equipment at the Customer's own expense.

B. When the actual number of days between meter readings is more or less than 30 days, the Basic Customer Charge, the Distribution Demand Charge, the rkVA Demand Charge, each per-kW generation-related Electricity Supply Service Rider Charge, the Demand-Related Transmission Service Charges, and the minimum charge of the 30-day rate will each be multiplied by the actual number of days in the billing period and divided by 30.

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SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

XIX. STANDBY, MAINTENANCE OR PARALLEL OPERATION SERVICE

A Customer requiring standby, maintenance or parallel operation service may elect service under this Schedule provided the Customer contracts for the maximum kW which the Company is to supply. Standby, maintenance or parallel operation service is subject to the following provisions:

A. Suitable relays and protective apparatus shall be furnished, installed, and maintained at the Customer's expense in accordance with specifications furnished by the Company. The relays and protective equipment shall be subject, at all reasonable times, to inspection by the Company's authorized representative.

B. In case the Distribution Demand determined under Paragraph III. exceeds the contract demand, the contract demand shall be increased by such excess demand.

C. The demand billed under the applicable of Paragraph II.A.2.a. or Paragraph II.A.2.b., above, shall be the contract demand.

XX. DEFINITION OF TRANSMISSION, PRIMARY AND SECONDARY VOLTAGE CUSTOMER

A. A transmission voltage Customer is any Customer whose delivery voltage is 69 kV or above and is the voltage that is generally available in the area.

B. A primary voltage Customer is any Customer (a) served from a circuit of 69 kV or more where the delivery voltage is 4,000 volts or more, (b) served from a circuit of less than 69 kV where Company-owned transformation is not required at the Customer's site, (c) where Company-owned transformation has become necessary at the Customer's site because the Company has changed the voltage of the circuit from that originally supplied, or (d) at a location served prior to October 27, 1992 where the Customer's connection to the Company's facilities is made at 2,000 volts or more.

C. A secondary voltage Customer is any Customer not defined in Paragraph XX.A. or Paragraph XX.B., above, as a transmission or primary voltage Customer.

(Continued)

SCHEDULE MBR
LARGE GENERAL SERVICE
MARKET-BASED RATE
(EXPERIMENTAL)

(Continued)

XXI. CUSTOMER AUTHORIZATION

The Customer authorizes the Company to allow its Energy Supply personnel to have full access to the Customer's specific load, pricing, and any other necessary Customer specific information during the Term of Contract. Such authorization will allow the Company's Energy Supply personnel to support certain Company-specific activities resulting from Customer's participation on this Schedule.

XXII. PERIODIC REVISION OF RATES

The rates contained in this Schedule and in all the applicable riders for this Schedule are subject to change from time-to-time by order of the Commission. The rates for the currently-effective Rate Schedules and all the applicable riders are available on the Company's Internet website.

XXIII. ENROLLMENT PERIOD

The Company must receive the Customer's request for service at the Customer's service location, in accordance with this Schedule, by October 31, 2022, when this Schedule shall close to additional Customers. In addition, all of the criteria in Paragraph I.A. and Paragraph I.B. of this Schedule must be satisfied in sufficient time for the Customer to begin receiving service under this Schedule at the Customer's service location on or prior to December 31, 2022. Unless earlier terminated in accordance with Paragraph XXIV. below, this Schedule shall be withdrawn from service on December 31, 2025, absent further direction from the Commission, and shall no longer be available to the Customer at the Customer's service location. Upon such termination or withdrawal, the Customer shall select an applicable, alternative Rate Schedule.

XXIV. TERM OF CONTRACT

The term of contract for the purchase of Electric Service, including Electricity Supply Service, from the Company under this Schedule shall be for an initial minimum term of three (3) years, which will automatically renew for additional one-year terms throughout the life of the tariff. The Company or the Customer may terminate service under this Schedule by providing the other party with written notice of termination at least sixty (60) days prior to the end of the then-current term. If service under this Schedule is terminated in accordance with this Paragraph XXIV., the Customer shall select an applicable, alternative Rate Schedule.

RATE 831
RATE FOR ELECTRIC SERVICE
INDUSTRIAL POWER SERVICE - LARGE

TO WHOM AVAILABLE

Available to Industrial Customers taking service at Transmission or Subtransmission voltage whose Premises are located adjacent to existing electric facilities having Transmission or Subtransmission capacity sufficient to meet the Customer's requirements. Customer shall contract for a definite amount of electrical demand which shall not be less than 10,000 kWs. The Company shall not be obligated to supply electrical Energy in excess of the definite amount specified in the contract.

For multiple Premises held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1) and having the same qualifying service voltage, Interval Data Recorder (IDR) meters with 5-minute interval telemetry capability at those Premises can be aggregated for billing purposes if at least one of those meters has a load of 10,000 kWs or more for the last 12 months. Transmission charges will be applied to the gross energy consumption (not netted with potential outputs from other qualifying meters) of each individual IDR meter. Netting for Transmission Charges will be allowed for multiple meters at each Customer Premise. The specific IDR meters that will be applied for aggregation will be specified in the contract.

Customer's elections under Rate 831 Tiers 2 and/or Tier 3 shall occur in a window between the day after NIPSCO's compliance filing in this Cause to thirty (30) days thereafter. Customer recognizes that in order to implement Tier 3, customer may need to install software including a security certificate to be provided by NIPSCO. The Customer and Company agree to work together during the 30 day period to achieve implementation.

For any qualifying customer that is unable to take service under Rate 831 on its effective date, the customer will be able to take service under the transition service in either Rate 832 or 833 through May 31, 2020. The customer will be required to maintain their current 2019/2020 MISO Planning Year LMR registration and be required to subscribe to their portion of the Tier 1 service in the Phase 2 true up once the rates take effect.

CHARACTER OF SERVICE

The Company will supply metered Transmission or Subtransmission service to the extent of the Transmission capacity available from its electric supply lines, at such frequency, phase, regulation and voltage as it has available at the location where service is requested.

The Customer, at its own expense, shall furnish, supply, install and maintain, beginning at the point of delivery, all necessary equipment for transmitting, protecting, switching, transforming, converting, regulating, and utilizing said electric Energy on the Premise of the Customer.

The Customer will also supply in accordance with plans and specifications furnished by the Company and at a mutually agreed upon location on the Customer's property, suitable buildings, structures, and foundations to house and support the metering and any protecting, switching, and relaying equipment that may be supplied by the Company.

RATE 831
RATE FOR ELECTRIC SERVICE
INDUSTRIAL POWER SERVICE - LARGE

CHARACTER OF SERVICE (Continued)

Customers electing Tier 2 and Tier 3 service shall contract for and specify a Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises under this Rate Schedule. Tier 2 and Tier 3 service shall by default be curtailable. Customers electing service under Tier 2 and Tier 3 of this Rate Schedule shall specify the firm portion of their Tier 2 and Tier 3 Contract Demand for each affected Premise or aggregated Premises that the Customer intends to exclude from MISO Curtailment. Customers shall also meet the applicable Load Modifying Resource (LMR) requirements pursuant to MISO's Tariff Module E-1 or any successor if firm capacity is not purchased or otherwise procured as allowed under Tier 2 and Tier 3. If a Customer's elected service under this Rate Schedule results in curtailable demand under Tier 2 and Tier 3, the Customer shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction that the Customer has the ability to reduce load to any firm capacity within Tier 1, Tier 2, and Tier 3.

Any Applicant requiring service differing from that to be supplied by the Company as herein provided shall provide proper converting, transforming, regulating or other equipment upon Applicant's Premise and at Applicant's expense. (See Company Rule 3 for the Company's standard voltages.)

SERVICE TIERS

Tier 1: Firm Service

The default Tier 1 Contract Demand election is 30,000 kW with an option to elect above or below that amount down to 10,000 kW. The firm Energy is calculated on an hourly basis. This service is subject to applicable Riders as identified in Appendix A.

Tier 2: Non-Firm Market Price Service

The Customer's Tier 2 Contract Demand is the Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 Contract Demand election and any Tier 3 Contract Demand election by the Customer. This service is subject to applicable non-production Riders as identified in Appendix A. Customer will take all Energy under this Tier 2 service at Day-Ahead LMP at the applicable Company Load Zone (NIPS.NIPS) plus Transmission Charges contained within this Rate Schedule. By September 30 of each year, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements.

RATE 831
RATE FOR ELECTRIC SERVICE
INDUSTRIAL POWER SERVICE - LARGE

SERVICE TIERS (Continued)

Tier 2 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity. A customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 2 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 2 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor for this portion of their Tier 2 Contract Demand.

Tier 3: Non-Firm Third Party Generation Service

Customer may elect a Tier 3 Contract Demand up to Customer's Planning Reserve Margin Requirement using the Company's forecasted Coincident Peak demand for the Customer less the Customer's Tier 1 firm Contract Demand election. To the extent a Customer declines to elect the Tier 3 Contract Demand to which it is entitled under this Rate Schedule, it must elect to take Tier 2 Contract Demand. If the Customer elects to take any Tier 3 Contract Demand, NIPSCO, as the Market Participant, will register that Customer as an Asset Owner at MISO. Tier 3 service is subject to applicable non-production Riders as identified in Appendix A. If, under the MISO Asset Owner framework, a Customer has not arranged for any third party Energy with NIPSCO as the contracting Market Participant, Customer will take all Energy under this Tier 3 service at market price (LMP at the applicable Company Load Zone (NIPS.NIPS) plus all applicable MISO market settlement charges plus the Transmission Charge contained within this Rate Schedule. Customer will be responsible for all market settlement charges incurred by either NIPSCO as the Market Participant or the Customer as Asset Owner for any third party Energy or Capacity arrangements including, but not limited to, transmission charges to deliver energy. MISO Market Portal access will be provided as required to carry out MISO Asset Owner functions. All settlements associated with energy offers and demand bids will be passed through to the Customer. By September 30 of each year, the Company will share with the Customer its Planning Reserve Margin Requirement, forecasted Coincident Peak demand and the supporting documentation for the values. Customer shall have 30 calendar days to dispute these values. The Company will make all reasonable efforts to resolve any such disputes; however, as the Market Participant, the Company is responsible for all forecasted needs and its subsequent forecast methodology, which is subject to audit by MISO. Company will submit the Customer's Planning Reserve Margin Requirements and Coincident Peak demand on November 1 of each year to comply with MISO's Resource Adequacy Requirements.

Tier 3 Contract Demand is firm only to the extent that it is supported by Customer-procured capacity.

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RATE FOR ELECTRIC SERVICE
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SERVICE TIERS (Continued)

A customer may procure capacity outside of MISO Zone 6, provided that any charges related to that capacity including delivery into NIPSCO's zone are directly assigned to the responsible customer and that the customer accepts responsibility for such charges. NIPSCO, as the Market Participant, will register as an LMR at MISO that portion of a Customer's Tier 3 Contract Demand for which capacity is not procured through MISO's PRA or contracted through a third party. Such portion of a Customer's Tier 3 Contract Demand is non-firm, subject to MISO Curtailment. Customers must meet all applicable LMR requirements pursuant to MISO Tariff Module E-1 or any successor for this portion of their Tier 3 Contract Demand.

METER FLOW AND CURTAILMENT ORDER

Definition of meter flow shall be defined as follows:

Meter Flow	Service
↓	Applicable service taken under Rider 876
	Tier 1: Firm Service
	Tier 2: Market Price Service
	Tier 3: Third Party Generation Service

The above meter flow is for Energy only. For MISO Curtailments, the meter flow shall be defined as follows:

Meter Flow	Service
↓	Tier 2 and Tier 3: Non-Firm
	Applicable service taken under Rider 876

MISO CURTAILMENT AND FIRM CAPACITY OPTIONS

The Company shall dispatch Customers for MISO Curtailments at its own discretion in accordance with the limitations specified under this Rate Schedule and the Company Rules.

The Company shall register the portion of all Customer Contract Demand above its Tier 1 level as an LMR with MISO and shall be subject to MISO Curtailments under this Rate Schedule. Customer shall meet the applicable LMR requirements pursuant to MISO's Tariff Module E-1 or any successor. A Customer may elect to reduce all or part of its LMR obligation by procuring capacity in the MISO PRA or capacity through third party arrangements, at the Company's applicable zone defined within MISO's PRA. If Customer elects to reduce all or a portion of its LMR obligation through MISO's PRA, NIPSCO will self-schedule (price-taker) such capacity on the Customers behalf. Customers that fail to meet the requirements of a LMR or do not otherwise procure capacity will be subject to any capacity replacement/deficiency charges, and any penalties incurred as a result of maintaining Customer's Resource Adequacy needs.

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MISO CURTAILMENT AND FIRM CAPACITY OPTIONS (Continued)

Notwithstanding anything to the contrary in this rate schedule, Tier 2 and Tier 3 Customers will be provided at least two (2) hours advanced notice of MISO Curtailments. Tier 3 Customers will be able to determine the parameters associated with registration as a LMR, other than curtailment notice time, pursuant to the MISO Tariff and BPM. NIPSCO may add additional time to the LMR notification time to allow for the communication of any MISO curtailment event consistent with MISO LMR requirements.

In the event of a material change in circumstances due to a force majeure, or otherwise, that effects the ability of a Customer to comply with part or all of its LMR obligations with MISO, the Customer shall immediately notify the Company. The Company will in turn notify MISO of a need to change the Customer's LMR registration. Modifications to LMR intra to the MISO Planning Year may trigger replacement capacity provisions within the MISO Tariff and may require the Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties.

MISO ASSET OWNER REGISTRATION

For a Customer electing Tier 3 service, registration will follow MISO's quarterly network model update cycle. During quarterly network model updates, the Company will request registration of a CP Node which is required for participation as an Asset Owner under this Rate Schedule. The CP Node will be mapped to MISO EP Nodes in the same manner as the NIPS.NIPS CP Node to the extent model modifications are allowed under MISO Rules. Refer to the market registration section of the MISO BPM for details on the data required to register.

COMMUNICATIONS, METERING, TELEMETRY, HARDWARE, AND SOFTWARE REQUIREMENTS

The Company shall specify a communications plan, which includes a revenue quality meter and all implementation and operational software required under this Rate Schedule. It is the Customer's responsibility to comply with that plan. The Customer will pay for the installed cost of additional metering, telemetry, hardware and software development, certificates, and licensing fees that may be required to facilitate service under this Rate Schedule. All such metering shall be compliant with any applicable current and future MISO and/or IURC requirements, including the potential of meter capture on a 5 minute basis. The Customer shall provide the Company with next day remote interrogation of the meter on an hourly level. The Customer may elect to install its own metering, with the Company reserving the right to inspect the equipment and own the equipment once it is installed. At the Customer's request, metering may be installed by the Company and invoiced at the installed cost to the Customer. Estimated costs of metering and equipment shall be provided prior to installation by the Company, but the Customer shall be responsible for the actual costs of the equipment and installation.

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DEMAND BIDS

For a Customer electing Tier 3 service, the Customer will have the ability to submit Day-Ahead Demand Bids for a portion or all of their Tier 3 daily demand through the MISO Market Portal. Day-Ahead Demand Bids not received by MISO in accordance with the MISO BPM will be settled at Real Time LMPs and assessed any applicable additional MISO charges. Refer to the Demand Bid section of the MISO BPM for details on the requirements of the Demand Bid.

MISO COMMUNICATIONS

For a Customer electing Tier 3 service, all clearing, pricing and settlement activity will be available on the MISO Market Portal. Revenue quality meter data will be interrogated by the Company on a daily basis and submitted by the Company to MISO on behalf of the Customer.

MISO SETTLEMENTS

For a Customer electing Tier 3 service, MISO Settlement Statements are posted daily by MISO to the MISO Market Portal. The Customer shall obtain the MISO Settlement Statements from the MISO Market Portal. The Customer shall be responsible for the review of the Customer's MISO Settlement Statements. All charges reflected on the Customer's MISO Settlement Statements will be the Customer's responsibility and are payable to the Company on a weekly basis. MISO Settlement Statement charges will be determined by the Customer's Day-Ahead Demand Bid (at Day-Ahead LMP) and the imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand (at Real-Time LMP). Any imbalance between the Customer's Day-Ahead Demand Bid and the Customer's actual metered Demand will also be assessed any applicable MISO charges including a Revenue Sufficiency Guarantee charge. MISO Settlement Statements will also include the Customer's share of Market Uplift charges and an administrative fee that is charged by MISO to support the operation of the market. The Customer's MISO Settlement Statements will follow the settlement timeline that is outlined in the MISO BPM, which may also include special resettlements that are deemed necessary by MISO. Refer to the MISO BPM for details on the MISO Settlement Timeline and Settlement Charge calculations.

DISPUTES

For a Customer electing Tier 3 service, the Customer has the right to dispute any MISO charges. The Customer, through the MISO Market Portal, will provide all required data to MISO to support the dispute. The Customer shall notify the Company of any filed disputes and disposition by MISO within 24 hours of such notification. Notification of disputes shall include a copy of the dispute submitted by the Customer along with any correspondence between the Customer and MISO including, but not limited to, the final resolution of the dispute. Notification shall be remitted to the Manager, Market Settlements of the Company. Third party energy and capacity suppliers may also represent the industrial customer's interests in the event of a dispute with MISO, FERC, or the IURC. At a

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DISPUTES (Continued)

minimum, NIPSCO should be kept informed of the dispute process and may need to be a party to the process.

Disputes that have been denied by MISO may be disputed through the MISO Alternative Dispute Resolution (ADR) process in accordance with MISO Rules. The Company as the Market Participant must file ADR disputes on the Customer's behalf as currently Asset Owners cannot file an ADR. The Customer must provide written notification in compliance with the timelines established by Attachment HH of the MISO Tariff to the Company requesting the Company to proceed with the mechanism available to resolve these disputes outside of the judicial or administrative agency proceedings. This would include informal dispute resolution, or formal mediation or arbitration. The Company will make a good faith effort to prosecute the dispute. The Company will provide the Customer an initial preliminary estimate for costs associated with the ADR. Customer must submit payment in accordance with the estimate established if the Customer wishes to pursue the ADR at MISO. The written notification shall be remitted to the Manager, Market Settlements of the Company.

The hierarchy as it stands allows an Asset Owner to file the dispute with MISO. If the dispute is denied and the Customer wants to pursue it further, the Customer needs to request NIPSCO to file an ADR on its behalf with MISO. If the Customer is unsatisfied with MISO's decision, it can pursue a complaint with FERC on its own.

It is the responsibility of the Customer to pay all assessed MISO Settlement Statement charges to the Company when due at the time of assessment. Any necessary adjustments to the settlement amounts will be made by MISO after dispute resolution. Refer to the MISO BPM for details on the requirements of the Dispute and ADR process.

REGISTRATION

Customers electing non-firm service and or registration as an LMR will provide all required data to the Company per MISO's Resource Adequacy BPM. The Company may request additional data as requested by MISO to support any and all Resource Adequacy compliance requests. MISO's capacity Planning Year is June 1 through May 31. All required information must be entered prior to due dates to ensure capacity positions are established. Once the PRA has cleared, modifications can be made per limitations and penalties as outlined in MISO's Tariff Module E-1.

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REGISTRATION (Continued)

The following table provides an overview of Tier requirements. All requirements and dates are pursuant to MISO's Tariff Module E-1 or any successor and may be modified by MISO. Customer shall provide required information to the Company ten (10) business days prior to MISO Planning Resource Timeline in accordance with MISO BPM-011, Appendix K:

Requirement	Tier 2	Tier 3
Coincident Peak Demand forecast, Non-Coincident Peak, and energy forecast		X
Existing Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
New Load Modifying Resource/Energy Efficiency Resource registration to be considered for inclusion in FRAP must be submitted for approval		X
New Load Modifying Resource/Energy Efficiency Resource must be submitted for approval	X	X
Planning Resource Auction offer window is open		X
Planning Resource Auction offer window is closed		X
Planning Resource Auction results posted		X

DETERMINATION OF AMOUNT OF ELECTRIC SERVICE SUPPLIED

The electric service to be supplied under this Rate Schedule shall be measured as to Maximum Demand, Energy Consumption and kVAR by an IDR to be installed by the Company.

RATE

Rates charged for service rendered under this Rate Schedule are based upon the measurement of electric Energy at the voltage supplied to the Customer.

After aggregation of Customer's Premises, Customer Energy delivered onto the Company's Transmission or Subtransmission system at an integrated hourly level shall be paid to the Customer at the Real Time LMP at the Company's Load Zone.

The electric service and Energy supplied hereunder shall be billed under a three-part rate consisting of a Demand Charge, Energy Charge, and Transmission Charge, and applicable Riders as identified in Appendix A. The Demand Charge, Energy Charge, and Transmission Charge are as follows:

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RATE (Continued)

Demand Charge

Tier 1

$25.24 per kW per month

Energy Charge

Tier 1

$0.029572 per kWh for all kWhs used per the month.

Tier 2

All kWhs used above the specified Tier 1 Firm Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone, if Customer does not have a Tier 3 Contract Demand. If Customer has a Tier 3 Contract Demand, all kWhs used above the specified Tier 1 Firm Contract Demand not in excess of Tier 2 Contract Demand shall be subject to an Energy Charge equal to the Day Ahead LMP for the Company's Load Zone.

Tier 3

All kWhs used above the specified Tier 1 and Tier 2 Contract Demand shall be subject to MISO Settlement Charges related to a Customer's Asset Owner activity.

Transmission Charge

$0.008525 per kWh for the gross Energy consumed at each IDR, netted by Premise (Tier 1, Tier 2, and Tier 3).

Adjacent Affiliate Qualifying Facility Premise Transmission Charge

$0.002557 per kWh for the gross Energy transferred from a premise with behind the meter generation to an adjacent premise held under common ownership or by affiliates (as defined in Indiana Code § 23-1-43-1). If the Customer's premises were served under NIPSCO's prior Rate 732, the gross Energy transferred from a premise will be determined by netting in the applicable monthly billing period the amount of self-generated Energy and metered consumption.

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DETERMINATION OF DEMAND

The Customer's Demand of electric Energy supplied shall be determined for each half-hour interval of the month and said demand in kWs for each half-hour interval shall be two (2) times the number of kWhs recorded during each half-hour interval. The phrase "half-hour interval" shall mean the thirty (30) minute period beginning or ending on a numbered clock hour as indicated by the clock controlling the metering equipment.

The Customer's current integrated Demand shall be determined for each MISO settlement period for load as the total kWh recorded during that MISO settlement period multiplied by the ratio of 60 minutes to the total number of minutes in that MISO settlement period.

DETERMINATION OF LAGGING kVAR

The Customer's requirements in Lagging kVAR shall be determined for each half-hour interval of the month and shall be two (2) times the number of Lagging kVAR Hours recorded during each half-hour interval. No effect whatsoever shall be given hereunder to Customer's leading kVAR, if any.

ADJUSTMENT FOR CUSTOMER'S PEAK HOURS LAGGING kVAR

The number of kVAR shall be computed each month for a Power Factor of eighty-five percent (85%) Lagging using as the basis of said computation, the Customer's Maximum Demand for the month during the Peak Period hours thereof.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is greater than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of $0.32 times said difference shall be added to the Customer's Bill.

If the Customer's Maximum Peak Period Requirement in Lagging kVAR for the month is less than the number of kVAR at a Power Factor of eighty-five percent (85%) Lagging, as determined above, an amount equal to the product of $0.32 times said difference shall be deducted from the Customer's Bill.

The Customer agrees to control and limit Maximum Off-Peak (weekdays 22:00 – 06:00 CST, all weekend hours, and all hours during NERC holidays) Period Requirement in Lagging kVAR so that, as related to the Maximum Off-Peak Period kW Demand, it shall not exceed in ratio or numerical proportion the ratio of the Maximum Peak Period Requirement in Lagging kVAR and the Maximum Peak Period kW Demand; except that if such Maximum Off-Peak Period kW Demand is less than the Maximum Peak Period kW Demand, the Customer's Maximum Off-Peak Period Requirement in Lagging kVAR may equal the Customer's Maximum Peak Period Requirement in Lagging kVAR.

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CUSTOMER LOAD INFORMATION

If requested by the Company, the Customer shall cooperate with the Company by furnishing the Company in writing on or before the first day of July each year a statement of the Customer's estimates of the Customer's future load on the Company by months for a subsequent period of thirty (30) months.

The Customer shall also make a good faith effort to provide the Company in writing with an accurate hourly load forecast on a daily basis.

The Customer shall notify the Company in writing of any material increase in load no less than sixty (60) days prior to the addition of that load.

The Customer's dispatcher shall cooperate with the Company's dispatcher by furnishing, from time to time, such load information and operating schedules which will enable the Company to plan its generating operations.

The accuracy of the information herein called for is not guaranteed by the Customer and reliance thereon shall be at the sole risk of the Company.

Failure by the Customer to provide requested information on an ongoing basis may result in Customer being moved to another Rate Schedule upon ninety (90) days' notice from the Company to Customer.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED MISO CURTAILMENT

A Customer is deemed to have failed to comply with a MISO Curtailment when the Customer's current integrated Demand, as measured by the meters installed by the Company (netted across aggregated Customer Premises, if applicable), has not decreased to a level of the sum of the Customer's specified Tier 1, firm Tier 2 and firm Tier 3 Contract Demands.

If a Customer fails to comply with a MISO Curtailment, the Customer shall be liable for any charges and/or penalties from any governmental agency(ies) having jurisdiction or duly applicable organization including MISO, FERC, NERC and Reliability*First* for failure to comply with a MISO Curtailment. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR to the extent such penalties are specifically invoked on the Company due to the failure of the Customer to comply with the Curtailment.

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RATE FOR ELECTRIC SERVICE
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GENERAL TERMS AND CONDITIONS OF SERVICE

1. Contract

Any Customer requesting service under this Rate Schedule shall enter into a written contract for an initial period of not less than five (5) Contract Years. The Customer maintains the ability to cancel the contract if the entire Premise is closing. For customers who are aggregating Premises, if one Premise closes, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kWs. For a Customer partially closing a Premise, the Customer may modify its Tier 1 Contract Demand with 12 months' notice, but it may not go below 10,000 kWs. The Customer may increase the Tier 1 firm Contract Demand election with five (5) years' notice and a period of not less than five (5) Contract Years. On a quarterly basis, consistent with the MISO Commercial Model timing, a Customer may elect to move all, or a portion, of its election(s) under Tier 2 and Tier 3 between such.

Notwithstanding the foregoing, contracts under this Rate Schedule shall terminate in accordance with Rule 5.8 of the Company Rules.

2. Third Party Contracts

Any Third Party Contracts for energy under Tier 3 and/or capacity under Tier 2 and/or Tier 3 shall include, at a minimum, the following provisions:

i. identify NIPSCO as the Market Participant for the retail customer at MISO;
ii. reference NIPSCO's market-based rate authority with FERC;
iii. clearly state the Rate 831 customer remains a retail customer of NIPSCO;
iv. indemnify NIPSCO from any financial or performance obligations under any physical energy or capacity agreement (the terms of any such agreement will link to the end use customer, who will wholly bear the risk associated with its contractual obligations);
v. incorporate relevant provisions of the Rate 831 tariff;
vi. all pricing provisions in any agreement may be redacted by the customer; however NIPSCO reserves the right to request and be provided redacted information if determined necessary; and
vii. any information shared with NIPSCO shall be subject to a confidentiality agreement.

3. Default Schedule

Notwithstanding the foregoing conditions of service under this Rate Schedule, service shall be subject to the provisions of Rule 5.9 of the Company Rules.

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GENERAL TERMS AND CONDITIONS OF SERVICE (Continued)

4. **Customer Disqualification**

Under this Rate Schedule and / or applicable Riders to this Rate Schedule, any Customer that is found to be engaging in activity that is determined to be a violation of market manipulation or antitrust rules / laws may be subject to disqualification from eligibility for Tier 3 of this Rate Schedule if any such activity disqualifies the Customer from meeting obligations set forth under this Rate Schedule. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a LMR, any market damages, or private party damages. By taking service under this Rate Schedule, the Customer agrees to fully participate in any investigation into possible violation(s).

Any Customer that is disqualified from eligibility for service under Tier 3 service shall have all of its Tier 3 Contract Demand moved to Tier 2 with all of the Customer's Tier 2 Contract Demand, including any pre-existing Tier 2 Contract Demand of the Customer, covered with capacity through MISO's PRA and replacement capacity provisions within the MISO Tariff and may require Customer to procure replacement capacity or pay MISO capacity deficiency charges / penalties. The Customer will not be eligible for Tier 3 service and LMR registration for a period of five (5) years. After the five (5) year period, the Customer may be allowed to return to Tier 3 under this Rate Schedule or successor.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules, IURC Rules, and MISO Rules.

DAY AHEAD MARKET PRICING RIDER

ELECTRIC D

1. Effective In

   The Day Ahead Market Pricing Rider ("Rider") is available in all territory served by Wisconsin Power and Light Company (the "Company" or "WPL").

2. Availability

   The Rider participation limit is a program maximum of 50 MW total load.

   This Rider is available to customers served under Rate Schedule Cp-2. This Rider cannot be concurrently utilized by customers taking service under other rider rate schedules.

   This Rider is not available to customers or potential customers transferring load from a different electricity provider in Wisconsin to WPL.

   Participation in this rider is limited to two contract terms. N

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3. Rate

   Each customer will have unique Baseline Levels for energy and demand usage as outlined in the Baseline Determination section of this Rider. A customer will be charged according to the applicable standard tariff rates for their usage up to and including their Baseline Levels. Incremental usage above the Baseline Levels will be charged at market-based energy and incremental demand rates specified in this Rider.

   Administrative Charge per Day: $6.00

DAY AHEAD MARKET PRICING RIDER

ELECTRIC

Baseline Level Charges: The Schedule Cp-2 rate, definitions, rules and riders apply to all energy and demand consumption that does not exceed the Baseline Levels for the month.

Above Baseline Level Charges: The following charges shall apply to all energy and demand consumption in excess of the Baseline Levels for the month.

A) Incremental Energy Rate ("IER") - If the customer's energy consumed exceeds Baseline Levels in any hour of the billing month, the incremental energy above the Baseline Levels will be charged the following IER components:

1) The hourly Midcontinent Independent System Operator, Inc. ("MISO") Day-Ahead Locational Marginal Pricing for the ALTE.ALTE pricing load zone.

2) Transaction costs charged and credited to the Company by MISO. WPL will annually update the per unit rate to be effective each January based on the costs from the prior November-through-October time period. These charges include, but are not limited to:

   a. Regulation Cost Distribution Amount (MISO Schedule 3);
   b. Spinning Reserves Cost Distribution Amount (MISO Schedule 5);
   c. Supplemental Cost Distribution Amount (MISO Schedule 6);
   d. Revenue Sufficiency Guarantee Distribution Amount;
   e. Revenue Neutrality Uplift Expense; and
   f. Distribution of Losses Credit.

3) Energy-based transmission and dispatch operation costs charged to the Company by American Transmission Company ("ATC"), MISO or their successors for costs to provide transmission service to the customer. WPL will use the base rate case cost estimates to determine a per unit rate, including recovery of escrow accounting cost adjustments. These charges include, but are not limited to:

   a. Multi-Value Project ("MVP") Expense (MISO Schedule 26A , as well as MVP true-up adjustments);
   b. MISO Administrative Expenses (MISO Schedule 17); and
   c. Control Area Operator Cost (MISO Schedule 24).

4) Margin on Energy at $0.0005/kWh.

5) Gross Receipts Tax applied to IER components 1) through 4) at 3.19%.

The IER will not be less than $0.019/kWh in any hour. IER components 1) and 2), as well as the associated losses from component 5) will be treated as fuel-related energy costs.

B) Incremental Demand Rate ("IDR") – If the customer's coincident demand at the time of ATC system peak exceeds Baseline Levels for the month, the incremental demand above the Baseline Levels will be charged the following IDR components:

1) Resource Adequacy Charge of $2.00 per kW.

2) ATC Network Transmission Charge. This charge will be based on the estimated rate provided by ATC.

3) Demand-based transmission costs charged to the Company from ATC, MISO or their successors for costs to provide transmission service. WPL will use the base rate case cost estimates to determine a per unit rate including recovery of escrow accounting cost adjustments. These charges include, but are not limited to the following:

a. Scheduling/Dispatch (MISO Schedule 1);
b. Voltage/Reactive Expense and Revenue (MISO Schedule 2);
c. Network Service (MISO Schedule 9);
d. Independent System Operator Cost Recovery (MISO Schedule 10);
e. FERC Administrative (MISO Schedule 10-FERC);
f. Wholesale Distribution Service (MISO Schedule 11);
g. Network Upgrade Expense (MISO Schedule 26);
h. Blackstart Service (MISO Schedule 33);
i. System Support Resources (MISO Schedule 43);
j. PJM Charges; and
k. Direct Network Upgrade Charges.

4) Gross Receipts Tax applied to IDR components 1) through 3) at 3.19%.

C) Any other credits or charges that may be authorized or mandated by the PSCW from time to time that would apply to incremental usage, including applicable Act 141 obligations.

4. Determination of Baseline Levels

A customer's Baseline Levels shall be based on a firm amount nominated by Customer for the term of the contract. Energy and Demand Baseline Levels will be contracted prior to beginning service under this Rider and will be applicable for the duration of the Contract Period. The following Baseline Levels will be established as a part of contracted service under this Rider:

hourly week day energy usage, by month;
hourly weekend energy usage, by month;
monthly firm on-peak demand;
monthly customer demand;
monthly coincident peak demand; and
monthly billed reactive energy

5. Contract Requirements

A customer subscribing to this Rider must enter into a contract for a term of five calendar years, each beginning on January 1 and ending on December 31. If the Customer wishes to begin service under this Rider on a date other than January 1, the contract term may include service for part of the then-current calendar year, in which case the requisite term of five calendar years will commence on January 1 of the next calendar year.

To remain on this rider a customer must enter into a new 1 to 5 year contract prior to September 1, with the new contract to become effective January 1st. N | | | N

The Customer may terminate service under this Rider upon no less than two years' written notice to the Company. A termination by the Customer will become effective on December 31 of the year that is two calendar years beyond the calendar year in which the Customer delivers its written notice of termination to the Company. A Customer that terminates service under this Rider may not resume service under this Rider for a period of at least one year from the date the prior service ended. If the Customer wishes to resume service after such termination, the Customer must enter into a new contract with the Company.

6. Interruptible Load Requirements

Customers under this Rider are subject to the interruption terms, provisions, and penalties outlined in the schedule Cp-INT. Customers under this Rider are subscribing to instantaneous interruptibility under rate schedule Cp-INT for all load exceeding Baseline Levels, with the following exceptions:

a) In lieu of the conditions for Economic Interruption in section 10 a) of rate schedule Cp-INT, an Economic Interruption may be called when energy prices are expected to exceed a threshold price equal to the High Rate Energy Charges in section 3C of rate schedule Cp-2 for four contiguous hours.

b) For an Economic Interruption, in lieu of the Notification requirements in section 4 of rate schedule Cp-INT, notification for an Economic Interruption will occur during the calendar day prior to the event.

c) The limitations for number of hours of interruptibility in section 10 b) of the rate schedule Cp-INT will not be applicable under this Rider.

Rider pricing, terms and conditions do not apply to any energy consumed during the curtailment or interruption event. Once a curtailment or interruption event is over, pricing, terms and conditions of delivery revert to those of this Rider. Failure to comply with interruptible load requirements may result in termination of service under this Rider.

7. Guaranteed Load Provision

Before initiating service under this Rider, the Customer will furnish to the Company a Load Financial Security Instrument ("LFSI") satisfactory to the Company in its sole discretion. The LFSI may take the form of a surety bond, letter of credit, or similar financial instrument payable to WPL, and will be in an amount agreeable to the Company that will approximate the following formula:

(X – Y) x 2, where:

X = the total cost of electric service the Customer paid (or would have paid) under rate schedule Cp-2 and applicable riders for the full calendar year immediately preceding the calendar year in which the Customer first takes service under this Rider; and

Y = the total amount the Customer would have paid for electric service under this Rider for the full calendar year immediately preceding the calendar year in which the Customer first takes service under this Rider.

If the Customer is a new customer, the LFSI will be in an amount agreeable to the Company in its sole discretion based on the estimated annual usage of the new customer.

The full amount of the LFSI will be collectible by WPL if, at any time from the date the Customer first subscribes to this Rider until the second anniversary of the Customer's discontinuation of service under this Rider, the Customer's total annual load falls below 75% of that which the Customer maintained in the full calendar year immediately preceding the calendar year in which the Customer first subscribes to this Rider.

8. Billing Cycle Accommodations

Customers taking service under this Rider will be billed on a calendar month basis. WPL reserves the right to bill IDR charges on a one month lag to allow for final determination of the coincident peak hour for the calendar month. Participants will start on the Rider at the beginning of the billing period after a contract is signed and price communication processes are functioning.

9. Energy Efficiency Adjustment N

Any time after the first contract year of this schedule, the baseline may be reduced as a result of implementation of energy efficiency, conservation, process improvement measures, or through the installation of new equipment. The customer must request a review of their historical baseline period and provide the Company with supporting documentation of the reduction. After review of and verification that reduction is permanent, an adjusted baseline will be inserted into an amended contract. This adjustment will not take effect until the beginning of the billing period following the execution of an amended contract. Baseline adjustments pursuant to this condition will not occur more than once in a twelve-month period. N