10. DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION REQUIREMENTS

Applicable to any customer installing a Distributed Energy Resource (DER) unit (e.g. distributed generator or energy storage system) 5 MW or less, connected in parallel with the Company's utility distribution system.

These requirements are not applicable to a DER unit which is not connected to the Company's distribution grid. Compliance with all other tariff provisions applicable to the Customer is required.

A. Definitions

The terms are defined as the New York State Standard Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage System 5 MW or Less Connected in Parallel with Utility Distribution Systems, as the same may be revised, modified, amended, clarified, supplemented or superseded, as posted on the NY PSC website at www.dps.ny.gov/distgen.htm, and as set forth within Addendum-SIR of this Schedule.

The Standardized Interconnection Requirements (SIR), including the standard applications and contracts, are set forth within the Addendum-SIR to this Schedule.

B. Queue Management

1. Applications submitted to the Company shall be subject to the Queue Management process as set forth within Addendum-SIR, Section II, J.

10. DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION REQUIREMENTS

B. Queue Management (Cont'd)

2. Projects that fail to meet the requirements defined in each step shall be removed from the queue with no further action required by the Company.

C. Payment
Payments made by check shall be deemed paid when the checks clear.

D. Cost Sharing Mechanisms
1. Limited Mandatory Interconnection Upgrade Cost Sharing Mechanism
This methodology applies to projects that do not otherwise meet the requirements for Cost Sharing 2.0 as defined in Rule 10.D.2.

This interim cost sharing mechanism applies to any initial projects that meet all of the following criteria:
Use Eligible Technologies.
This mechanism is applicable to projects and technologies interconnecting to the distribution grid under the NYSIR.

2. Cost Sharing
A. This mechanism is not available to projects that have 100% paid for upgrade costs, or were required to have paid for upgrade costs prior to January 25, 2016. Any project that makes 100% payment of upgrade costs after January 25, 2017, is eligible for cost sharing.

a. Specific Eligible Upgrades
This mechanism applies to upgrades that can be used by more than one project. Specifically, the following technologies are eligible for interim cost sharing:
i. Substation 3V0 installation;
ii. Substation transformer upgrades; and
iii. Other substation-level shared upgrades.

b. Minimum Cost Threshold
The mechanism is limited to eligible upgrades that cost $250,000 or more.

c. Applicability
This mechanism applies to subsequent projects that shall utilize the upgrades and meet the following criteria:
i. Projects 200 kW or Greater in Size – Any subsequent project that is equal to, or greater than, 200 kW at one point of common coupling (PCC) and uses the upgrade shall share in the upgrade cost according to this mechanism.
ii. Projects Aggregating to 200 kW or Greater in Certain Situations - Subsequent projects that utilize the upgrades, which are completed by a single developer and are equal to, or greater than, 200 kW in aggregate, and whose applications are filed within eight-months of each other.
iii. A developer is defined as the entity that submitted the interconnection application. A single developer includes all legal entities associated or affiliated with a given company, including subsidiaries, LLCs, etc.

10. DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION REQUIREMENTS

D. Cost Sharing Mechanism (Cont'd)

2. Cost Sharing (Cont'd)

d. Payment

The mechanism shall function as follows:

i. The initial project that triggers the need for the eligible upgrade pays 100% of the upgrade cost in accordance with the NYSIRs deadlines. The cost sharing mechanism is available after the initial project developer pays 100% of the required upgrade costs. The interconnecting company shall disclose the portion of the total upgrade cost that is eligible for this mechanism to the initial project developer in the CESIR, or in the Preliminary Technical Report or Supplemental Review Report if no CESIR is required.

Subsequent project developers are required to pay their prorated share of the eligible upgrade cost.

ii. This payment is made to the Company and then passed through to the project developer(s) that have previously paid for the upgrade, minus a Company processing fee. The developer(s) are responsible for any reallocation of received funds to project financiers or owners, per their own business arrangements. For all types of eligible upgrades, the prorated share for projects after the initial triggering project is based on the fraction of each MW project size compared to the total MWs of aggregated projects benefiting from the upgrade to date, including the newest project's MWs. Each project developer's prorated share of the upgrade cost shall be included in the CESIR, or in the Preliminary Technical Report or Supplemental Review Report if no CESIR is required.

iii. The Company shall deduct a processing fee from each subsequent developer check issued after the initial developer pays 100% of the upgrade costs. This $750 administrative fee may be reassessed if it is proven inadequate in practice.

e. Cost Sharing Limit

The cost sharing of an upgrade shall end when one of the conditions below is met:

i. Maximum Capacity
When the capacity of the upgrade is exhausted by projects, this limited mandatory interconnection cost sharing mechanism ends.

ii. Cost Sharing Threshold
When project developers benefitting from the eligible upgrade have expended net costs of $100,000 or less, because each developer was reimbursed by subsequent developers, cost sharing ends. Project developers that use the eligible upgrade after this point incur no mandatory interconnection upgrade cost sharing.

10. Distributed Energy Resource (DER) Interconnection Requirements (Cont'd.)

D. Cost Sharing Mechanism (Cont'd)

2. Interim Cost-Sharing Mechanism ("Cost-Sharing 2.0")

1. The Company shall determine if a project is eligible for the Interim Cost Sharing Mechanism as defined in Appendix E of the Standardized Interconnection Requirements ("SIR"). The SIR including standard applications and contracts, are set forth within Addendum-SIR to this Schedule.

2. SIR deadlines applicable to these applications shall be suspended and the interim cost-sharing mechanism shall apply. If the Qualifying Upgrades are not pre-funded through the interim cost-sharing mechanism, the already submitted applicants shall remain in the queue and subject to Cost Sharing as described in Rule 10.D.1.

3. The Company shall continue to manage applications received in accordance with the SIR. Interconnection deposit payment deadlines shall be temporarily suspended for applications at locations impacted by a Qualifying Upgrade. Later applications may opt to be treated as Participating Projects if the Qualifying Upgrade is able to accommodate them.

4. To determine the allocation for a Participating Project under the Cost-Sharing 2.0 mechanism, the following steps apply:
   a. initially determine the capacity contribution; the project's capacity divided by the sum of all projects sharing the line.
   b. the percentage of distribution line footage contribution, if applicable, is determined by dividing the Participating Project's footage use divided by the first mover project's footage. If the Participating Project uses more than the first mover's footage, then the Participating Project footage percentage will be 100%.
   c. the capacity contribution is multiplied by the footage contribution percentage to the final percentage contribution.

E. Payment

1. Payments in full of the estimate shall be made as set forth in the SIR.
   a. State Agencies shall not be required to deposit funds into an escrow account pursuant to Appendix A-2 of Addendum-SIR to this Schedule.

2. Construction of the Qualifying Upgrade shall begin once full payment of the estimate has been made by the Triggering Project, or the Sharing Project(s).

F. Allocation of Unrecovered Costs

The Company shall reconcile the outstanding upgrade costs, including carrying charges using the weighted pretax cost of capital, on an annual basis, or more frequently, if needed.

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GENERAL INFORMATION

11. GENERAL RETAIL ACCESS

A. Introduction:

1. This Section contains the terms and conditions pertaining to General Retail. The rate options under which customers may take retail access are detailed in Rule 12, Supply Service Options.

2. All transmission service within New York State is obtained through the New York Independent System Operator ("NYISO") pursuant to the NYISO Tariffs. This General Retail Access tariff may be revised, modified, clarified, supplemented, amended or superseded as may be necessary as a result of the NYISO Tariffs. The Company may seek to revise the terms and conditions of the tariff, the Electric Supplier Manual and the Operating Agreement (including any pricing terms) as necessary to comply with the requirements of the NYISO Tariffs.

B. Definitions and Abbreviations:

Definitions for terms and abbreviations pertaining to General Retail Access can be found in Rule 1, Definitions and Abbreviations, of this Tariff.

C. Customer Participation:

1. Eligibility Requirements:

Eligibility to participate in General Retail Access is open to all customers subject to requirements set forth in Rule Nos. 11 (General Retail Access) and 12 (Supply Service Options):

(a) Customers whose entire load is served under Service Classification No. 10 may be eligible for retail access after their contracts expire, unless their contracts with the Company permit such customer to become eligible earlier. Upon expiration of such contracts, customers may be eligible to select any Supply Service Option in accordance with Rule 12, Supply Service Options.

(b) Customers who receive a portion of their Electric Power Supply from NYPA(Recharge NY Power), with Standard Load (non-NYPA load) shall be permitted to take General Retail Access service for their Standard Load. If the NYPA allocation expires or is terminated, the customer will have 30 days to elect a Supply Service option for that load, subject to the provisions of Section 12, Supply Service Options.

(c) The following customer eligibility requirements also apply:

i. A Customer, whose Electric Power Supply and delivery would otherwise be provided by the Company, under S.C. Nos. 1, 2, 3, 4, 6, 7, 8, 9, 10, 11, 12, or 14; may arrange for Electric Power Supply only from an ESCO that meets the requirements set forth herein.
ii. A Customer may select only one ESCO at a time per customer account per utility type, regardless of the number of service points.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

Reserved for Future Use

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

C. Customer Participation (Cont'd)

2. Customer Information - Current

All information to be furnished by the Company shall be provided electronically via EDI to ESCOs/DCs when the data is acceptable to the Company for the purposes of billing its Customers for service provided by the Company. Where estimated meter readings are used, the estimated usage must be provided to ESCOs/DCs when the data is acceptable by the Company to bill its Customers for service provided by the Company. All subsequent changes or corrections and adjustments to previously supplied data shall be made available to the ESCOs/DCs when the data is acceptable to be used for its Customers.

3. Historical & Current Information Available Free of Charge:

For usage and billing information, the Company shall provide up to 24 months of the most recent historic usage and billing information, except as provided for in paragraph 4 below. For credit information, the Company shall provide information on whether the Customer had late payments and/or disconnections due to non-payment during the immediately preceding 24 months or life of the account, whichever is shorter.

4. Charges for Customer Information:

For historical usage and billing information, see UBP Addendum, Section 4.E.. Should a Customer and/or its designee request historical usage and billing information for more than 24 consecutive months, the Company shall provide this information (if available) for a fee of $15 for each additional twelve (12) month period or portion thereof. Should a Customer or its authorized designee request historical interval data, in special customized formats, a fee shall apply for data in excess of 24 months. Detailed interval data for an account, if available, shall be provided at a fee of $40 per meter, per request, for data in excess of 24 months. The fees detailed in this section shall be payable by the requestor. Information not identified in this paragraph shall be supplied, if available, at the Company's incremental cost. All information shall be provided via a non-EDI method. The Company reserves the right not to be required to provide data in any special customized format.

5. Sending Customer Information:

Usage and billing information shall be sent to the requestor via EDI. ESCOs shall be required to obtain and retain proper customer authorization for such information. Credit information shall be mailed to the Customer's address unless the Company receives the proper written customer authorization from the ESCO, in which case it shall be provided to the ESCO.

6. Confidentiality:

The ESCO must keep confidential any customer information (usage and billing and credit information) obtained from the Company. This information shall not be disclosed to any party, unless otherwise authorized by the Customer in writing. All other customer information, such as account numbers (and any passwords used, if applicable), telephone numbers and service addresses, shall also be kept confidential and not disclosed to others, unless otherwise authorized in writing by the Customer.

The Company shall not disclose a customer's usage and billing and credit information to an ESCO unless the Customer has notified the Company, in writing, that such information may be disclosed.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

7. Changes in Supplier:
C. Customer Participation (Cont'd)

(a) Voluntary Switch Back to the Company Service:

If a Customer voluntarily chooses to switch back to the Company service for Electric Power Supply, such Customer must notify the Company at least five business days before the Customer's next scheduled meter reading date, interim estimated meter reading date, or a requested Special Meter Reading date.

(b) Involuntary Switch:

An involuntary switch is a process or situation where a Customer's ESCO is changed from one provider e.g., ESCO or utility, to another without the Customer's authorization. An involuntary switch that is not in accord with the "Discontinuance of Service" provision set forth in the UBP Addendum, Section 2.F, is referred to as "slamming." Examples of involuntary switches include, but are not limited to, situations where a customer returns to the Company service as a result of an ESCO's failure to deliver, the ESCO going out of business, or the termination of the ESCO's participation in the Company's General Retail Access Program.

(c) Special Meter Reading Fees:

A $20 fee per customer location, per meter, per read attempt, will be charged to the party requesting a Special Meter Reading. A Special Meter Reading is a meter reading performed on a date other than the customer's regularly scheduled meter reading date. Requests for Special Meter Reading dates must be made not less than five business days in advance of the requested meter reading date.

(d) Budget Billing Adjustments:

The Company Budget Billings, as set forth in Rule 4.C.1 may be adjusted at the switch dates or as required to reflect changes in the Company's service and, if adjusted, shall be reflected in the Customer's next bill.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

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GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

Reserved for Future Use

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

C. Customer Participation (Cont'd)

8. Metering:

(a) The metering requirements set forth in this Schedule apply here. Customers shall continue to use existing meters.

(b) A Customer that does not take service under an economic incentive provision that requests a meter other than that provided by the Company, commensurate with the Customer's Service Classification, is subject to the additional requirements set forth in this Schedule. Meter upgrades, subject to the availability of equipment, shall be installed and operated by the Company at the Customer's expense.

(c) The Company shall continue to own, install, maintain, and read Customers' meters for billing purposes, with the exception of large commercial and industrial time-of-use customers who have the option of owning a Commission-approved meter as set forth in this Schedule, with the Company retaining sole control of that meter. Eligible large commercial and industrial time-of-use customers, or their designees, shall be allowed to receive meter data on a real-time or other basis, without incurring a fee, provided that such customers install and maintain, at their own expense, the necessary ancillary equipment required to receive such data. Such access may require the installation by the Company of a different type of meter/recorder that shall allow multiple access, with the cost responsibility of such meter/recorder and installation to be borne by the customer and with the Company retaining sole control of the meter and responsibility for the installation and maintenance of the meter and compliance with applicable Commission regulations.

A schedule of meter upgrade charges shall be provided by the Company upon the request of the Customer or its authorized designee. The Company maintains a schedule of meter upgrade charges that covers standard metering options, and such schedule is available upon request.

(d) The Company shall perform meter readings in accordance with established reading cycles and current practices and provide relevant meter reading information to the ESCO. Information provided to an ESCO may be used solely by the ESCO for the purpose of billing the Customer.

9. Billing:

(a) Except as specified in Rule 11.F. of this Schedule, Consolidated Billing and Payment Processing, the Company shall bill a Customer only for the delivery of Electric Power Supply and other services provided by the Company. The ESCO is responsible for billing its Customer for the Electric Power Supply and other services the ESCO provides to the Customer.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

C. Customer Participation (Cont’d)

9. Billing (Cont’d)

(a) The Company bill will be issued to a Customer in accordance with established billing cycles and practices applicable to such Customer.

(b) A DC, ESCO or NYPA acting as an agent for Customers, is responsible for 1) obtaining and scheduling Electric Power Supply with the NYISO, and (2) complying with the provisions herein relating to Operational Issues (Scheduling, Balancing and Settlement) as specified in Rule 11.D.3 of this Schedule, with respect to its or a Customer’s Electric Power Supply requirements.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

C. Customer Participation (Cont'd)

10. Customer's Agent:

Participation by a Customer in General Retail Access Program shall be deemed an election by such customer for the ESCO selected by the Customer, to act as such customer's agent and attorney-in-fact for all matters relating to acquisition of Electric Power Supply, power scheduling, and transmission service (including, but not limited to, designation by such customer's ESCO or another ESCO to take responsibility for Operational Issues (Scheduling, Balancing and Settlement)), and Customers shall be bound by any determinations, decisions, understandings or agreements reached by such ESCO with respect to Operational Issues (Scheduling, Balancing and Settlement).

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

C. Customer Participation (Cont'd)

11. Provider of Last Resort ("POLR"):

(a) The Company shall be the POLR for those customers: (i) for whom competition is not a viable option, (ii) who choose not to participate in retail access, (iii) who terminate their agreements with an ESCO and fail to designate a substitute ESCO, (iv) who are acting as a DC, or (v) who are impacted by an ESCO's discontinuance of service.

(b) As a POLR, the Company shall:

i. Accept customers, subject to Commission consumer protection rules, and provide related customer services;

ii. Obtain and deliver Electric Power Supply for such customers, consistent with the then-current NYISO Tariffs and retail tariffs; and

iii. Provide for any programs, as approved by the Commission to assist low-income customers.

D. ESCO/DC Participation:

1. Eligibility Criteria:

To be eligible to participate in General Retail Access, an ESCO/DC must meet the requirements specified in the UBP Addendum.

2. ESCO/DC Requirements:

(a) ESCOs and DCs must sign and deliver to the Company an Operating Agreement.

(b) Scheduling of Deliveries:

The ESCO and DC are responsible for meeting the scheduling requirements of the NYISO as specified in the NYISO Transmission Tariffs and any applicable NYISO operating manuals. Electric Power Supply is defined as the electricity required to meet the Customer's needs, including energy, Energy Losses, Unaccounted for Energy, Capacity, Capacity Reserves, Capacity Losses, Ancillary Services, NTAC, transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, and Supply Adjustment Charge. The ESCO shall provide a copy of all schedules required by the NYISO to the Company in accordance with the Company's Electric Supplier Manual.

It is the responsibility of the ESCO/DC to schedule enough Electric Power Supply to account for Energy Losses and UFE associated with their load on the Company's distribution system. All retail load shall be categorized by the Company as primary or secondary load. Primary load applies to Customers taking service above 600 volts. Secondary load applies to Customers taking service at 600 volts or less. The Company shall notify the ESCO of the category applicable to each Customer's load. The loss factors are:

Primary Load:	4.68%
Secondary Load:	6.48%

(c) ESCOs must provide Home Energy Fair Practices Act (HEFPA) protections to residential customers, in compliance with the Commission's Order Relating to Implementation of Chapter 686 of the Laws of 2003 and Pro-Ration of Consolidated Bills, Case Nos. 99-M-0631 and 03-M-0017, issued June 20, 2003, together with the rules and regulations implementing the same, as may be revised, modified, amended, clarified, supplemented or superseded. Further information is available at the New York Public Service Commission's website (http://www.dps.ny.gov/hefpa.htm).

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

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GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

D. ESCO/DC Participation (Cont'd)

3. Operational Issues (Scheduling, Balancing and Settlement):

(a) The following applies to scheduling, balancing and settlement with the NYISO:

i. ESCOs/DCs will schedule Electric Power Supply directly with the NYISO.

ii. The Company will calculate customer load including the Company System Losses and UFE, by hour and combine accounts by ESCO/DC.

iii. The Company will communicate the hourly load calculations to the NYISO, in accordance with the NYISO's Billing Schedule requirements for true-ups.

iv. The NYISO will balance those hourly load calculations with the ESCO/DC bulk power deliveries, price the imbalance, and invoice or credit the ESCO/DC for the cost of the imbalance.

v. The NYISO will apply any additional applicable charges, as appropriate.

(b) When calculating wholesale hourly electric load allocations per ESCO/DC for reporting to the NYISO, the Company will not allocate any portion of the subzonal UFE to Hourly Pricing customer load. The load assigned to ESCO/DCs for Hourly Pricing customers will be the Hourly Pricing customer's metered hourly load plus the tariff voltage level / service class energy loss factor for that customer. All subzonal UFE will be allocated to ESCO/DCs based on each ESCO/DCs share of non-Hourly Pricing load in a given hour.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

Reserved for Future Use

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GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

E. Indemnity, Limitation on Liability, and Force Majeure:

1. Indemnification:

ESCO and DC, as applicable, agree to indemnify, defend and save harmless the Company from and against any and all liabilities, losses, damages, costs, expenses, causes of action, suits, judgments and claims, including, but not limited to, reasonable attorneys fees and the costs of investigation, (collectively "claims"), in connection with any action, suit or proceeding by or on behalf of any person, firm, corporation or other entity arising from, caused by or relating to the (i) curtailment or interruption of services to the ESCO or its Customers, or a DC, as applicable, due to causes beyond the control of the Company (including, without limiting the generality of the foregoing, executive or administrative rules or orders issued from time to time by State or Federal officers, commissions, boards or bodies having jurisdiction) or (ii) interruption, irregularity, failure or defective character of services to the ESCO, its Customers, or a DC, as applicable, due to causes beyond the control of the Company (including, without limiting the generality of the foregoing, executive or administrative rules or orders issued from time to time by State or Federal officers, commissions, boards or bodies having jurisdiction) or (iii) failure by ESCO or DC, as applicable, to perform any of the agreements, terms, covenants or conditions of General Retail Access Program to be performed by ESCO or DC, as applicable, or (iv) failure of ESCO to perform any agreement between ESCO and its Customers.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

E. Indemnity, Limitation on Liability, and Force Majeure (Cont'd)
2. Limitation on Liability:

The Company shall endeavor at all times to provide regular and uninterrupted service to the ESCO, its Customers, or a DC, as applicable, but in case the service shall be interrupted or irregular or defective or shall fail, from causes beyond the control of the Company (including, without limiting the generality of the foregoing, executive or administrative rules or orders issued from time to time by State or Federal officers, commissions, boards, or bodies having jurisdiction) or because of the ordinary negligence of the Company or its employees, contractors, subcontractors, servants or agents, the Company shall not be liable to the ESCO, its Customers, or a DC, as applicable, therefor.

Compliance with directives of the NYISO shall, without limitation by reason of specification, constitute a circumstance beyond the control of the Company for which the Company shall not be liable; provided, however, that the Company shall not be absolved from any liability to which it may otherwise be subject for gross negligence or intentional wrongdoing in the manner in which it carries out the NYISO instructions.

Without limiting the generality of the foregoing, the Company may, without liability therefor, interrupt, reduce or impair service to any ESCO, its Customers, or the DC, in the event of an emergency threatening the integrity of the Company's system, or any other systems with which it is directly or indirectly interconnected, if in the Company's sole judgment or that of the NYISO, such action shall prevent, alleviate or reduce the emergency condition, for such period of time as the Company or the NYISO deems necessary.

ESCOs serving Customers who require service which is uninterrupted, unreduced or unimpaired on a continuous basis should ensure that the Customers provide their own emergency or back-up capability.

The Company shall not be liable for any special, incidental, indirect, exemplary, punitive or consequential damages, including, but not limited to, lost profits, purchased power costs, or amounts owed by a DC or a Customer to its ESCO, suffered by an ESCO, its Customers, or a DC or to any other persons or entities caused by, arising from or related to the performance of or failure to perform any of the services or obligations of the Company under the General Retail Access Program as set forth in the Company's tariff or the Electric Supplier Manual, even if the Company has been advised of the possibility of such damages.

3. Force Majeure:

The Company and the ESCO/DC shall use due diligence in performing their obligations under this Tariff. Neither party shall be liable to the other in damages for any act, omission, occurrence, failure or delay of performance, damage, loss, injury or expense caused by any act of God, strike, lockout, act of the public enemy, act of terror, insurrection, civil unrest, war, blockade, riot, epidemic, landslide, extraordinary lightning, earthquake, fire, volcanic activity, extraordinary storm, flood, washout, explosion, accidental damage to or destruction of transmission or distribution facilities, equipment or machinery or electric lines or wires, or the seizure or appropriation of facilities or electricity by any governmental authority of competent jurisdiction or any other binding order of any court or public authority that the party has resisted by all reasonable legal means, or any other cause not reasonably within the control of the party asserting force majeure, and which such party is unable by the exercise of due diligence to avoid, prevent or overcome. A party's failure to avert or to settle a strike or other labor dispute shall not be deemed, within the meaning of this Rule, a matter reasonably within that party's control. Financial loss or other economic hardship shall in no event constitute force majeure hereunder.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

F. Consolidated Billing and Payment Processing

1. Description:
A Customer may elect Consolidated Billing and Payment Processing if offered by its ESCO, consistent with the Commission's Order Establishing Uniform Retail Access Billing and Payment Processing Practices, Case Nos. 99-M-0631 and 98-M-1343, issued May 18, 2001, as the same may be revised, modified, amended, clarified, supplemented or superseded. Further information is available at the New York Public Service Commission's website (http://www.dps.state.ny.us/ubr.htm). Company specific terms and conditions regarding Consolidated Billing and Payment Processing are detailed in the Billing Services Agreement and Electric Supplier Manual.

2. Customer Eligibility:
(a) Customers taking service under this Schedule, Service Classification Nos. 1, 2, 3, 4, 6, 7, 8, 9, 10, 11, 12, or 14; or P.S.C. No. 18 - Electricity, and not on summary billing, may elect a Consolidated Billing and Payment Processing option, consistent with the above-referenced PSC Order. Customers whose accounts are on summary billing must elect the dual billing option, as described in Section 9.L of the UBP addendum to this schedule.
(b) Customers taking service under the NYPA Program, Rule 34, are not eligible for Consolidated Billing and Payment Processing.

3. Bill Issuance Charge:
A Customer electing Consolidated Billing and Payment Processing pursuant to this Section shall not be billed the monthly Bill Issuance Charge for the electric and/or gas service for which Consolidated Billing and Payment Processing has been elected. All other customers receiving electric, gas, or combination service shall be billed one Bill Issuance Charge per bill.

4. Bill Processing Charges:
ESCOs shall be assessed a bill processing charge of $0.99 per bill for a Company rendered consolidated bill for those customers with electric-only or gas-only service. ESCOs shall be assessed a bill processing charge of $0.50 for electric service and $0.49 for gas service for a Company rendered consolidated bill for those customers with a combination of electric and gas service.

5. Purchase of ESCO Accounts Receivable Program (POR):
(a) ESCOs that elect the Company's consolidated billing option for all or a portion of their customers shall be required to sell their accounts receivable for such customers to the Company under the terms of the POR. ESCOs continue to have the right to issue their own bill using dual billing for all or a portion of their customers. Such ESCOs shall be precluded from participating in the POR for customers receiving dual billing.
(b) The POR obviates the need for the Company to prorate partial customer payments among ESCOs that are participating in the POR.

6. Account Separation Fee
In accordance with Section 9.C.4 of the UBP addendum to this schedule, an ESCO desiring to issue the Consolidated Bill for a customer with a Combination Account may request the Company to establish a separate account for the electric or gas service to be supplied by the ESCO. A fee of $5.00 shall be charged to the ESCO requesting establishment of a separate electric or gas account.

GENERAL INFORMATION

11. GENERAL RETAIL ACCESS (Cont'd)

G. Purchase of ESCO Accounts Receivable Program (POR)

In accordance with the Joint Proposal on Purchase of Accounts Receivable dated August 20, 2004 in Cases 03-E-0765 and 03-G-0766, as amended with the Joint Proposal dated July 14, 2010 in Cases 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718, and as further amended by the Joint Proposal dated February 19, 2016, in Cases 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286. The Company shall purchase accounts receivable at a discount and without recourse for commodity sales by ESCOs that provide commodity service in the Company's territory.

Eligibility Requirements:

ESCOs that elect the Company’s consolidated billing option for all or a portion of their customers shall be required to sell their accounts receivable for such customers to the Company under the terms of the POR. ESCOs continue to have the right to issue their own bill using dual billing for all or a portion of their customers. Such ESCOs shall be precluded from participating in the POR for customers receiving dual billing.

Purchase Price:

Electric and gas accounts receivable shall be purchased at a discount off face value of the ESCO receivable. The discount rate shall be sufficient to compensate the Company for its financial risk in purchasing electric and/or gas receivables, including, but not limited to, the level of the Company's uncollectibles and be comprised of the following components.

a) Commodity-related Uncollectible percentage based on total Company uncollectible costs for the most recent available twelve-month period divided by the sum of the total retail, retail access, and purchased ESCO receivables revenue for the same twelve-month period;

b) Financial Risk Adder set at 20% of the applicable uncollectible percentage;

c) Commodity-related credit and collections and call center percentage.

Discount rates shall be adjusted each year to reflect the Company’s most recent twelve-month experience for uncollectible expense. Additionally, the credit and collections and call center allocation included in the discount rate shall be reconciled annually, with any under- or over-collections included in the following years discount rate.

Beginning with the statement to be effective May 1, 2017, a POR Discount (DISC) Statement setting forth the electric discount and the gas discount shall be filed with the Public Service Commission 60 days prior to the May 1 effective date of each annual update.

Payments:

Payments to ESCOs will be made, via wire transfer, 20 days after consolidated bills are issued, and shall continue throughout the billing cycle.

Other Considerations:

The POR shall be subject to modifications based upon Commission orders, rules, and regulations applicable to retail access, including, but not limited to, the Uniform Business Practices, proration of customer payments under a single bill, and provisions of Home Energy Fair Practices Act. The POR obviates the need for the Company to prorate partial customer payments among ESCOs that are participating in the POR.

GENERAL INFORMATION
11. GENERAL RETAIL ACCESS (Cont'd)

H. Community Choice Aggregation (CCA)

1. A CCA Program allows municipalities (villages, towns and cities) to aggregate the usage of eligible CCA customers (residential and small non-residential customers) within a defined jurisdiction in order to secure an alternative energy supply contract on a community-wide basis.

   a. In accordance with the Orders issued April 21, 2016, December 14, 2017, and January 19, 2023, in Case 14-M-0224, before requesting customer data from the utility for participation in a CCA Program, the municipality or their designee (CCA Administrator or ESCO):
      i. must sign a Data Security Agreement acceptable to the Company, and
      ii. must have an approved implementation plan and certification of local authorization approved by the NYS PSC.

   b. Upon fulfilling the requirements in Rule 1.a, the Company will provide the following information to the municipality or their designee in accordance with the terms stated herein.
      i. Aggregated customer data, including the number of customers by service class, the meter read cycle, the aggregated peak demand (kW) by month for the past 12 months by service class if applicable, and the aggregated energy (kWh) by month for the past 12 months by service class. This information will be provided to the municipality or CCA Administrator within twenty days of a request.

      ii. After each municipality has entered into a CCA contract with an ESCO, the Company shall transfer customer-specific data to the municipality or CCA Administrator within five days of receipt of a request to support the mailing of opt-out notices. The data shall include all customers in the municipality eligible for opt-out treatment based on the CCA and the requirements of the April 21, 2016, and January 19, 2023, Orders issued in Case 14-M-0224. The data should include:
         (1) Customer of record’s name
         (2) Mailing Address
         (3) Primary Language (if available from the Company’s billing system)
         (4) Any customer-specific alternate billing name and address
         (5) Bill cycle and period code
         (6) Tax-exempt Status
         (7) Net metered/VDER/solar account indicator
         (8) Dual-meter indicator

      iii. After the opt-out process has been completed, the Company shall transfer account numbers for eligible customers that did not opt-out to the ESCO providing service within five days of receipt of a list of customers that opted out. These account numbers may be transmitted via electronic mail in secured, encrypted spreadsheets, through access to a secure website, or through other secure methods of transfer.

      iv. Upon request by the municipality or CCA Administrator the Company will transfer the customer data in (b) to the requestor within five days of the request for newly eligible customers that became customers of the Company since the last eligible customer list was provided and were not on a previous eligible for out-out list. The Company will distinguish between new accounts and customers that are now opt-out eligible for other reasons. After the opt-out process has been completed for those customers, the Company will provide account numbers for customers that did not opt-out as described in (c). These eligible customer update lists will be provided without charge.

2. Dispute Resolution
   For disputes arising in relation to a CCA, the Company, CCA Administrators, and Energy Service Entities may utilize the dispute resolution process specified in the January 19, 2023, Order issued in Case No. 14-M-0224.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS

A. Supply Service Options

The Company shall offer a Retail Access choice and a Non-Retail Access choice, as described below. These Supply Service Options are available to all customers, except as noted.

1. ESCO Supply Service (ESS):

This Retail Access choice includes fixed charges for the Company delivery service, a Transition Charge as described in Rule 12.B. and a Bill Issuance Charge, if applicable. An ESCO provides Electric Power Supply to the customer.

2. RG&E Supply Service (RSS):

This Non-Retail Access choice includes fixed charges for the Company delivery service, a Transition Charge as described in Section 12.B, a Bill Issuance Charge, a fluctuating commodity charge for electricity supplied by the Company, and a Merchant Function Charge (MFC) as described in Rule 12.D. The commodity charge fluctuates with the market price of electricity and consists of energy, capacity, capacity reserves, losses, unaccounted for energy, ancillary services and a NYPA Transmission Access Charge (NTAC), transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, and Supply Adjustment Charge.

a. The commodity charge for customers billed under Service Classification Nos. 1, 2, and 6 and customers within P.S.C. No. 18 - Street Lighting, shall reflect a managed mix of supply resources.
b. The commodity charge for customers billed under Service Classification Nos. 3, 4, 7, and 9, shall reflect the market price of electricity.

3. Hourly Pricing:

This choice is for customers billed at a demand metered rates, which includes non-residential Service Classification Nos. 8 and 14. Customers may take service with an ESCO or with the Company under this choice.

a. For customers taking service with an ESCO, such customers shall be responsible for fixed charges for the Company delivery, a Transition Charge as described in Rule 12.B.
b. For customers taking service with the Company, such customers shall be responsible for fixed charges for the Company delivery, a Transition Charge as described in Section 12.B., a commodity charge for electricity supply that fluctuates hourly with the market price (including losses, unaccounted for energy, capacity and capacity reserve), a Merchant Function Charge (MFC) as described in Rule 12.D., transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, and Supply Adjustment Charge.

B. Transition Charge

Components of the Transition Charge:

The Transition Charge, as shown on a customer's bill, shall be the sum of the following components. Each component shall identify if the costs are recovered on a volumetric basis or on a demand-billed basis. The Company shall file a Statement for each component with the Public Service Commission.

GENERAL INFORMATION
12. SUPPLY SERVICE OPTIONS (Cont'd)

B. Transition Charge (Cont'd)
Components of the Transition Charge (Cont'd):

1. Non-Bypassable Charge ("NBC")
   The NBC is a per kWh charge that shall recover specific generation and purchased power-related costs net of credits for the value of generation and purchased power controlled by the Company.

   a. The costs associated with the NBC shall be allocated as described here and collected by all customers taking electric delivery service. Listed below are the costs associated with the NBC which will be collected by service classifications as follows:
      i. Variable costs of the Company owned generation
      ii. The value of the output of the Company-owned generation;
      iii. Monthly payments received by the Company from NYPA under the Recharge New York Residential Consumer Discount Program (New York Public Authorities Law § 1005(13-b));
      iv. The net value of NYPA and Ginna purchased power contracts. The net value shall be based on a forecast of the output and contract costs, and market prices;
      v. Any Public Service Commission approved adjustments.
      vi. Any over- or under- collections from reconciliation of the Residential Agricultural Discount, as set forth in Rule 4.L.6 shall be included in a subsequent monthly NBC for the residential customer classes. Application of the Residential Agricultural Discount reconciliation amounts to the NBC shall not cause the NBC to reduce the delivery bill to less than zero
      vii. Any remaining over- or under-collections from the Retail Access Surcharge;
      viii. Transmission-related costs and revenues,
      ix. Credits provided to customers receiving the Standby Reliability Credit, as set forth in Service Classification 14, Special Provision (f), will be recovered through the NBC.
      x. Credits provided to residential customers pursuant to Service Classification No. 4 Special Provision 11.C, Price Guarantee, shall be recovered through the NBC applicable to S.C. Nos. 1 and 4.
      xi. Effective December 1, 2011, pursuant to the Order in Case 01-E-0011, issued and effective October 26, 2001, the purchased power contract with the new owner of the nuclear generating plant previously co-owned by the Company shall convert to a Revenue Sharing Agreement (RSA).

          Any applicable payments received under the RSA for a contract quarter shall be refunded to customers beginning in the calendar month following the month in which the payment is received. Such payments shall be refunded to customers over three consecutive months. An allowance for carrying charges at the other customer deposit rate in effect at the time of the payment shall also be included.

   b. The NBC shall be set monthly based on a forecast and subject to a monthly true-up for all components based on the actual after-the-fact costs and load subject to the NBC.

   c. All service classes shall pay the charge on a volumetric basis Residential customer classes shall also receive the benefits, if any, of NYPA purchased power and monthly payments received by the Company from NYPA under the Recharge New York Residential Consumer Discount Program (New York Public Authorities Law § 1005(13-b)), consistent with any Company contracts with NYPA for such purchased power and/or monthly payments.

   d. All items collected through the NBC shall be symmetrically reconciled and trued-up monthly in a competitively neutral manner. The credits or charges related to the reconciliation shall be included in a subsequent monthly NBC.

      A Non-Bypassable Charge Statement setting forth the NBC shall be filed with the Public Service Commission on not less than one day's notice. Such statement can be found at the end of this Schedule.

GENERAL INFORMATION
12. SUPPLY SERVICE OPTIONS (Cont'd)

B. Transition Charge (Cont'd)
Components of the Transition Charge (Cont'd):

2. Value of Distributed Energy Resources ("VDER") Value Stack Credits Statement
   a. The following costs associated with Value Stack and Wholesale Value Stack, as applicable, paid by the Company pursuant to Rule 26.B Value Stack and Rule 26.C.2 Wholesale Value Stack, shall be allocated and collected by service classification as follows:
      i. Capacity Value [Market Value]: allocated to service classes based on how the Company allocates ICAP;
         a. Costs associated with the Capacity Value [Market Value and Out of Market Value] shall not be recovered from Hourly Pricing customers
      ii. Capacity Value [Out of Market Value], Environmental Value [Out of Market Value], and Market Transition Credit: all delivery customers, allocated to service classes based on the composition of subscribers who receive benefits in proportion to the benefits received;
         a. The Environmental Value [Out of Market Value] shall be recovered through the Transition Charge through December 31, 2024. Beginning January 1, 2025, the full cost of the Environmental Component (Rule 26.B.6.iii), including the Environmental Value [Out of Market Value], shall be recovered through the Supply Adjustment Charge.

      iii. Demand Reduction Value (DRV) and Locational System Relief Value (LSRV): all delivery customers on a voltage level basis; allocated to service class by voltage level based on appropriate T&D demand allocators. The DRV and LSRV shall be collected from demand-billed customers on a per-kW basis.

   A Value of Distributed Energy Resources Cost Recovery ("VDER-CR") Statement setting forth the VDER rates shall be filed with the Commission on not less one day's notice. Such statement can be found at the end of this Schedule.

3. Distribution Load Relief Program
   a. The costs associated with Rule 4.R., Distribution Load Relief Program; Rule 4.S., Commercial System Relief Program; and Rule 4.T., Direct Load Control Program, shall be allocated as described in those Rules and collected by service classification as follows:
      i. non-demand billed customers on a per-kWh basis;
      ii. demand-billed customers on a per-kW basis.

   A Dynamic Load Management ("DLM") Statement setting forth the cost values for the Distribution Load Relief Program, by service classification, shall be updated annually and filed with the Public Service Commission on not less than one days' notice. Such statement can be found at the end of this Schedule.

4. Rate Adjustment Mechanism ("RAM")
   a. The cost associated with Rule 24. Rate Adjustment Mechanism, shall be allocated as described in that Rule and collected by service classifications as follows:
      i. non-demand billed customers on a per-kWh basis;
      ii. demand-billed customers on a per-kW basis.

   A Rate Adjustment Mechanism Statement setting forth the RAM rates shall be filed with the Commission on not less 30 days' notice to be effective July 1. Such statement can be found at the end of this Schedule.

5. Non-Wire Alternatives ("NWA")
   a. The cost associated with Rule 32, Non-Wires Alternatives, shall be allocated as described in that Rule and collected by service classification as follows:
      i. non-demand billed customers on a per-kWh basis;
      ii. demand-billed customers on a per-kW basis.

A Non-Wires Alternatives Statement setting for the NWA rates shall be filed with the Commission on not less than 30 days' notice. Such statement can be found at the end of this Schedule.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

B. Transition Charge (Cont'd)
Components of the Transition Charge (Cont'd):

6. Earnings Adjustment Mechanism ("EAM")
The cost associated with Rule 4.K, Earnings Adjustment Mechanism, shall be allocated as described in that Rule and collected by service classification as follows:
   i. non-demand billed customers on a per-kWh basis;
   ii. demand-billed customers on a per-kW basis.

   An Earnings Adjustment Mechanism Statement setting for the EAM rates shall be filed with the Commission on not less than 30 days' notice. Such statement can be found at the end of this Schedule.

7. Electric Vehicle ("EV") Make Ready Surcharge
The cost associated with Rule 33, Electric Vehicle ("EV") Make Ready Surcharge, shall be allocated as described in that Rule and collected by service classification as follows:
   i. non-demand billed customers on a per-kWh basis;
   ii. demand-billed customers on a per-kW basis.

   An EV Make Ready ("EVMR") Statement setting for the rates shall be filed with the Commission on not less than 15 days' notice. Such statement can be found at the end of this Schedule.

8. Late Payment Charge and Other Waived Fees ("LPCO") Surcharge
The cost associated with Rule 4.K, Late Payment Charge and Other Waived Fees ("LPCO") Surcharge, shall be allocated as described in that Rule and collected by service classifications as follows:
   i. non-demand billed customers on a per-kWh basis;
   ii. demand-billed customers on a per-kW basis.
   iii. Standby on an As-Used demand basis.

   A Statement of Other Charges and Adjustments ("OTH") setting forth the LPCO Surcharge rates shall be filed with the Commission on not less than three (3) days' prior to the effective date. Such statement can be found at the end of this Schedule.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

C. Calculation of the Commodity Charge

1. S.C. Nos. 1, 2, 6 and P.S.C. No. 18 Street Lighting

The charge for Electric Power Supply provided by RG&E shall fluctuate with the market price of electricity and shall include the following components; Energy, Energy Losses, Unaccounted For Energy ("UFE"), Capacity, Capacity Reserves, Capacity Losses, Ancillary Services/NTAC, transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, hedge adjustment and a Supply Adjustment Charge. The methodology for calculating the Energy and Capacity components of the charge for Electric Power Supply is as follows:

Energy Component:
For each day of the customer's billing cycle, a daily average value of market supply is derived from forward trading market prices of electricity for the region and previous true-ups, weighted to reflect hourly usage based on service classification load profiles for the calendar month and day-type (Weekday, Saturday or Sunday). Separate calculations shall be made for each metered time period for the Customer's individual Service Classification.

The daily load weighted market price of energy shall be adjusted to reflect losses. These daily average market supply values are used in conjunction with the service classification profile to develop a weighted average value of market supply for each metered time period within the Customer's specific billing period. The weighted average of market supply is multiplied by the Customer's metered kWh usage for each metered time period to determine the value of market supply.

Capacity Component:
The Capacity component is calculated using the market-clearing price of capacity converted to $/kWh as determined from the NYISO's monthly and spot capacity auctions. The capacity price shall also include capacity losses and reserves. The service class profile shall be used to determine the customer's capacity responsibility of state-wide system peak demand. A new capacity responsibility amount shall be effective each May 1st. The service class profile contribution to the system peak demand may need to be adjusted for a growth factor.

Capacity Charge = UCAP Charge + Demand Curve Reserve Charge

UCAP Charge = (UCAPreq * (1 + Reservereq)* Pricemonthlyauc)

UCAPreq = The demand for the customer's service class that occurred at the time of the New York system peak of the prior year, grossed up for losses and a growth factor.

Reservereq = Additional reserve requirement as required by NYISO.
Pricemonthlyauc = Monthly NYISO auction price.

Demand Curve Reserve Charge = (UCAPreq * DemandCurveReservereq)* Pricespotauc)
UCAPreq = Described above.
DemandCurveReservereq = Allocation of additional capacity requirement as required by the NYISO's demand curve.
Pricespotauc = Monthly NYISO SPOT auction price.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

C. Calculation of the Commodity Charge (Cont'd)

1. S.C. Nos. 1, 2, 6 and P.S.C. No. 18 Street Lighting (Cont'd)

Ancillary Services/NYPA Transmission Adjustment Charge (NTAC) Component:
The ancillary services/NTAC shall be forecasted each month and included in the supply price and subsequently reconciled.

Hedge Adjustment:
The hedge adjustment shall pass through to customers the impact of any hedge position entered into on behalf of such customers.

NYISO Related Transmission Charges:
Transmission project costs allocated to the Company under the NYISO tariff as approved by FERC.

Supply Adjustment Charge Component:
Unaccounted For Energy, Renewable Energy Credits (RECs), Zero Emissions Credits (ZECs), and if applicable, Alternative Compliance Payment (ACP), Offshore Wind Renewable Energy Credits (ORECs), costs the Company has paid for the Value Stack Energy Component not reflected in the price for the Energy Component and the Market Value of the Environmental component of the Value Stack pursuant to Rule 26.B., costs billed to the Company by NYSERDA for the bulk energy storage program, and all costs incurred related to supply shall be reconciled and recovered or refunded through a subsequent Supply Adjustment Charge incorporated in the supply charge.

Beginning January 1, 2025, the full cost of the Environmental Component (Rule 26.B.6.iii), including the Out of Market Value, shall be included in the Supply Adjustment Charge.

2. Non-Hourly Pricing S.C. Nos. 3, 4, 7, 9

The charge for Electric Power Supply provided by the Company shall fluctuate with the market price of electricity and shall include the following components: Energy, Energy Losses, Unaccounted for Energy ("UFE"), Capacity, Capacity Reserves, Capacity Losses, ancillary services, NTAC, and a Supply Adjustment Charge. The methodology for calculating the Energy and Capacity components of the charge for Electric Power Supply is as follows:

Energy Component:
For each day of the customer's billing cycle, a daily average value of market supply is derived from the day ahead NYISO posted Locational Based Marginal Prices (LBMP) of electricity for the region weighted to reflect hourly usage based on service classification load profiles for the calendar month and day-type (Weekday, Saturday or Sunday). Separate calculations shall be made for each metered time period for the Customer's individual Service Classification.

The daily load weighted market price of energy shall be adjusted to reflect losses and Unaccounted For Energy. These daily average market supply values are used in conjunction with the service classification profile to develop a weighted average value of market supply for each metered time period within the Customer's specific billing period. The weighted average value of market supply is multiplied by the Customer's metered kWh usage for each metered time period to determine the value of market supply.

Capacity Component:
The Capacity component is calculated using the market-clearing price of capacity in $/kWh as determined from the NYISO's monthly capacity auction price. The Capacity Component shall be revised in accordance with each monthly UCAP auction held by the NYISO. The capacity price shall also include capacity losses and reserves based on the NYISO monthly and spot capacity auctions. The service class profile shall be used to determine the customer's capacity responsibility of state-wide system peak demand. A new capacity responsibility amount shall be effective each May 1st. The service class profile contribution to the system peak demand may need to be adjusted for a growth factor. The cost of the capacity component shall be applied to On-Peak hours only.

Capacity Charge = UCAP Charge + Demand Curve Reserve Charge

UCAP Charge = ($UCAP_{req}$ * (1 + $Reserve_{req}$)* $Price_{monthlyauc}$)

$UCAP_{req}$ = The demand for the customer's service class that occurred at the time of the New York system peak of the prior year, grossed up for losses and a growth factor.

$Reserve_{req}$ = Additional reserve requirement as required by NYISO.
$Price_{monthlyauc}$ = Monthly NYISO auction price.

GENERAL INFORMATION
12. SUPPLY SERVICE OPTIONS (Cont'd)

C. Calculation of the Commodity Charge (Cont'd)
2. Non-Hourly Pricing S.C. Nos. 3, 4, 7, 9 (Cont'd)

Capacity Component: (Cont'd)
Demand Curve Reserve Charge = ($UCAP_{req}$ * $DemandCurveReserve_{req}$)* $Price_{spotauc}$)
$UCAP_{req}$ = Described above.
$DemandCurveReserve_{req}$ = Allocation of additional capacity requirement as required by the NYISO's demand curve.
$Price_{spotauc}$ = Monthly NYISO SPOT auction price.
Ancillary Services/NYPA Transmission Adjustment Charge (NTAC) Component:
The ancillary services/NTAC shall be forecasted each month and included in the supply price and subsequently reconciled.

NYISO Related Transmission Charges:
Transmission project costs allocated to the Company under the NYISO tariff as approved by FERC.

Supply Adjustment Charge Component:
Unaccounted For Energy, Renewable Energy Credits (RECs) and Zero Emissions Credits (ZECs) costs and if applicable, Alternative Compliance Payment (ACP), Offshore Wind Renewable Energy Credits (ORECs), costs the Company has paid for the Value Stack Energy Component not reflected in the price for the Energy Component and the Market Value of the Environmental component of the Value Stack pursuant to Rule 26.B., costs billed to the Company by NYSERDA for the bulk energy storage program, and all costs incurred related to supply shall be reconciled and recovered or refunded through a subsequent Supply Adjustment Charge incorporated in the supply charge.

Beginning January 1, 2025, the full cost of the Environmental Component (Rule 26.B.6.iii), including the Out of Market Value, shall be included in the Supply Adjustment Charge.

3. Hourly Pricing S.C. Nos. 8 and 14 (Mandatory and Voluntary):
The charge for Electric Power Supply provided by the Company shall fluctuate with the market price of electricity and shall include the following components: Energy, Energy Losses, Unaccounted for Energy, Capacity, Capacity Reserves, Capacity Losses, ancillary services, NTAC, transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, and Supply Adjustment Charge.

Energy Component:
Customers served under this provision shall be charged for the energy component of supply based on their hourly metered usage and the hourly supply cost. The electricity supply charge is equal to the sum of the hourly metered usage multiplied by the NYISO Day-Ahead Market (DAM) Location Based Marginal Price (LBMP) for the Genesee Zone adjusted for losses, ancillary services, NTAC, transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, and Supply Adjustment Charge. Capacity charges shall also be based on interval meter data. The DAM LBMP prices shall be the initial published DAM LBMP prices acquired by the Company. The customer's bill shall not be recalculated if such prices are modified by the NYISO at a later date.

Ld = Distribution loss factor. All customers shall be categorized as primary or secondary load. Primary load applies to customers taking service above 600 volts. Secondary load applies to customers taking service at 600 volts or less. RG&E shall notify the customer of the category applicable to it. The loss factors are:

Primary Load: 4.68%
Secondary Load 6.48%

Capacity Component:
The capacity and capacity reserves are specific to the customer. When hourly data is not available the appropriate service class profile shall be used to determine the customer's capacity responsibility. A new capacity responsibility amount shall be established for each customer each April, to be effective on or after May 1. Customers new to Hourly Pricing that begin the service prior to April shall be assigned their capacity responsibility based on their service class profile until the first April where the required hourly data is available.

GENERAL INFORMATION
12. SUPPLY SERVICE OPTIONS (Cont'd)

C. Calculation of the Commodity Charge (Cont'd)

3. Hourly Pricing S.C. Nos. 8 and 14 (Mandatory and Voluntary): (Cont'd)

Capacity Component: (Cont'd)

Capacity Charge = UCAP Charge + Demand Curve Reserve Charge

UCAP Charge = $((((UCAP_{req} * 1/(1-L_d)) * (1 + Reserve_{req}))* Price_{monthlyauc})$

$UCAP_{req}$ = The customer specific demand that occurred at the time of the New York system peak of the prior year. When the customer specific information is not available the appropriate service class profile information will be used.

L_d - Distribution loss factor. Described above

$Reserve_{req}$ = Additional reserve requirement as required by NYISO

$Price_{monthlyauc}$ = Monthly NYISO auction price

Demand Curve Reserve Charge = $((((UCAP_{req} * 1/(1-L_d)) * \text{Demand Curve Reserve Charge}_{req}))* Price_{spotauc})$

$UCAP_{req}$ - Described above

L_d - Described above

Demand Curve $Reserve_{req}$ = Allocation of additional capacity requirement as required by the NYISO's demand curve

$Price_{spotauc}$ = Monthly NYISO capacity spot market price.

Ancillary Services/NYPA Transmission Adjustment Charge (NTAC) Component:
The ancillary services/NTAC shall be forecasted each month and included in the supply price and subsequently reconciled.

NYISO Related Transmission Charges:
Transmission project costs allocated to the Company under the NYISO tariff as approved by FERC.

Supply Adjustment Charge Component:
Unaccounted For Energy, Renewable Energy Credits (RECs) and Zero Emissions Credits (ZECs) costs and if applicable, Alternative Compliance Payment (ACP), Offshore Wind Renewable Energy Credits (ORECs), costs the Company has paid for the Value Stack Energy Component not reflected in the price for the Energy Component and the Market Value of the Environmental component of the Value Stack pursuant to Rule 26.B., costs billed to the Company by NYSERDA for the bulk energy storage program, and all costs incurred related to supply shall be reconciled and recovered or refunded through a subsequent Supply Adjustment Charge incorporated in the supply charge.

Beginning January 1, 2025, the full cost of the Environmental Component (Rule 26.B.6.iii), including the Out of Market Value, shall be included in the Supply Adjustment Charge

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

D. Merchant Function Charge (MFC):

The MFC shall be applicable to only those customers taking supply service from the Company (*i.e.*, RSS and Hourly Pricing) and is set forth in a statement at the end of this Schedule (P.S.C. No. 19 – Electricity). A separate MFC shall be calculated for Non-demand Billed (Hedged) (S.C. Nos. 1, 2, 6 and street lighting), Non-demand Billed (Non-hedged) (S.C. No. 4) and Demand Billed (S.C. Nos. 3, 7, 8, 9, 10, 11, & 14) customers. For Service Classification Nos. 10, 11, and 14, the customer's otherwise applicable service classification shall determine the applicable MFC.

1. The MFC shall include the following rate components as described in the Joint Proposal dated July 14, 2010 in Case Nos. 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718, and as further amended by the Joint Proposal dated February 19, 2016, in Cases 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286.
   a. Commodity-related Uncollectible Costs
   b. Commodity-related Credit and Collections and Call Center costs;
   c. Commodity-related Administrative costs;
   d. Cash Working Capital on Purchased Power costs and
   e. Cash Working Capital on Commodity Hedge Margin costs.
   f. Prior Period Reconciliation
2. The MFC components shall be updated and reconciled as stated below in accordance with the Joint Proposal dated July 14, 2010 in Case Nos. 09-E-0715, 09-G-0716, 09-E-0717, and 09-G-0718, and as further amended by the Joint Proposal dated February 19, 2016, in Cases 15-E-0283, 15-G-0284, 15-E-0285, and 15-G-0286.
   a. Commodity-related Uncollectible Costs
      - The commodity related uncollectible percentage rate shall be reset annually based on the most recent available 12-month period of actual uncollectibles
      - The commodity-related uncollectible component of the MFC shall be calculated each month by multiplying the uncollectible percentage rate for each of the groups described above by the associated monthly electric supply cost.
   b. Commodity-related Credit and Collections and Call Center costs
      - The Credit and Collections and Call Center Cost Component shall be reconciled annually for differences in actual versus design sales only. The unit rate shall be reset annually based on recent sales forecasts.
   c. Commodity-related Administrative costs
      - The Administrative Component shall be reconciled annually for differences in actual versus design sales only. The unit rate shall be reset annually based on recent sales forecasts.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

D. Merchant Function Charge (MFC) (Cont'd):

d) Cash Working Capital on Purchased Power costs

- If the New York Independent System Operator starts weekly billing, the electric MFC shall include a component for Cash Working Capital on Purchase Power.
- Working Capital on Purchase Power shall be calculated based on the Companies' pre-tax rate of return.
- The Companies shall reconcile the Working Capital on Purchased Power to actual applicable costs. This component shall be updated annually to reflect actual costs from the most recently available 12-month period and the most recent sales forecast.

e) Cash Working Capital on Commodity Hedge Margin costs

- The cash working capital on Commodity Hedge cost component shall be based on the Companies' pre-tax rate of return and shall be reconciled to actual costs annually. Additionally, this component shall be updated annually to reflect actual costs from the most recently available twelve month period and the most recent sales forecast.

E. Customer Eligibility Criteria

1. Customers Applying for Service:

If a customer applying for service has not elected a Supply Service option by the time of billing, RG&E shall bill the customer at the appropriate default option as explained in 12.E. When a customer contacts RG&E with their choice, that Supply Service option shall be applicable to usage on and after the next regularly-scheduled estimated or actual meter reading date after such contact.

2. Incentive Rate Customers:

Customers receiving an Economic Incentive may select a Supply Service option as specified in the applicable Special Provision for Economic Incentives of the respective service classification. The customer must choose the same Supply Service option for their entire load.

3. NYPA Customers

Customers who receive a portion of their Electric Power Supply from NYPA, (Expansion, HLFM, Replacement or Preservation Power, Recharge NY Power, WNY), with Standard Load (non-NYPA load), shall be permitted to take service under any Supply Service option for their Standard Load. The NYPA load shall continue to be billed in accordance with Rule 4.L.5 or the Special Provision of Service Classification Nos. 3, 7 and 8. If the NYPA allocation expires or is terminated, the Supply Service option for that load shall be the same option the customer selected for the Standard Load (non-NYPA load).

4. Service Classification No. 10 ("S.C. No. 10") Contracts:

A customer taking service under a special contract, or receiving an incentive or discounted rate which by its terms would preclude eligibility, may not select an electricity supply pricing option. A customer may select an electricity supply service option upon expiration of such contract..

5. Service Classification No. 14 ("S.C. No. 14") Standby Service:

A customer taking service under S.C. 14 is eligible to select a Supply Service option as follows:

a. "OASC"

A customer taking service under S.C. No. 14 as an Existing Customer having elected the Phase-In, or as a Designated Technology Customer having elected the one-time exemption (both as defined in S.C. No. 14), shall be billed at the otherwise applicable service classification ("OASC") rate. Such customers are eligible for: 1) the RG&E Supply Service (RSS), unless the customer is required to participate in mandatory Hourly Pricing or voluntarily elects Hourly Pricing, or 2) the ESCO Supply Service (ESS).

b. S.C. No. 14:

A customer taking service under S.C. No. 14, shall be billed at the S.C. No. 14 rates set forth under the section "RATES". Such customers are eligible for: 1) RG&E Supply Service (RSS), unless the customer is required to participate in mandatory Hourly Pricing or voluntarily elects Hourly Pricing, or 2) the ESCO Supply Service (ESS).

6. Hourly Pricing:

Hourly Pricing is mandatory for certain non-residential demand billed customers in Service Classification Nos. 8 and 14. A customer billed at an Hourly Pricing rate is eligible to select a Supply Service option as defined in Rule 12.A.3.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

F. Default Process

1. Default Process:

If a customer applying for service has not elected a Supply Service option, the Company shall bill the customer under the RG&E Supply Service option or Hourly Pricing, as appropriate.

G. Changing Supply Service Options

1. Switching Rules:

a. A customer can switch to and from retail access at any time subject to the requirements set forth in the General Information Section 11 General Retail Access – Multi Retailer Model and the Uniform Business Practices, and as detailed below:

1) ESCO Supply Service (ESS)
A customer taking service under the ESS option may switch to the RG&E Supply Service (RSS).

2) RG&E Supply Service (RSS)
A customer taking service under the RSS may switch to the ESCO Supply Service (ESS) unless otherwise ineligible as described in Rule 12.D.

3) Hourly Pricing
A customer mandatorily participating in Hourly Pricing, who is taking service under the ESS option, may only switch to Hourly Pricing with RG&E under the RSS option

A customer mandatorily participating in Hourly Pricing, who is taking service under the RSS option, may switch to the ESS option.

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

G. Changing Supply Service Options (Cont'd)

2. Process for Changing to a Retail Access Supply Service Option

To effectuate the switch to Retail Access, the customer's ESCO must contact the Company to submit the customer's Retail Access enrollment information as described in General Information Section 11 Retail Access – Multi Retailer Model. Upon the Company's receipt of notice that the customer is enrolling in Retail Access, the Company shall notify the customer of such enrollment by sending the customer a letter.

3. Process for Changing to a Non-Retail Access Supply Option

A customer that is participating in Retail Access who would like to switch to the Company for their Electric Power Supply (Non-Retail Access) may do so by first contacting its ESCO to discontinue Retail Access service.

Alternatively, a customer may switch to the Company for its Electric Power Supply by calling the Company, not less than five business days prior to their next scheduled or Special Meter Reading date.

Upon the Company's receipt of the ESCO's notice that the customer is canceling Retail Access, the Company shall notify the customer of such cancellation by sending the customer a letter. The customer shall be placed on the RSS option effective with the switch date.

4. ESCO Discontinuance of Sales to an Individual Customer

If an ESCO cancels a customer's Retail Access service, such ESCO must follow the procedures set forth in the UBP Addendum to this Schedule. Upon receipt of the notice of discontinuance from the ESCO, the Company shall verify this request with the customer by sending a letter to the customer. The customer may choose another ESCO or return to the RSS Non-Retail Access option. The customer shall be placed on the RSS option effective with the switch date if a new Retail Access enrollment has not been completed by the switch date.

5. Service Classification No. 10 ("SC10") Contract Expiration

a. A customer required to take mandatory Hourly Pricing:
A customer taking service under SC10, who would otherwise qualify for mandatory Hourly Pricing, shall be billed at Hourly Pricing rates upon expiration of their SC10 contract, unless a Retail Access enrollment is received from an ESCO at least five business days prior to the contract end date. If such retail access enrollment has been received, the customer shall be billed at the ESCO Supply Service (ESS) option effective with the contract end date meter reading.

b. Customers not required to take mandatory Hourly Pricing:
If the customer is not required to be served at Hourly Pricing, upon expiration of their SC10 contract, the customer would be eligible to select a Supply Service Option described in Section 12.A. If the customer does not enroll in a Supply Service option, and no retail access enrollment has been received from an ESCO at least five business days prior to the contract end date, the customer shall be billed at the Company Supply Service (RSS) option effective with the contract end date meter reading.

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

Reserved for Future Use

GENERAL INFORMATION

12. SUPPLY SERVICE OPTIONS (Cont'd)

Reserved for Future Use

GENERAL INFORMATION

13. Distributed Energy Resources

The following requirements are applicable to all customers that install an eligible Distributed Energy Resource (DER) as described for each program. A customer with a DER shall take service under the otherwise applicable standard service classification and shall be exempt from Standby Service.

A. Interconnection
   a. Interconnection Requirements
      i. Interconnection requirements are established in General Rule No. 10, Distributed Energy Resource Interconnection Requirements.
      ii. Applicable to any customer installing a Distributed Energy Resource (DER) unit (e.g. distributed generation or energy storage system) 5 MW or less, connected in parallel with the Company's utility distribution system.
      iii. These requirements are not applicable to a DER unit which is not connected to the Company's distribution grid.
      iv. A customer that is installing DER is required to comply with the Standardized Interconnection Requirements (SIR), including the standard applications and contracts, are set forth within Addendum-SIR to this Schedule.

B. Uniform Business Practices – Distributed Energy Resources Providers

The rules applicable to DER Suppliers are contained in the Addendum, UBP-DERS, attached to this Schedule, which are incorporated herein.

The UBP-DERS contains provisions applicable to all DER Suppliers as well as provisions applicable only to Community DG providers (pursuant to Rule 23) and on-site mass market DG providers.

C. Metering Requirements applicable
   a. A Net Metered Generation Facility that has completed Step 8 of the SIR Addendum-SIR or has installed Net Metered Generation Facility on or prior to March 9, 2017 ("Existing"), the Company shall install metering appropriate for the customer's service classification that enables the Company to measure the electricity delivered to the customer and measure the electricity supplied by the customer to the Company.
   b. A Net Metered Generation Facility that does not meet the requirements in a. above, or the Host Account of a project that is participating in Remote Crediting: the Company shall install metering capable of recording net hourly consumption and injection for a customer. The customer shall be responsible for the cost of the meter, the installation, the communication to the meter and any additional costs.
   c. Where the Company determines that a second meter should be installed, no additional costs shall be billed to the customer. When a second meter is requested by the customer that is not required by the Company, the customer shall be responsible for the cost of the meter, the installation, and any additional costs.

GENERAL INFORMATION

13. Distributed Energy Resources: (Cont'd)

D. Programs

1. Grandfathered NEM

Grandfathered Net Energy Metering for Solar Electric Generating Equipment, Farm Waste Electric Generating Equipment, Micro-Combined Heat and Power Generating Equipment, Fuel Cell Electric Generating Equipment, and Micro-Hydroelectric Generating Equipment (PSL §66-j) and Wind Generation Equipment (PSL §66-l). Such system must be connected to the customer's electric system and must be operated in accordance with applicable government and industry standards, that is connected to the electric system and operated in conjunction with the Company's transmission and distribution facilities, and that is operated in compliance with any standards and requirements established under this section. A customer may include energy storage equipment when submitting an application for net metering pursuant to this subdivision of Grandfathered NEM.

A. Eligible Generation Facilities pursuant to PSL §66-j:

1. Capacity and Type
The total rated generating capacity for solar, farm waste, micro-hydroelectric, MCHP and fuel cell electric generating equipment owned, leased or operated by customer-generators in the Company's service area shall not exceed 98.16 MW, the total rated generating capacity of interconnected projects served by the Company under PSL §66-j as of the close of business on March 9, 2017, including projects to be served by the Company under PSL §66-j for which either Step 8 (for projects greater than 50kW) or Step 4 (for projects 50kW or less) of the Standard Interconnection Requirements (SIR), as applicable, had been completed by the close of business on March 9, 2017. This MW limit shall automatically decrease as projects served under PSL §66-j are taken out of service, but shall not decrease below 28.26 MW, representing 1% of the Company's electric demand for the year 2005.

a) A Residential Customer (as defined by HEFPA), and farm customer as defined in Subdivision 11 of Section 301 of the Agriculture and Markets Law, may install and operate solar generating equipment located and used at his or her residence. Solar generating equipment is defined as a solar system, with a rated capacity of not more than 25 kW that is manufactured, installed and operated in accordance with applicable government and industry standards. Farm customers may install solar generating equipment with a rated capacity of not more than 100 kW, that is manufactured, installed and operated in accordance with applicable government and industry standards.

b) A Non-Residential Customer who operates solar generating equipment located and used at its premises. Solar generating equipment is defined as a solar system that is manufactured, installed and operated in accordance with applicable government and industry standards with a rated capacity of not more than 2,000 kW.

c) A customer, residential or non-residential, who owns or operates farm waste electric generating equipment that generates electric energy from biogas produced by the anaerobic digestion of agricultural wastes with a rated capacity of not more than 2,000 kW, located and used at their "farm operation" as defined in Subdivision 11 of Section 301 of the Agriculture and Markets Law. Such definition states that a "farm operation" means the land and on-farm buildings, equipment, manure processing and handling facilities, and practices which contribute to the production, preparation and marketing of crops, livestock and livestock products as a commercial enterprise, including a "commercial horse boarding operation" as defined in subdivision thirteen of this Section 301 of the Agriculture and Markets Law.

GENERAL INFORMATION

13. Distributed Energy Resources: (Cont'd)
D. Programs: (Cont'd)
1. Grandfathered NEM (Cont'd)
A. Eligible Generation Facilities pursuant to PSL §66-j: (Cont'd)

i. The farm waste electric generating equipment must be manufactured, installed and operated in accordance with applicable government and industry standards. The equipment must be fueled, at a minimum of 90% on an annual basis, by biogas produced from the anaerobic digestion of agricultural waste such as livestock manure materials, crop residues and food processing waste. The equipment must be fueled by biogas generated by anaerobic digestion with at least 50% by weight of its feedstock being livestock manure materials on an annual basis. The customer, at its expense, shall promptly provide to the Company all relevant, accurate and complete information, documents, and data, as may be reasonably requested by the Company, to enable the Company to determine whether the customer is in compliance with these requirements.

d) A Residential Customer (as defined by HEFPA) who owns, leases or operates MCHP generating equipment. MCHP generating equipment is defined as an integrated, cogenerating building heating and electrical power generation system, operating on any fuel and of any applicable engine, fuel cell, or other technology, with a rated capacity of at least one kW and not more than 10 kW electric and any thermal output that at full load has a design total fuel use efficiency in the production of heat and electricity of not less than 80%, and annually produces at least 2,000 kWh of useful energy in the form of electricity that may work in combination with supplemental or parallel conventional heating systems, that is manufactured, installed and operated in accordance with applicable government and industry standard.

e) A Residential Customer (as defined by HEFPA) who owns, leases or operates fuel cell generating equipment located and used at his or her residence. Fuel cell generating equipment is defined as a solid oxide, molten carbonate, proton exchange membrane or phosphoric acid fuel cell with a combined rated capacity of not more than 10 kW; that is manufactured, installed and operated in accordance with applicable government and industry standards.

f) A Non-Residential Customer who owns, leases or operates fuel cell generating equipment located and used at their premises. Fuel cell generating equipment is defined as a solid oxide, molten carbonate, proton exchange membrane or phosphoric acid fuel cell with a combined rated capacity of not more than 2,000 kW that is manufactured, installed and operated in accordance with applicable government and industry standards.

g) A Residential Customer (as defined by HEFPA) who owns or operates micro-hydroelectric generating equipment located and used at their residence. Micro-hydroelectric generating equipment is defined as a hydroelectric system with a rated capacity of not more than 25 kW; that is manufactured, installed and operated in accordance with applicable government and industry standards.

h) A Non-Residential Customer who owns or operates micro-hydroelectric generating equipment located and used at their premises. Micro-hydroelectric generating equipment is defined as a hydroelectric system with a rated capacity of not more than 2,000 kW; that is manufactured, installed and operated in accordance with applicable government and industry standards.

GENERAL INFORMATION

13. Distributed Energy Resources: (Cont'd)
D. Programs: (Cont'd)
1. Grandfathered NEM (Cont'd)

A. Eligible Generation Facilities pursuant to PSL §66-j:

2. Term
   1. The Company shall net the electricity (kWh) delivered to the customer life of the generating system for a customer that on or prior to March 9, 2017 has:
      a. completed Step 4 of the SIR Addendum for generating equipment less than 50 kW; or
      b. installed generating equipment on or prior to March 9, 2017.
      c. A customer may opt to take service under Rule 26, Value of Distributed Energy Resources (VDER). Such election shall be a one-time election and shall be irrevocable.

   2. A customer that installs solar generating equipment after March 9, 2017 shall refer to Rule 26, Value of Distributed Energy Resources (VDER), A. Phase One Net Energy Metering ("NEM") or B. Value Stack, as applicable

3. Billing

   1. Residential

      For each billing period during the term of the SIR Contract, the Company shall net the electricity (kWh) delivered to the customers with the electricity (kWh) supplied by the customer to the Company.

      a) If the electricity (kWh) supplied by the Company exceeds the electricity supplied by the customer to the Company during the billing period the customer shall be billed for the net kWh supplied by the Company to the customer at the standard service class rates. For customers billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak or Day/Night, netting shall occur in each time period.
      b) If the electricity (kWh) supplied by the customer to the Company during the billing period exceeds the electricity (kWh) supplied by the Company to the customer, a kWh credit shall be carried forward for the next billing period. For customers billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak or Day/Night, the kWh credit shall be carried forward as a credit to the appropriate time period.
      c) For customers billed on TOU rates, if the electricity (kWh) supplied by the customer to the Company is not metered for each TOU period and until such time as metering is installed to measure electricity supplied to the Company in each TOU period, an allocation of the electricity supplied to the Company shall be done according to allocation factors as set forth in a Special Provision provided in each service classification in this Schedule.
      d) For Residential Solar and Farm Waste Generators – Cash-Out Provision
         1. If (a) on an annual basis, during the term of the SIR Contract or (b) on the date the SIR Contract is terminated pursuant to the terms and conditions of said Contract, there exists a positive (kWh) balance for an accumulation of excess generation provided to the Company, then a cash payment shall be issued to the customer.
            i. For a Non-hourly Pricing customer, the payment shall be for an amount equal to the product of the excess balance times the average avoided cost for energy over the most recent 12-month period.
            ii. For an Hourly Pricing customer, the payment shall be for the remaining portion of the excess credit priced at avoided cost, after credits are applied to the current bill period. Any remaining non-avoided cost monetary credits are reset to zero.

GENERAL INFORMATION

13. Distributed Energy Resources: (Cont'd)
    D. Programs: (Cont'd)
    1. Grandfathered NEM (Cont'd)

A. Eligible Generation Facilities pursuant to PSL §66-j:

3. Billing (Cont'd)
    1. Residential (Cont'd)

        a. A customer shall be provided a one-time option to select an individual anniversary date for the annual cash-out of excess net metering credits.
        i. For a Non-hourly Pricing customer, the initial cash-out payment shall be equal to the product of excess balance multiplied by the average avoided cost for the energy over the number of months the customer has taken service under this provision.
        ii. For an Hourly Pricing customer, the initial cash-out payment shall be for the remaining portion of the excess credit priced at avoided cost, after credits are applied to the current bill period. Any remaining non-avoided cost monetary credits are reset to zero. Upon the Company's determination that the customer has taken service under this Section while in violation of the conditions of service set forth herein, the customer shall forfeit any positive balance accrued during the annual period in which the violation occurred.

    2. Non-Residential
    For each billing period during the term of the SIR Contract, the Company shall net the electricity (kWh) delivered to the customers with the electricity (kWh) supplied by the customer to the Company.

    Non-Hourly Pricing
    a) If the electricity (kWh) supplied by the Company exceeds the electricity supplied by the customer to the Company during the billing period, the customer shall be billed for the net kWh supplied by the Company to the customer at the standard service class rates. For customers billed on Time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak, netting shall occur in each time period.
    b) If the electricity (kWh) supplied by the customer to the Company during the billing period exceeds the electricity (kWh) supplied by the Company to the customer, a kWh credit shall be carried forward for the next billing period. For customer billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak, the kWh credit shall be carried forward as a credit to the appropriate time period.
    c) For a demand-billed customer, prior to carrying forward any kWh credit, the kWhs shall be converted to a dollar value using the applicable tariff per kWh rate and applied as a credit to the current utility bill. If the dollar value of the kWh exceeds the current utility bill, any remaining dollars shall be converted back to kWhs and carried forward for the next billing period as a kWh credit.
    d) For customers billed on TOU rates, if the electricity (kWh) supplied by the customer to the Company is not metered for each TOU period and until such time as metering is installed to measure electricity supplied to the Company in each TOU period, an allocation of the electricity supplied to the Company shall be done according to allocation factors as set forth in a Special Provision provided in each service classification in this Schedule.

    Hourly Pricing
    a) For customers billed on Hourly Pricing, for each hour, the customer's usage and its generation are netted within the hour.
    b) Kilowatt-hour charges are calculated using the consumption in each hour in which the customer's usage exceeds the customer's generation multiplied by the applicable charge.

GENERAL INFORMATION

13. Distributed Energy Resources: (Cont'd)
    D. Programs: (Cont'd)

1. Grandfathered NEM (cont'd)
A. Eligible Generation Facilities pursuant to PSL §66-j:

3. Billing (Cont'd)
2. Non-Residential (Cont'd)
Hourly Pricing (Cont'd)

c) For each hour the electricity generated and supplied by the customer exceeds the customer's usage, the kWh difference is multiplied by the applicable tariff per kWh rates (e.g., Energy Charge, Supply Charge, Merchant Function Charge, Ancillary & NTAC, transmission project costs allocated to the Company under the NYISO tariff as approved by FERC, SBC, RDM, and Supply Adjustment Charge.) This is the current month's excess monetary credit.

d) The excess monetary credit from the current and/or prior bill period(s) is applied to the current billing period. If the excess monetary credit exceeds the current utility bill, the monetary credit is carried forward to the next billing period.

B. Eligible Wind Generation Facilities PSL §66-l

1. Eligible Capacity

Application of the Wind Residential Service Option shall be available to eligible customers, on a first come, first served basis, until the total rated generating capacity for all wind electric generating equipment owned or operated by customer generators in the Company's service area is equivalent to 8,478 kW (3 /10% of the Company's electric demand for the year 2005) and is available only in non-network areas of the Company's territory.

a. Applicable to any Residential Customer (as defined by HEFPA) who operates wind generating equipment located and used at his or her primary, legal residence. Wind generating equipment is defined as a wind system, with a rated capacity of not more than 25 kW that is manufactured, installed and operated in accordance with applicable government and industry standards.

b. Applicable to any customer who owns or operates farm wind electric generating equipment ("Facility"), that generates electric energy with a rated capacity of not more than 500 kW; where the customer's primary residence is located on the same land used for his or her "farm operation" as defined in Subdivision 11 of Section 301 of the Agriculture and Markets Law. Such definition states that a "farm operation" means the land and on-farm buildings, equipment, manure processing and handling facilities, and practices which contribute to the production, preparation and marketing of crops, livestock and livestock products as a commercial enterprise, including a "commercial horse boarding operation" as defined in subdivision thirteen of this Section 301 of the Agriculture and Markets Law.

c. Applicable to any Non-Residential Customer who operates wind generating equipment located and used at its premises. Wind generating equipment is defined as a wind system that is manufactured, installed and operated in accordance with applicable government and industry standards with a rated capacity of not more than 2,000 kW.

GENERAL INFORMATION

13. Distributed Energy Resources (Cont'd)

D. Programs: (Cont'd)

1. Grandfathered NEM (Cont'd)

B. Eligible Wind Generation Facilities PSL §66-l (Cont.'d)

2. Billing

For each billing period during the term of the SIR Contract, the Company shall net the electricity (kWh) delivered to the customers with the electricity (kWh) supplied by the customer to the Company.

A) If the electricity (kWh) supplied by the Company exceeds the electricity supplied by the customer to the Company during the billing period the customer shall be billed for the net kWh supplied by the Company to the customer at the standard service class rates. For customers billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak or Day/Night, netting shall occur in each time period.

B) If the electricity (kWh) supplied by the customer to the Company during the billing period exceeds the electricity (kWh) supplied by the Company to the customer, a kWh credit shall be carried forward for the next billing period. For customers billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak or Day/Night, the kWh credit shall be carried forward as a credit to the appropriate time period.

3. Cash-out

Applicable to Residential Wind or Farm Wind customers:

a. If, (a) on an annual basis, during the term of the SIR Contract or (b) on the date the SIR Contract is terminated pursuant to the terms and conditions of said Contract, there exists a positive (kWh) balance for an accumulation of excess generation provided to the Company, then a cash payment shall be issued to the customer.
   i. For a Non-hourly Pricing customer, the payment shall be for an amount equal to the product of the excess balance times the average avoided cost for energy over the most recent 12-month period.
   ii. For an Hourly Pricing customer, the payment shall be for the remaining portion of the excess credit priced at avoided cost, after credits are applied to the current bill period. Any remaining non-avoided cost monetary credits are reset to zero.

b. A customer shall be provided a one-time option to select an individual anniversary date for the annual cash-out of excess net metering credits.

C. Upon the Company's determination that the customer has taken service under Grandfathered NEM while in violation of the conditions of service set forth herein, the customer shall forfeit any positive balance accrued during the annual period in which the violation occurred.

2. Community Distributed Generation

Please refer to Rule 23, Community Distributed Generation for requirements specific to a Host and Satellite that is participating in Community Distributed Generation and for rules pertaining to the calculation and application of credits for excess generation.

3. Remote Net Metering

Please refer to Rule 28, Remote Net Metering for requirements specific to a customer that is participating in Remote Net Metering and for rules pertaining to the calculation and application of credits for excess generation.

4. Remote Crediting

Please refer to Rule 35, Remote Crediting Program for rules specific to a Host and Satellite that is participating in Remote Crediting program and for rules pertaining to the calculation and application of credits for excess generation.

GENERAL INFORMATION

13. Reserved for Future Use

GENERAL INFORMATION

13. Reserved for Future Use

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GENERAL INFORMATION

19. Electric Vehicle Phase-In Rate

A. Eligibility

A customer served under Service Classification Nos. 3, 7 or 8 that installs and operates electric vehicle charging equipment may apply and qualify for the Electric Vehicle Phase-In Rate ("EV Phase-In Rate") subject to the following conditions:

- i. A customer operating electric vehicle charging equipment must have a Charging Ratio of 50 percent or greater in order to be eligible to take service under the EV Phase-In Rate.
  - a. Charging Ratio is defined as the ratio of the sum of the EV charging nameplate capacity in kW to the sum of the customer's maximum simultaneous demand of all onsite load in kW, including electric vehicle charging load.
    - i. The maximum simultaneous demand of all load (in kW) onsite will be determined from the most recent Electrical Load Form on the account. The Electrical Load Form provides the customer's anticipated on-site load from all electrical equipment sources and is general submitted by a customer when requesting new or upgraded electric service.
    - ii. The Company may request an updated Electrical Load Form at any point in time that is subsequent to the customer's interconnection of the electric vehicle charging equipment for the purposes of determining eligibility.
    - iii. The Charging Ratio shall be determined at the time of application and shall remain the Charging Ratio until such time that the customer provides a new Electrical Load Form if adding or removing load.
    - iv. The Company reserves the right to re-evaluate the Charging Ratio and eligibility subsequent to application for, or a change in electric service.
    - v. For a customer that chooses to separately meter their EV charging load, the Charging Ratio shall be equal to 100 percent.
- ii. A customer operating electric vehicle charging with an Annual Load Factor greater than 25 percent is not eligible to enroll in the EV Phase-In Rate.
- iii. A customer currently enrolled in the Excelsior Jobs Program pursuant to Rule 4.L.3 of this Schedule is ineligible for the EV Phase-In Rate.
- iv. A customer that receives an allocation of power from NYPA pursuant to the ReCharge NY program is eligible to elect the EV Phase-In Rate.
- v. A customer currently participating in the Company's Per-Plug Incentive ("PPI") Program is ineligible for the EV Phase-In Rate.
  - a. A customer participating in the Company's PPI Program shall have a one-time option to either continue participating in the PPI Program for the remainder of the Customer's eligibility period or take service under the EV Phase-In Rate.
- vi. An AMI meter capable of interval billing must be installed prior to enrollment in the EV Phase-In Rate.

GENERAL INFORMATION

19. Electric Vehicle Phase-In Rate (Cont'd)

B. Billing and Enrollment

1. An eligible customer shall notify the Company of their intent to enroll in the EV Phase-In Rate.
   a) Enrollment shall take effect during the customer's following billing cycle.
   b) A customer participating the EV Demand Charge Rebate Program (Rule 38) will not be automatically enrolled in the EV Phase-In Rate once the EV Demand Charge Rebate is no longer available to customers (Rule 38.D).
2. A customer currently served under the EV Phase-In Rate that elects to opt-out shall not be eligible to re-enroll in the EV Phase-In Rate unless a customer can demonstrate to the Company that there has been additional electric vehicle charging infrastructure installed.
3. A customer served under the EV Phase-In Rate shall be subject to all other rates, charges, terms, and conditions of their otherwise applicable service class.
   a. In lieu of the demand charges specified in the customers otherwise applicable service class, a customer shall be subject to the charges specified below in Rule 19.C.

C. Demand (kW) and Energy (kWh) Delivery Charges

Customers shall be subject to the rates below based on their otherwise applicable service class.

Tier 1: Customers with an Annual Load Factor ≤ 10 percent

	On-Peak Energy Charge (per kWh)	**Off-Peak Energy Charge (per kWh)**	**Super-Peak Energy Charge (per kWh)**
Service Classification No. 3	$0.08479	$0.04240	$0.12719
Service Classification No. 7	$0.09305	$0.04653	$0.13958
Service Classification No. 8-S	$0.06333	$0.03166	$0.09499
Service Classification No. 8-P	$0.05770	$0.02885	$0.08656
Service Classification No. 8-SubInd	$0.03692	$0.01846	$0.05538
Service Classification No. 8-SubCom	$0.03999	$0.01999	$0.05998
Service Classification No.8-Substation	$0.20769	$0.10384	$0.31153
Service Classification No. 8-T	$0.04532	$0.02266	$0.06798

Tier 2: Customers with an Annual Load Factor > 10 percent and ≤ 15 percent

	On-Peak Energy Charge (per kWh)	**Off-Peak Energy Charge (per kWh)**	**Super-Peak Energy Charge (per kWh)**	**Demand Charge (All kW, per kW)**
Service Classification No. 3	$0.06360	$0.03180	$0.09539	$6.57
Service Classification No. 7	$0.06979	$0.03489	$0.10468	$6.42
Service Classification No. 8-S	$0.04750	$0.02375	$0.07124	$5.36
Service Classification No. 8-P	$0.04328	$0.02164	$0.06492	$5.31
Service Classification No. 8-SubInd	$0.02769	$0.01385	$0.04154	$3.64
Service Classification No. 8-SubCom	$0.02999	$0.01500	$0.04499	$3.80
Service Classification No. 8-Substation	$0.15577	$0.07788	$0.23365	$3.14
Service Classification No. 8-T	$0.03399	$0.01700	$0.05099	$3.62

GENERAL INFORMATION

19. Electric Vehicle Phase-In Rate (Cont'd)

C. Demand (kW) and Energy (kWh) Delivery Charges (Cont'd)

Tier 3: Customers with an Annual Load Factor > 15 percent and ≤ 20 percent

	On-Peak Energy Charge (per kWh)	Off-Peak Energy Charge (per kWh)	Super-Peak Energy Charge (per kWh)	Demand Charge (All kW, per kW)
Service Classification No. 3	$0.04240	$0.02120	$0.06360	$13.14
Service Classification No. 7	$0.04653	$0.02326	$0.06979	$12.84
Service Classification No. 8-S	$0.03166	$0.01583	$0.04750	$10.72
Service Classification No. 8-P	$0.02885	$0.01443	$0.04328	$10.63
Service Classification No. 8-SubInd	$0.01846	$0.00923	$0.02769	$7.27
Service Classification No. 8-SubCom	$0.01999	$0.01000	$0.02999	$7.60
Service Classification No. 8-Substation	$0.10384	$0.05192	$0.15577	$6.29
Service Classification No. 8-T	$0.02266	$0.01133	$0.03399	$7.24

Tier 4: Customers with an Annual Load Factor > 20 percent and < 25 percent

	On-Peak Energy Charge (per kWh)	Off-Peak Energy Charge (per kWh)	Super-Peak Energy Charge (per kWh)	Demand Charge (All kW, per kW)
Service Classification No. 3	$0.02120	$0.01060	$0.03180	$19.70
Service Classification No. 7	$0.02326	$0.01163	$0.03489	$19.25
Service Classification No. 8-S	$0.01583	$0.00792	$0.02375	$16.08
Service Classification No. 8-P	$0.01443	$0.00721	$0.02164	$15.94
Service Classification No. 8-SubInd	$0.00923	$0.00462	$0.01385	$10.91
Service Classification No. 8-SubCom	$0.01000	$0.00500	$0.01500	$11.40
Service Classification No. 8-Substation	$0.05192	$0.02596	$0.07788	$9.43
Service Classification No. 8-T	$0.01133	$0.00567	$0.01700	$10.85

Customers with an Annual Load Factor > 25 percent

A customer with an Annual Load Factor of 25 percent or greater shall pay the delivery charges as specified in the otherwise applicable service class until such time that the Annual Load Factor is less than 25 percent.

To the extent that the load factor of a participant in the EV Phase-In Rate exceeds 25 percent for four consecutive measurement periods (a two-year period), that customer shall no longer be eligible for participation in the EV Phase-In Rate. A customer may have the ability to opt back into the program if they can demonstrate to the Company that there has been additional electric vehicle charging infrastructure installed.

GENERAL INFORMATION

19. Electric Vehicle Phase-In Rate (Cont'd)

D. Rate Periods

Summer (June through September):

a. **Off-Peak**: Hour beginning 11:00 PM through Hour Beginning 6:00 AM
b. **On-Peak**: Hour beginning 7:00 AM through Hour Beginning 1:00 PM
c. **Super-Peak**: Hour beginning 2:00 PM through Hour Beginning 5:00 PM
d. **On-Peak**: Hour beginning 6:00 PM through Hour Beginning 10:00 PM

Off Season (October through May):

a. **Off-Peak**: Hour beginning 11:00 PM through Hour Beginning 6:00 AM
b. **On-Peak**: Hour beginning 7:00 AM through Hour Beginning 10:00 PM

All hours on weekends and the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day; shall all be considered as **Off-Peak.**

E. Increase in Rates and Charges

The rates under the EV Phase-In Rate shall be increased by a surcharge pursuant to Section 4.J of this Schedule to reflect the tax rates applicable within the municipality where the customer takes service.

GENERAL INFORMATION

19. Electric Vehicle Phase-In Rate (Cont'd)

F. Semi-Annual Load Factor Review

The Company shall calculate an annual load factor that will determine the applicable rate phase that will apply to the customer twice per year. The Winter Annual Load Factor calculation will be set based on a customer's load data from the prior period of January 1 – December 31 and such load factor will be used to determine the effective rate phase that is applicable to the customer's bill for such bill having a "from" date on or after March 1. The Summer Annual Load Factor calculation will be set based on a customer's load data from the period July 1 – June 30 and such load factor will be used to determine the effective rate phase that is applicable to the Customer's bill for such bill having a "from" date on or after September 1. The Winter Annual Load Factor and Summer Annual Load Factor will be calculated as follows:

For customers with EV Charging Load and Other On-Site Load

Determining the load factor for the 12-month period by taking the ratio of the kWh usage during the 12-month period to the maximum demand during that 12-month period times the number of hours in the 12-month period.

For customers with EV Charging Load Only

Determining the load factor for the 12-month period by taking the ratio of the kWh usage during the 12-month period to the sum of the installed EV kW charging capacity times the number of hours in the 12-month period.

For a customer enrolling in the EV Phase-In Rate that does not have existing load data, the customer shall be placed in Tier 1 until such time that at least six months of load data is available for use in calculating the Winter Annual Load Factor or the Summer Annual Load Factor for determination of the appropriate phased rate. For such customer, the definitions for the calculation of the load factor in above shall be amended to calculate the load factor for a 6-month period until such time that the Winter Annual Load Factor or Summer Annual Load Factor can be calculated with 12-months of load data.

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

Reserved for Future Use

GENERAL INFORMATION

20. Reserved for Future Use

GENERAL INFORMATION

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GENERAL INFORMATION

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GENERAL INFORMATION

20. Reserved for Future Use

GENERAL INFORMATION

20. Reserved for Future Use

GENERAL INFORMATION

20. Reserved for Future Use

GENERAL INFORMATION

21. COMPLIANCE WITH DIRECTIVES OF THE NEW YORK INDEPENDENT SYSTEM OPERATOR ("NYISO")

Compliance with directives of the New York Independent System Operator (NYISO) shall, without limitation by reason of specification, constitute a circumstance beyond the control of the Company for which the Company shall not be liable; provided, however, that the Company shall not be absolved from any liability to which it may otherwise be subject for negligence in the manner in which it carries out the NYISO's instructions. (See Rule 6.A.)

Without limiting the generality of the foregoing, the Company may, without liability therefore, interrupt, reduce or impair service to any Customer or Customers in the event of an emergency threatening the integrity of its system, or any other systems with which it is directly or indirectly interconnected, if in its sole judgment or that of the NYISO (Rule 6.A), such action shall prevent, alleviate or reduce the emergency condition, for such period of time as the Company, or said NYISO, deems necessary.

22. COMPLIANCE WITH DISCONTINUANCE DIRECTIVES FROM THE NEW YORK STATE DEPARTMENT OF TRANSPORTATION (DOT):

The Company is required to discontinue electric service to illuminated outdoor advertising signs, displays, or devices which have been declared illegal by the DOT under Section 88(8) of the Highway Law.

The DOT shall reimburse the Company for the full cost, as defined hereunder in Rule 4.E. – Charges for Special Services, of terminating service to the subject sign, display or device.

Prior to discontinuance the Company must receive from the DOT a written notification and request for discontinuance of service, signed by an authorized DOT official, stating that the sign display or device has been declared a public nuisance, its owner has received 30 days' written notice to remove or conform it with the provisions of Section 88 and that the determination of DOT has not been stayed, modified or revoked. The DOT must also include in its written notification to the Company the anticipated removal date of the subject sign, display or device, and allow the Company up to 15 days following its receipt of written notice to effect the discontinuance of service.

The Company shall discontinue service under this provision only if there shall be no adverse effect on electric service supplied for any other purpose.

GENERAL INFORMATION

23. Community Distributed Generation

A customer may participate in Community Distributed Generation ("CDG") as provided herein.

The CDG Host and CDG Satellites must meet all terms and conditions of this Rate Schedule and the requirements of the PSC that are adopted pursuant to its Orders issued in Case 15-E-0082 and Case 15-M-0180, as they may be amended or superseded from time to time.

1. Definitions

   Available Credit: The Total Available Credit shall be determined as the sum of i) the CDG project's Value Stack Compensation for the applicable billing period multiplied by the CDG Satellite's Allocation Percentage; and ii) any retained credits that have been banked or re-allocated to the CDG Satellite's account.

   CDG Host: A non-residential customer that owns or operates electric generating equipment eligible for net metering under this Rule and whose net energy produced by its generating equipment is applied to the accounts of other electric customers ("CDG Satellites") with which it has a contractual arrangement related to the disposition of net metering credits.

   CDG Host Anniversary Month: 11 months from the CDG Host's initial CDG bill period start date. The CDG Host Anniversary month cannot be modified or changed.

   CDG Satellites: A customer who is participating in a CDG Program. Each customer shall own or contract for a proportion of the credits accumulated at the meter of the CDG Host.

   Excess Generation: The electricity (kWh) supplied by the CDG Host to the Company during the billing period that exceeds the electricity (kWh) supplied by the Company to CDG Host. For customers billed on time-differentiated rates (TOU meter), *e.g.,* On-Peak/Off-Peak, the excess is calculated and maintained for each peak. For hourly billed customers, excess generation is calculated for each hourly period.

   Net Member Credits: Credits shall be determined as the CDG Savings Rate multiplied by the Applied Credit, which is defined as the minimum of: the Total Available Credit and (2) the CDG Satellite's current electric bill for the applicable billing period.

   Net-Metered Generation Facility: A generation facility eligible for net metering as a non-residential customer in conformance with PSL 66-j or 66-l, limited in size to 5 MW (Micro-Combined Heat and Power, ("CHP") is excluded from this Rule), located behind a host meter attached to a load under either a demand or non-demand classification. A CDG Host with an eligible Clean Energy Standard Tier 1 technology as provided in Appendix A of the Commission's Order Adopting a Clean Energy Standard, issued on August 1, 2016 in Case 15-E-0302, and participating in Rule 26.B. Value Stack may qualify as a generation facility for CDG and be compensated based on Rule 26.B. Stand-alone energy storage systems will be eligible under Rule 23 subject to the requirements described in Rule 26.B.

   Operating Agreement: Details the process and contractual agreement between the Company and CDG Host.

   Unallocated Credits: If sum of CDG Satellite's is less than 100%, difference becomes Unallocated satellite percentage. The Unallocated Satellite Percentage will be multiplied by the CDG project's Value Stack Compensation for the applicable billing period, excluding any Market Transition Credits or Community Credits to determine the Unallocated Credits. The Unallocated Credits will be added to the current retained/banked credits on the CDG Host account for future redistribution to the CDG Satellites.

GENERAL INFORMATION

23. Community Distributed Generation

2. Initial and Subsequent Applications by CDG Hosts
   The CDG Host must be a non-residential customer with a Net-Metered Generation Facility. The CDG Host must certify in writing to the Company, both prior to commencing net metered service under CDG and annually thereafter, that it has met all program criteria set forth in the Commission's Orders, including but not limited to certifying that they can satisfy all obligations assumed with respect to project members and other requirements established by the Commission.
   a. A CDG Host shall comply with the requirements set forth in the UBP-DER Addendum.
   b. Initial Allocation Requests: At least 60 days before commencing net metered service under CDG, the CDG Host shall designate in its initial application for CDG service the CDG Host Account and CDG Satellite Accounts that shall receive net metered service under CDG.
      i. Accepted Allocation Requests shall be effective with the first full Host Account billing period from the later of 60 days after receipt of such request or effective date of interconnection.
   c. Subsequent Allocation Requests: After commencing net metered service under CDG, the CDG Host may modify its CDG Satellite Accounts and/or the percentage allocated to itself or one or more of its CDG Satellite Accounts once per CDG Host billing cycle by giving notice to the Company no less than 30 days before the CDG Host Account's cycle billing date to which the modifications apply.
      i. Accepted Allocation Requests shall be effective with the next full Host Account billing period 30 days after receipt of such request.

GENERAL INFORMATION

23. Community Distributed Generation

3. CDG Host Submission Requirements Applicable to 2a and 2b Above:
   a. A CDG Host that provides a CDG Satellite's name and account number to the Company (and such other information as the Company may require to verify the customer's account based on the information provided), as described in the Company's CDG Operating Agreement, is certifying that it has written authorization from the customer to request and receive that customer's historical usage information and, upon enrolling a CDG Satellite Account, that it has entered into a written contract with such customer. The Company shall not be responsible for any contractual arrangements or other agreements between the CDG Host and CDG Satellite, including contractual terms, pricing, dispute resolution, and contract termination.
   b. The CDG Host must designate no fewer than 10 CDG Satellite Accounts that meet the specifications set forth in Section 3, except when the project:
      i. is located on the site of a property serving multiple residential or non-residential customers.
      ii. only serves farm operations ("CDG Farm Project"), as defined in PSL Agricultural and Markets Law, Section 301(11); and residences of individuals who own or are employed by the served farm operations. A CDG Farm Project that seeks to waive the minimum number of Satellite Accounts shall be responsible for certifying to the Company that each Satellite Account is either a farm operation or the owner or employee of one of the farm operation Satellite Accounts.
   c. Satellite allocations of Host Account Excess Generation should be specified in a percentage up to three decimal places of accuracy.
   d. The total allocations must equal 100 % including any portion to be designated to the CDG Host.
   e. Submittals in which allocations do not equal 100.000% shall be rejected, and the CDG Host must submit a new allocation percentage 60 days before net metered service shall commence. Additionally, the CDG Host must allocate the project's generation to its CDG Satellites, according to the following:

      i. A CDG Host which has paid 25% of interconnection costs, or executed a SIR contract if no such payment is required, on or before February 12, 2021, and has either interconnected to the Company's distribution system on or after February 13, 2021, in accordance with the SIR or interconnected to the Company's distribution system before February 13, 2021, but did not begin taking service as a CDG Host by receiving credits for injections before February 13, 2021, must allocate at least 60% of the project generation to CDG Satellites that are:

         a) Served under SC1, SC2, SC4; or

         b) Served under SC3, SC7, SC8, SC9, and where the CDG Satellite has an average billed kW less than or equal to 25 kW based on the most recent 12 monthly billing periods; or

         c) a multi-unit building with a single meter serving multiple occupants, as described in Rule 23.3.f.i; or

         d) served under PSC No. 18 if the project receives compensation based on Rule 26.B. Value Stack.

         e) if an allocation file was accepted by the Company before February 12, 2021, that included more than 40% of the allocations to subscribers served under SC3, SC7, SC8, SC9 where the CDG Satellite has an average billed kW greater than 25 kW based on the most recent 12 monthly billing periods of CDG Satellites with an average billed kW greater than 25 kW, the Company will accept allocation files that have no more than 40% allocated to customers served under demand billed service classes that have allocations of more than 25 kW as measured by the allocation percentage multiplied by the AC nameplate rating of the CDG Host facility for the remainder of the CDG Host's project term.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

3. CDG Host Submission Requirements Applicable to 2a and 2b Above: (Cont'd)

ii. A CDG Host which is interconnected to the Company's distribution system in accordance with the SIR, on or before February 12, 2021 and has begun taking service as a CDG Host by receiving credits for injections before February 12, 2021, must allocate at least 60% of the project generation to CDG Satellites that are:

a) Served under SC1, SC2, SC4; or
b) Served under SC3, SC7, SC8, SC9, and where the CDG Satellite has an average billed kW less than
or equal to 25 kW based on the most recent 12 monthly billing periods; or,
c) A multi-unit building with a single meter serving multiple occupants, as described in Rule 23.3.f.i; or
d) served under PSC No. 18 if the project receives compensation based on Rule 26.B. Value Stack.

iii. A CDG Host which satisfies the 25% interconnection cost responsibility set forth in the Addendum-SIR, or executed a SIR contract if no such obligation is required, after February 12, 2021 must allocate at least 60% of the project generation to CDG Satellites that are:

a) Served under SC1, SC2, SC4; or
b) Served under SC3, SC7, SC8, SC9, and where the CDG Satellite has an average billed kW less than or equal to 25 kW based on the most recent 12 monthly billing periods; or
c) A multi-unit building with a single meter serving multiple occupants, as described in e Rule 23.3.f.i; or
d) served under PSC No. 18 if the project receives compensation based on Rule 26.B. Value Stack

iv. Once a CDG Host's project has been interconnected to the Company's distribution system in accordance with the SIR, and begun taking service pursuant to this Rule by receiving credits for injections, the project must continue to use the allocation methodology approved by the Company for that project.

v. Verification of satellites is completed by the Company each time an allocation form is submitted by a CDG Host based on the methodology established during Company's final approval of CDG Host's initial allocation form.

b. No more than 40% of the Excess Generation of the CDG Host may serve CDG Satellites of 25 kW or greater (for those members collectively); provided, however, that the CDG Host may:
ii. include each dwelling unit located within a multi-unit building and served indirectly as though it were a separate participant for determining whether the 10 CDG Satellite Account minimum and 40% output limits are reached; or
iii. for a CDG Farm Project, waive the requirement that no single large Satellite Account member or group of Satellite Account members consume more than 40% of the credits generated by the CDG Farm Project.

c. A CDG Host Account shall not be a Remote Net Metered Host or Satellite Account. If the CDG Host Account was previously established under Remote Net Metering as an energy-only account and its Satellite Accounts receive monetary crediting, the CDG Host must permanently surrender its rights to monetary crediting under a non-demand service classification before participating in CDG.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

3. CDG Host Submission Requirements Applicable to 2a and 2b Above: (Cont'd)
    d. The CDG Host shall submit a completed application via an electronic transfer to the Company, and shall certify to the Company that its project meets the PSC's eligibility requirements as specified in its Orders in Case 15-E-0082 and as may be revised thereafter.
    e. A CDG Host shall recertify on an annual basis they continue to meet all requirements as set forth in this Rule and in the CDG Operating Agreement.
4. CDG Satellite Account Requirements
    a. A CDG Satellite Account shall have only one CDG Host Account.
    b. All associated CDG Satellite Accounts must be located within the Company's service territory and within the same NYISO zone as the CDG Host Account, except for a CDG Facility that is being compensated pursuant to Rule 26.B. Value Stack. CDG Satellite Accounts of a CDG Host Account that is compensated pursuant to Rule 26.B. Value Stack, do not need to be located within the same NYISO zone as the CDG Host Account of the Company's service territory.
    c. The CDG Satellite Account shall not be a net metered customer-generator or a Remote Net Metered Host or Satellite Account or take Standby Service under SC14.
    d. Each CDG Satellite Account must take a percentage of the output of the CDG Host's Excess Generation. The percentage must amount to at least 1,000 kWh annually but may not exceed the CDG Satellite Account's historic average annual kWh usage (or forecast usage if historic data is not available).
    e. A non-metered account may qualify as a Satellite Account if the CDG Host is being compensated based on a monetary crediting methodology pursuant to Rule 26, Value of Distributed Energy Resources ("VDER").

GENERAL INFORMATION

23. Community Distributed Generation

5. Process and Customer Protections
    a. The Company's CDG Operating Agreement details the format and requirements for CDG application submissions.
    b. Additionally, the Company's CDG Operating Agreement sets forth consumer protections required of CDG Hosts, which may be in addition to, or as modified by, the Uniform Business Practices for Distributed Energy Resource Providers, to be issued by the Commission.
    c. A CDG Host may not request termination or suspension of the Company's electric service to a CDG Satellite Account.
    d. Service under this Rule shall terminate if the Company is notified by the Commission that a CDG Host is no longer eligible; if the CDG Host withdraws from CDG participation; or if the Company terminates service to the CDG Host Account. In such cases, the Account Closure provisions set forth in Rule 13. shall apply.

6. Metering Requirement

See Rule 13.C, Distributed Energy Resources, for applicable metering requirements.

7. Calculation and Application of Credits
    1. The Company shall calculate credits in accordance with 4.) below for a customer that has completed Step 8 of the SIR Addendum-SIR or has installed Net Metered Generation Facility on or prior to March 9, 2017, for the life of the Net Metered Facility ("Existing").
    2. The Company shall calculate credits in accordance with 4.) below for a customer that installs a Net Metered Generation Facility and does not meet the date requirement in 1.) above (i.e., installed after March 9, 2017) for a period of up to 20 years from the project's in-service date ("Phase One NEM") if the customer has:
        a. made payment for 25% of its interconnection costs, or has its Standard Interconnection Contract executed if no such payment is required as of July 17, 2017, and
        b. prior to the Company exceeding its 28 MW capacity limit.
    3. The Company shall calculate credits in accordance with Rule 26.B, Value of Distributed Energy Resources, Value Stack, for a Net Metered Generation Facility that does not meet the requirements in 1.) and 2.) above.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

7. Calculation and Application of Credits (Cont'd)

4. Calculation and Application of:

a. Monetary Credits:
A CDG Host Account that is: demand-billed; or has farm waste electric generating equipment Facility Located and Used at its Premises; or has fuel cell electric generating equipment, shall receive monetary credits in a month where the Host Account has Excess Generation. The monetary credit shall first be applied to any outstanding charges on the Host Account's current electric bill.
   i. Excess Generation shall be converted to the equivalent monetary value at the per kWh rate applicable to the Host Account's service classification for a demand-billed customer that does not have farm waste electric generating equipment at its Non-Farm Location; or does not have fuel cell electric generating equipment.
   ii. Excess Generation shall be converted to the equivalent monetary value at the Company's Buy Back Service Classification No. 5 for a customer with farm waste electric generating equipment at its Non-Farm Location; or fuel cell electric generating equipment.

   Any remaining monetary credits shall be allocated to each Satellite Account in accordance with the CDG Host designation pursuant to Section 3 as each Satellite Account is billed.
   The monetary credit applied to the CDG Host Account shall not exceed the current electric delivery charges, and if applicable, Company supply charges.

   The monetary credit applied to each Satellite Account shall not exceed the current electric delivery charges, and if applicable, Company supply charges or Consolidated Bill charges from the ESCO.

b. Volumetric Credits:
All other CDG Hosts and their Satellites shall receive volumetric credits in a month where the Host Account has Excess Generation :
   i. Any Excess Generation from the CDG Host shall be allocated to each Satellite Account in accordance with the Host Account designation pursuant to Section 3.
   ii. As each Satellite Account is billed, excess kWh designated to the Satellite Account is converted to a monetary credit and applied to the per kWh charges on the Satellite Account and if applicable, Consolidated Bill charges from the ESCO. Monetary credits are calculated using the per kWh rate for the Service Classification applicable to the Satellite Account. If a credit remains after applying to the Satellite Account, the credit is converted back to kWh based on the per kWh rate for the Service Classification applicable to the Satellite Account.

c. If a monetary or volumetric credit remains after applying to the Satellite Account, the remaining credit shall remain on the Satellite Account until used. Satellite credits shall not expire at the end of an annual period.
d. Any unallocated credits or allocations retained at the CDG Host Account, will be combined with the next month's volumetric or monetary credits to be applied to the CDG Host Account and Satellite Accounts, as applicable.
e. If the CDG Host Account was previously established as a net metered customer-generator or Remote Net Metered Host, any outstanding credits shall be included in the CDG Host's first bill pursuant to this Rule.
f. If the Company is unable to obtain an actual meter read for Host Accounts, the Company shall not be required to estimate Excess Generation output for determining credits to be applied to CDG Satellites.
   i. CDG Host Accounts will be read every month.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

7. Calculation and Application of Credits

5. CDG Net Crediting Program

Effective April 1, 2021, a CDG Host that is compensated pursuant to Rule 26.B Value Stack may participate in the CDG Net Crediting Program as specified in this Rule 23.7.5. The CDG Net Crediting Program is an alternative payment and crediting methodology for CDG Hosts and CDG Satellites. Additional terms, conditions, definitions, and processes are set forth in the Community Distributed Generation Value of Distributed Energy Resources ("VDER" or "Value Stack") Procedural Requirements, including Net Crediting Manual ("CDG Value Stack Procedural Requirements") and posted on the company's website. The Net Crediting Program allows CDG Satellites to receive one bill from the Company with a Net Member credit in lieu of receiving an additional separate bill from the CDG Host. The Company shall remit payment to the CDG Host as described herein.

a. Enrollment and Subsequent Changes

CDG projects participating in the CDG Net Crediting Program must meet requirements as applicable to projects that are compensated pursuant to Rule 26.B. Value Stack and participated in Rule 23, CDG.

The CDG Host must enroll by executing a CDG Sponsor Net Crediting Agreement with the Company, at least sixty days prior to commencing participation in the CDG Net Crediting Program, in addition to any other forms and registrations required under Rule 23 and the Company's CDG Value Stack Procedural Requirements. An existing CDG Host may enroll their project on a first-come, first-serve basis at least sixty days prior to requesting participation in the CDG Net Crediting Program. Participation in Net Crediting shall become effective with the first CDG Host bill sixty days after all necessary enrollment forms have been received and approved by the Company.

i. The CDG Host must be current on their utility account tied to the CDG Host project to be eligible and participate in Net Crediting.

ii. The CDG Host shall provide the CDG Savings Rate(s) for the project to the Company as part of the enrollment process. Following the initial enrollment in the Net Crediting Program, the CDG Host may submit a request to update the CDG Savings Rate(s) on a monthly basis as set forth in the Company's CDG Value Stack Procedural Requirements.

a. The CDG Savings Rate(s) may not be less than 5% for any CDG project and no greater than 100% minus the Utility Administration Fee of 1%. Up to three different CDG Savings Rates (set in increments of percentages with a single decimal place) can be applied to all CDG Satellites of a CDG Project, except for Excluded Anchor Satellites, if applicable, as specified in 23.7.5.d. below.

b. The CDG Host may modify its CDG Savings Rate(s) or its associated CDG Satellite accounts and/or the allocation percentages of its CDG Satellites no less than 30 days prior to the CDG Host account's billing date to which the modifications apply.

c. Non-Value Stack CDG or RNM projects that opt into the CDG Net Crediting will forfeit any banked volumetric credits on the existing projects before commencing with the CDG Net Crediting program.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

7. Calculation and Application of Credits (Cont'd)
   5. CDG Net Crediting Program (Cont'd)

      a. Enrollment and Subsequent Changes (Cont'd)
         iii. CDG Hosts may remove the CDG project from the CDG Net Crediting Program with 30 days' notice prior to the CDG Host Account's cycle billing date to which the modifications apply. A CDG project that has been previously been removed from the CDG Net Crediting Program may re-enroll following at least one year from when they were removed from the CDG Net Crediting Program and shall be subject to the required sixty days' notice to re-enroll a CDG project as specified in a.i. above.
            a. CDG projects that have been removed from the CDG Net Crediting Program shall have the option to switch to Remote Crediting (Rule 35).

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)
7. Calculation and Application of Credits (Cont'd)

5. CDG Net Crediting Program (Cont'd)
   iv. If a CDG Host transfers ownership of a CDG project participating in the Net Crediting Program, and the new CDG Host requests to continue the Net Crediting, the CDG Host shall re-enroll the CDG project on sixty days' notice as described above.

b. Excluded Anchor Satellites
   i. The CDG Host may choose to designate multiple CDG Satellites to be an Excluded Anchor Satellite, limited in aggregate up to 40 percent of the total CDG Project's monthly allocation.
   ii. The Excluded Anchor Satellite(s) shall be a demand-billed, non-mass market Company electricity customer with demand greater than or equal to 25kW in the last twelve months.
   iii. The Excluded Anchor Satellite(s) may be identified on the CDG Net Credit Form when enrolling in Net Crediting at least 60 days prior to net crediting as an Excluded Anchor Satellite.
   iv. The CDG Host may change the designation of Excluded Anchor Satellite(s) as set forth in the CDG Value Stack Procedural Requirements.
   v. The CDG Savings Rate(s) shall not apply to the Applied Credits calculated for Excluded Anchor Satellite(s).
   vi. The CDG Subscription Fee shall not apply to Excluded Anchor Satellite(s).

c. Determination of CDG Satellite's Net Member Credits and CDG Subscription Fee
   i. The Company shall calculate and apply a Net Member Credit to the participating CDG Satellite's bill.
   ii. The Net Member Credit shall be determined as follows:
      a. For each billing period, the total credit allocated to the CDG Satellite shall be calculated pursuant to Rule 26.B.7.c, Value Stack Billing for net export injections. Banked Monetary Credit plus allocated Monetary Credits applied to electric charges ("Applied Credit") cannot exceed the CDG Satellite's electric bill.
      b. If there is remaining Monetary Credits, the credit shall be banked on the CDG Satellite's account for the subsequent billing period.
      c. The CDG's Satellite's Net Member Credit is equal to the Applied Credit times the CDG Savings Rate applicable to the CDG Satellite.
   iii. A CDG Subscription Fee will be calculated for all CDG Satellites, except the Excluded Anchor Customer(s), based on the Applied Credit each billing period. The CDG Subscription Fee is equal to the Applied Credit multiplied by a percentage of one minus the CDG Savings Rate.
   iv. A CDG Satellite, except the Excluded Anchor Customer(s), will receive a credit on their bill in the amount equal to the net credit.

d. Determination of CDG Host Payment
   The CDG Host Payment will be the sum of the CDG Subscription Fees calculated for each of the project's CDG Satellites in the applicable billing period less the Utility Administrative Fee.
   i. A Utility Administrative Fee is retained by the Company and is calculated using a discount rate of 1% of the total Applied Credit.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

8. Annual Allocation Requests

a. The CDG Host may choose to submit a one-time annual allocation request to fully distribute 100% of the excess Credits to its members.

i. The CDG Host may furnish to the Company an Annual Allocation request no less than 15 days prior to the Host's bill period starting in the Anniversary Month. An allocation is effective for a one-time allocation only and supersedes any other allocation requests for the anniversary month bill period.

a. The most recent Allocation Request in effect prior to the Annual Allocation Request shall continue to be applied to all on-going allocations unless a new Subsequent Allocation request is submitted.

If an Annual Allocation Request is not received, allocations shall be made in accordance to the allocation request in effect.

CDG Host Account shall have up to a two-year grace period following the CDG Host's Anniversary month to distribute any excess credits they retain at the end of the annual period.
If the CDG Host Account has any annual credits remaining at the end of the two-year grace period, it shall forfeit a number of credits equal to the smallest number of credits that were in the CDG Host's account at any point during the grace period.

A CDG Hosts shall only be permitted to retain credits for distribution during the two-year grace period if those credits remain after the Host has distributed as many credits as practicable to Satellite Accounts, such that each Satellite Account's consumption in the final month of the annual period has been fully offset.

9. Account Closures

a. CDG Host Account

If a CDG Host closes their account:

i. The Company shall require an actual meter reading to close an account pursuant to this Rule.

ii. The Company shall close an account on the earlier of:

(a) the first cycle date on which a reading is taken following the requested turn off date, or

(b) the date of a special reading, which a Customer may request at the charge specified in Charges for Special Services Statement.

iii. After a CDG Host account's final bill is rendered, any remaining banked credit shall not be transferred. However, a CDG Host with Farm Wind or Farm Waste electric generating equipment shall receive a final cash out at avoided cost.

iv. A CDG Host with remaining banked credit at the end of the project term (i.e., 20 years for unused Phase One NEM volumetric credits or 25 years for unused Value Stack monetary credits) shall forfeit such credit.

b. CDG Satellite Account

If a CDG Satellite closes their account:

i. The Company shall require an actual meter reading to close an account pursuant to this Rule.

ii. The Company shall close an account on the earlier of:

(a) the first cycle date on which a reading is taken following the requested turn off date, or

(b) the date of a special reading, which a Customer may request at the charge specified in the Charges for Special Services Statement.

c. Once the CDG Satellite has closed their account and the final bill rendered, the banked credits that were remaining on the CDG Satellite's account shall be transferred to the CDG Host Account.

d. Credits transferred to the CDG Host Account shall be transferred with no adjustments to the Market Transition Charge ("MTC") or Community Credit ("CC"), if applicable.

e. Once remaining credits have been transferred to the CDG Host of a project, the Company shall not be responsible for any additional refunds or credits owed to the CDG Satellite Account for that CDG project.

GENERAL INFORMATION

23. Community Distributed Generation (Cont'd)

10. Discontinuance of Participation in CDG Project

If a CDG Satellite discontinues participation in a CDG project:

a. The Company shall rely on the CDG Host's monthly allocation form to verify the CDG Satellite Account's participation in the CDG Host's project. When the Company processes the CDG allocation form that no longer includes the CDG Satellite Account, the Company shall transfer any banked credits of the CDG Satellite Account to the CDG Host Account.
b. Credits transferred to the CDG Host Account shall be transferred with no adjustments to the Market Transition Charge ("MTC") or Community Credit ("CC"), if applicable.
c. Once remaining credits have been transferred to the CDG Host of a project, the Company shall not be responsible for any additional refunds or credits owed to the CDG Satellite Account for that CDG project.
d. A CDG Satellite Account that has been removed from a CDG Host project, but continues to maintain an active utility account, may not subscribe to a new CDG Host or CDG Net Crediting project until the billing period after which all banked credits are returned to the original CDG Host's Account.

11. Liability

Notwithstanding any other provision of this tariff, in case the supply of service shall be interrupted or irregular or defective or fail from causes beyond the Company's control (including without limiting the generality of the foregoing executive or administrative rules or orders issued from time to time by State or Federal officers, commissions, boards or bodies having jurisdiction), or because of the ordinary negligence of the Company, its employees, servants or agents, the Company shall not be liable therefore.

12. One-Time Voluntary Switch:

A customer shall have the option to make a one-time voluntary switch from CDG to Remote Crediting (Rule 35). The procedure to switch is detailed in the CDG VDER Procedural Requirements manual posted on the Company's website.

a. A customer shall provide the Company with notice of their intent to switch and submit a switching certification and a CDG/Remote Crediting allocation form within 60 days of the new project's first account billing date or within 45 days of the existing project's last host account billing date.
    (i) The project shall remain under the Value Stack compensation mechanism as described in Rule 26.B.10.
    (ii) This switch shall be irrevocable.
b. If a customer chooses to make a one-time voluntary switch, the component rates that were established on the customers eligibility date shall not change and all project elections shall carry forward.
c. The compensation term shall be that of the program that a customer is switching into and begins on the project's original interconnection date.
d. The customer shall retain any monetary credits banked on the host account; this shall be the starting balance of the new host bank.
e. For projects switching to Remote Crediting and choose to receive compensation under the Environmental Component, the project owner shall contact the NYGATS administrator to initiate a transfer of the generator in NYGATS to the Company. Projects not already authorized in NYGATS must authorize the Company to register and report data through NYGATS.

GENERAL INFORMATION

24. RATE ADJUSTMENT MECHANISM ("RAM")

1. Applicable to all customers taking electric delivery service.

2. RAM Eligible Deferrals and Costs:
   The RAM will contain two types of eligible deferrals and costs:
   a. Type 1 - Customer Bill Credits
      The RAM will collect the customer bill credits provided to customers as a result of Covid-19 over a five-year period beginning July 1, 2021. The annual collection will be determined by dividing the total amount to be collected by the number of years remaining in the five-year period.
   b. Type 2 – Other RAM Eligible Deferrals and Costs
      All RAM Eligible Deferrals and Costs shall be the difference between actual costs and the amounts provided for in base rates. RAM Eligible Deferrals and Costs shall include:
      i. Property Taxes;
      ii. Major Storm Deferral Balances;
      iii. Reforming the Energy Vision ("REV") costs and fees which are not covered by other recovery mechanisms;
      iv. Costs associated with the implementation of any Commission-ordered Electric Vehicle Program which recovery is not provided for by any other cost recovery mechanisms; and
      v. Excess energy efficiency and heat pump costs (after first allocating the annual unspent funds to the amount).

   All RAM revenues and deferrals are subject to reconciliation.

3. Annual RAM Recovery / Return Limits:
   a. The annual RAM recovery / return shall be limited to $12.1 million for electric and include Type 1 and Type 2:
      i. Type 1 – Customer bill credits will be collected annually beginning July 1, 2021 (over a five year period).
      ii. Type 2 – Other RAM Eligible deferrals and costs will only be implemented once the limit is reached from netting the RAM Eligible Deferrals.

   Any net RAM Eligible Deferral value in excess of the limit shall remain deferred and shall be carried forward to the calculation of the RAM limits in the following year. Any net regulatory asset or liability in excess of the Company's annual RAM recovery / return limit shall be carried forward to the calculation of the RAM in the following year.

4. Deferred Regulatory Asset and Liability Balances:
   The Company shall measure the deferred regulatory asset and liability balances for the items specified as Type 2 – Other RAM Eligible Deferrals and Costs (listed above) as of December 31 for each year. The RAM shall be identified in the Company's respective RAM Compliance Filings submitted on March 31 of each year and shall be implemented in rates on July 1 of each year for collection over the 12 months from July 1 to June 30. The RAM Compliance Filings will include proposed RAM rates by service classification. Annually, the Company will submit RAM tariff statements effective on July 1.

GENERAL INFORMATION

24. RATE ADJUSTMENT MECHANISM ("RAM") (Cont'd)

5. RAM Annual Recovery / Return Allocation:
The electric RAM annual recovery / return amounts shall be allocated to service classifications based on the following:
    a. Type 1 - Customer Bill Credits
    Shall be recovered from those service classes which were eligible to receive the customer bill credits. Specifically, residential classes will be charged for the recovery of the residential bill credits and applicable non-residential service classes will be charged for the recovery of the non-residential bill credits. The Company will not recover customer bill credits from service classes that are not eligible for the bill credits. Recovery will occur on a per kwh basis for non-demand customers, on a per kw basis for demand billed customers and on an As-Used Demand basis for Standby customers.
    b. Type 2 – Other RAM Eligible Deferrals and Costs
        i. Deferrals and Costs identified in 24.2 above as Type 2 (i.) through Type 2 (iv.) shall be allocated based on delivery service revenues and recovered on a per kWh basis for non-demand customers, on a per kW basis for demand billed customers, and per As-Used Demand basis for Standby customers.
        ii. Type 2 (v.) costs shall be allocated to service classes consistent with how the energy efficiency and heat pump program costs are allocated in base rates.

6. Carrying Costs:
The Company shall accrue carrying costs on Type 1 – Customer Bill Credits based on the Commission's authorized Other Customer Capital Rate.

The Company shall accrue carrying costs on Type 2 – Other RAM Eligible Deferrals and costs as follows:
    a. During the period that the RAM is in effect for those deferral balances being specifically collected or returned, carrying costs shall be based on the Commission's authorized Other Customer Capital Rate.
    b. RAM Eligible Deferral Balances not in the RAM tariff due to the annual dollar amount restrictions set forth above shall accrue carrying charges as follows:
        i. Net Deferral amounts at or under the annual RAM recovery / return limits shall accrue carrying charges at the Other Customer Capital Rate;
        ii. Additional deferral amounts over the annual RAM recovery / return limits, up to one year's worth of value, shall accrue carrying costs at the Other Customer Capital Rate; and
        iii. Additional deferral amounts over the annual RAM recovery / return limits in Rule 24.6.b.i and b.ii above, shall accrue carrying costs at the Company's respective Pre-Tax Weighted Cost of Capital, applied to the after-tax balance.

7. Filings and Statements:
    a. A RAM Compliance Filing setting forth the RAM rates by Service Classification shall be filed with the Commission by March 31 on an annual basis.
    b. A RAM Statement setting forth the RAM rates shall be filed with the Commission on not less 30 days' notice to be effective July 1. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

25. Clean Energy Standard ("CES")

A. The Clean Energy Standard (CES) surcharge recovers costs associated with the procurement of Renewable Energy Credits (RECs) that supports generation by renewable sources; the purchase of Zero-Emission Credits (ZECs) that supports qualified zero-emissions nuclear power plants; the benefits and costs associated with the sale and transfer of Tier 1 VDER RECs as described in 25.A.i; and costs associated with Alternative Compliance Payment (ACPs), if applicable, for any shortage of RECs needed for the Company to meet its obligations from Non-Retail Access customers.

i. The Company shall be permitted to sell excess Tier 1 VDER RECs to other New York investor-owned utilities at the same price the Company initially paid for the REC during the 2023 and 2024 CES compliance periods.

The Clean Energy Standard (CES) also recovers costs associated with contracts signed by NYSERDA to maintain certain baseline renewable resources at risk of attrition (Tier 2 Maintenance Contracts); cash shortages that may have resulted from NYSERDA's CES activities and cash shortages associated with the procurement of Offshore Wind generation (OSW) (Backstop Charges); through the System Benefits Charge (SBC) from all customers, including those customer with energy usage that is exempt from the SBC.

B. RECs, ZECs, and if applicable, ACPs, shall be recovered from all Non-Retail Access customers through the Supply Adjustment Charge Component as set forth in General Information Rule 12,

i. The costs for the RECs shall be recovered by dividing the annual REC costs, including an allowance for uncollectibles, by projected kWh sales and adding to the Supply Adjustment Charge Component.
   a. REC costs shall be reconciled on an annual basis.

ii. The costs for the ZECs shall be recovered by dividing the annual ZEC costs, including an allowance for uncollectibles, by projected kWh sales and adding to the Supply Adjustment Charge Component.
   a. ZEC costs shall be reconciled on an annual basis.

iii. The costs for the ACP shall be recovered by dividing the annual ACP costs, including an allowance for uncollectibles, by projected kWh sales and adding to the Supply Adjustment Charge Component.
   a. ACP costs shall be reconciled on an annual basis.

C. Tier 2 Maintenance Contracts and Backstop Charges shall be recovered from all customers through the System Benefits Charge as described in Rule 4.K.

D. The Company shall file a CES Statement on not less than 15 days' notice. The Statement shall set forth the surcharge rates as described in Rule 25.B. above.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER")

A. Phase One Net Energy Metering ("NEM")

1. Eligible Technologies
   a. Any customer, residential or non-residential, who owns or operates electric generating equipment ("Facility"), as defined in Public Service Law ("PSL") §66-j and §66-l, limited in size in conformance with the statute for each facility type and customer type that generates electric energy. A Customer that meets the requirements of 2.b.i or 2.b.ii below shall be permitted to include energy storage technology with their Facility and remain eligible for Phase One NEM.
      i. To qualify for net metering, the Customer Generator must comply with the requirements of the generating size limits (solar generating equipment up to 2 MW generation capacity limit) by complying with the following criteria:
         1) Each project up to the respective generating size limit must be separately metered and separately interconnected to the utility grid.
         2) Each project must be located on a separate site which can be accomplished by a project having a separate deed or a unique Section-Block-Lot (SBL), a separate lease, and a separate metes and bounds description recorded via either a deed or separate memorandum of lease uniquely identifying each project.
         3) Each project must operate independently of other units.
   b. A DER provider shall comply with the requirements set forth in the UBP-DER Addendum.
   c. A customer exporting to the NYISO wholesale market pursuant to Wholesale Distribution Service is ineligible for Phase One NEM. A customer may opt-in to Rule 26.B Value Stack subject to the provisions therein.

2. Customer Project Qualification
   a. A customer taking service pursuant to Rule No. 13 may opt to take service under this Rule. Such election shall be a one-time election and shall be irrevocable.
   b. Phase One NEM shall be available to a customer with a project interconnected on or after March 10, 2017 and to projects for which Standard Interconnection Requirement Step 4 (for projects 50kW or less) or Step 8 (for projects greater than 50kW), as applicable, was not completed by March 9, 2017 as follows:
      i. Mass market on-site projects, defined as projects located behind the meter of a residential or small commercial customer that is not billed based on demand, that are not used to offset consumption at any other site.
      ii. Large on-site projects, defined as projects located behind the meter of a non-residential customer that is billed based on demand or subject to the provisions of the Company's Hourly Pricing Provision, that are not used to offset consumption at any other site for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, on or before July 17, 2017;
      iii. A project eligible for Remote Net Metering pursuant to Rule 28 for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, on or before July 17, 2017; and
      iv. A project eligible for Community DG pursuant to Rule 23 for which 25% of interconnection costs have been paid, or a Standard Interconnection Contract has been executed if no such payment is required, on or before July 17, 2017, up to a total rated generating capacity of 28 MW. In the event that capacity remains below this threshold which would accommodate a portion of an eligible project, the provisions of this Rule shall be available to the entire project.
      v. A project that has a rated capacity of 750 kW or lower; is sited at the same location and behind the same meter as the electric customer whose usage the project is designed to off-set; and has an estimated annual output less than or equal to that customer's historic annual usage in kWh.
   c. A customer installing a Facility that does not meet the requirements in 2.a and 2.b above shall refer to Rule 26.B. Value Stack.
   d. Projects eligible for Phase One NEM may opt for compensation pursuant to Rule 40.B Value Stack. Such election shall be a one-time election and shall be irrevocable.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)

A. Phase One Net Energy Metering ("NEM") (Cont'd)

2. Available to (Cont'd):

e. A customer (Host Account) that meets the requirements of 2.a.iii. or 2.a.iv. above shall be permitted to designate non-metered account(s) as a Satellite Account if the Host Account is being compensated based on a monetary crediting methodology under this Rule, Value of Distributed Energy Resources ("VDER").

3. Billing

a. A customer that meets the requirements of 2.a or 2.b Customer Project Qualification above, shall be permitted to elect their service classification from the options below once per year on the customer's selected anniversary date. If a customer does not make a selection for their service classification, the default shall be the customer's standard otherwise applicable service classification.
   1. The customer's standard otherwise applicable service classification;
   2. Time-of-Use service classification, if available; or
   3. Standby Service

b. If a customer selects Standby Service, the customer will no longer be eligible for Phase One NEM, however such customer will be compensated under Rule 26.B Value Stack.

c. For each billing period during the term of the SIR Contract, the Company shall net the electricity (kWh) delivered to the customer with the electricity (kWh) supplied by the customer to the Company.

d. The Company shall calculate credits in accordance with Billing provision in Rules 14, 15, 16, 18, 19, or 20 as applicable to the type of Facility, for a period of 20 years from the project's in-service date, except for customers that are grandfathered pursuant to Rule 28 for Remote Net Metering. Such grandfathered customers shall be permitted to complete their term in accordance with the Special Provision.

e. The value of any credit remaining on a customer's account for excess electricity produced by the customer-generator (Facility) shall continue to carry over to the next monthly billing period. Any unused credits at the end of project's compensation term shall be forfeited.

f. A customer that meets the requirements of 2.b.i above, and is interconnected on or after January 1, 2022, may be subject to the Customer Benefit Contribution ("CBC") Charge as described in Special Provision 1 of Rule 26.C.
   1. The credits for net injections shall not be applied to the Customer Benefit Contribution ("CBC") Charge, if applicable, described in Special Provision 1 or Rule 26.C.

g. The Company shall calculate a customer's bill based on the service classification option selected, less any credits calculated for net injections, plus the Customer Benefit Contribution ("CBC") Charge, if applicable,
   1. Projects served under the Community Distributed Generation ("CDG") or Remote Crediting programs, shall not be subject to the CBC Charge.

4. Compensation Term

a. The compensation period will be in effect for 20 years from the project's in-service date, except for customers that are grandfathered pursuant to Rule 28 for Remote Net Metering. Such grandfathered customers shall be permitted to complete their term in accordance with the Special Provision.

b. A change in ownership shall not affect the compensation term.

5. Metering

a. The Company shall install metering appropriate for the customer's service classification that enables the Company to measure the electricity delivered to the customer and measure the electricity supplied by the customer to the Company for a customer that meets the requirements of 2.b.i or 2.b.ii above.

b. For all other projects, the Company shall install metering capable of recording net hourly consumption and injection for a customer. The customer shall be responsible for the cost of the meter, the installation, and any additional costs.

c. Where the Company determines that a second meter should be installed, no additional costs shall be billed to the customer. When a second meter is requested by the customer that is not required by the Company, the customer shall be responsible for the cost of the meter, the installation and any additional costs including the cost of providing telecommunication ability necessary for the communication between RG&E and the meter.

GENERAL INFORMATION

26. Value of Distributed Energy Resources (“VDER”) (Cont’d)

A. Phase One Net Energy Metering (“NEM”) (Cont’d)

6. Interconnection
   a. Customers electing service under this provision must operate in compliance with standards and requirements set forth in the Distributed Generation Interconnection Requirements found in P.S.C. No. 19, Section 10 and Addendum-SIR to P.S.C. No. 19. In addition, customers must execute the New York State Standardized Contract For Interconnection of New Distributed Generation Units With Capacity of 5 MW or Less Connected in Parallel with Utility Distribution Systems ("SIR Contract"), as contained within Addendum-SIR of P.S.C. No. 19.
   b. The customer shall be responsible for costs for a dedicated transformer(s) or other equipment, should it be deemed necessary by the Company, pursuant to the Addendum-SIR to P.S.C. No. 19. In the event that the total rated generating capacity of electric generating equipment that provides electricity to the Company through the same local feeder line exceeds twenty percent of the rated capacity of the local feeder line, the customer owning or operating such equipment may be required to comply with additional measures to ensure the safety of the local feeder line.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)

B. Value Stack:

1. Eligibility:

a. i. Any customer, residential or non-residential, who owns or operates electric generating equipment ("Facility"), as defined in Public Service Law ("PSL") §66-j or PSL§66-l, limited in size as set forth in the table below:

Generator Type	**Size Limit on System**	
	Residential	**Non-Residential**
Solar	Up to 5 MW	
Micro-hydroelectric	Up to 5 MW	
Fuel Cell	Up to 5 MW	
Micro-CHP	10 kW	N/A
Farm Waste	Up to 5 MW	
Wind	Up to 5 MW	
Farm Wind	Up to 5 MW	

ii. A customer may install stand-alone energy storage equipment, including an electric vehicle ("EV") charged using regenerative braking technologies, and vehicle-to-grid ("V2G") or vehicle-to-grid integration ("VGI") systems, or pair with a Facility when submitting an application for net metering pursuant to this Rule 26.B.

iii. Technologies eligible for the Clean Energy Standard Tier 1 ("CES Tier 1"), as listed in Appendix A of the Commission's Order Adopting A Clean Energy Standard, issued on August 1, 2016 in Case 15-E-0302, including projects utilizing the same technology as defined for CES Tier 1 that were installed and operational by January 1, 2015, up to 5 MW in size, are eligible for compensation under this Rule as provided herein.

iv. To qualify for net metering, the Customer Generator must comply with the requirements of the generating size limits by complying with the following criteria:

1) Each project up to the respective generating size limit must be separately metered and separately interconnected to the utility grid.

2) Each project must be located on a separate site which can be accomplished by a project having a separate deed or a unique Section-Block-Lot (SBL), a separate lease, and a separate metes and bounds description recorded via either a deed or separate memorandum of lease uniquely identifying each project.

3) Each project must operate independently of other units.

b. A customer taking service pursuant to Rule No. 13 or Rule 26.A, Phase One NEM may opt to take service under this Rule. Such election shall be a one-time election and shall be irrevocable.

i. An existing customer with a Facility that is sized less than 2 MW may have the capability, based on existing design and location, to increase the capacity of the Facility up to 5 MW. If an existing customer chooses to increase the size of its Facility, the Facility shall receive compensation pursuant to the Value Stack for the entire project.

ii. An existing customer taking service pursuant to Rule 23, Community Distributed Generation, that chooses to increase the capacity of their Facility greater than 2 MW, up to 5 MW, may be assigned to a new Tranche as described in Rule 26.B.6.vi.

c. A customer with an existing generator sized between 2 MW and 5 MW, that otherwise meets the eligibility requirements pursuant to PSL §66-j or PSL§66-l and herein, taking service pursuant to Service Classification No. 10; or receives compensation through bilateral contracts or the NYISO; may make a one-time irrevocable election to opt to take service pursuant to their otherwise applicable Service Classification and receive compensation for excess generation pursuant to this Rule, 26.B. Value Stack.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)

B. Value Stack:

1. Eligibility (Cont'd):

d. A customer with a generator that otherwise meets the eligibility requirements above in 1.a., and taking service pursuant to Service Classification No. 5, Buy-Back Service; or Service Classification No. 14, Standby; may opt to receive compensation for net hourly injections pursuant to this Rule, 26.B. Value Stack to the extent the customer is not being compensated for such net hourly injections through the wholesale market.

i. A customer taking service pursuant to Service Classification No. 14, Standby; and opting for Value Stack compensation, will be excluded from receiving the Reliability Credit under Service Classification No. 14.

e. Expansion or Consolidation Projects Under Development
Interconnection applications for new projects sized between 2 MW and 5 MW, proposals to increase the capacity of existing projects, and proposals to increase the capacity of projects currently in the interconnection queue may be submitted to the Company. If Tranche limits are exceeded, Projects currently in the interconnection queue may not be consolidated until further consideration and action on proposed SIR changes has been taken by the Commission.

f. A customer taking service pursuant to this Rule shall be required to install metering equipment capable of recording hourly net consumption and net injections.

g. A DER Provider shall comply with the requirements set forth in the UBP-DER Addendum.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER"): (Cont'd)
   B. Value Stack: (Cont'd)

2. Applicable To:
   The Value Stack shall be applicable to a customer interconnecting a Facility that is:
   (a) not eligible for Grandfathered Net Metering as set forth in Rule 28 for Remote Net Metering; or
   (b) is not eligible for Phase One NEM as set forth in Rule 26.A; or
   (c) has made a one-time irrevocable election to opt-in to the Value Stack; or
   (d) participating in the Remote Crediting Program as described in Rule 35.
3. Definitions:
   a. "Mass Market Customer": a customer billed pursuant to a residential service classification or a small commercial customer that is not billed based on demand and whose electric generating equipment supplies energy to a single account behind the same meter as the generating equipment.
   b. "Net injection" or "Net hourly injection" is the amount of excess energy produced by a customer's electric generating equipment beyond the customer's usage that is fed back to the Company's system for a customer served under the Value Stack Tariff.
   c. "Renewable energy systems": systems that generate electricity or thermal energy through use of the following technologies: solar thermal, photovoltaics, on land and offshore wind, hydroelectric, geothermal electric, geothermal ground source heat, tidal energy, wave energy, ocean thermal, and fuel cells which do not utilize a fossil fuel resource in the process of generating electricity.
4. Compensation:
   a. The Company shall calculate the credit by multiplying the Value Stack Components, as applicable, by the net export net hourly injections to determine the total value of the credit.
      i. The total value of the credit shall be applied to any outstanding charges on the customer's current electric bill, except for the Customer Benefit Contribution ("CBC") charge as described in Rule 26.B.7 Value Stack Billing.
   b. Projects that qualified for Value Stack compensation before July 27, 2018, excluding Community DG projects and any projects receiving the MTC Component, are allowed a one-time, irrevocable election to receive compensation for the Capacity Component, DRV Component, and LSRV Component (if applicable), that is applicable to projects that qualified on or after July 27, 2018. This election must be for all components applicable to the project.
   c. The credit values shall be set forth on the VDER-Cred Statement and filed on not less than one days' notice.
5. Cost Recovery:
   The Company shall recover the costs for the credits paid to customers for each of the Value Stack Components pursuant to Rule 12.B.1, Transition Charge and the Supply Adjustment Charge pursuant to Rule 12.C. Commodity Charge. The cost values shall be set forth on the VDER CR Statement and filed on not less than one days' notice.
6. The Value Stack Components:
   i. Value Stack Energy Component
      The compensation for energy under this provision shall be calculated based on the Facility's hourly metered net generation and the hourly energy price. The hourly energy price is the New York Independent System Operator (NYISO) Day-Ahead Market (DAM) Location Based Marginal Price (LBMP) for the Zone in which the Facility is electrically connected, adjusted for system losses. The DAM LBMP prices shall be the initial published DAM LBMP prices acquired by the Company. The credit for the Facility shall not be recalculated if such prices are modified by the NYISO at a later date.
      a. A customer taking service pursuant to Rule 26.C.2 (WVS) is ineligible to receive the Value Stack Energy Component.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER"): (Cont'd)
    B. Value Stack: (Cont'd)

    ii. Value Stack Capacity Component
        i. The capacity component is determined from the NYISO's monthly and spot capacity auctions for the capacity zone in which the customer-generator is electrically connected.
        ii. A customer-generator with intermittent generation (i.e., solar or wind electric generating equipment) shall select from the following Alternatives in Section 5. below for calculating the compensation of the Value Stack Capacity Component ("Capacity Compensation"). If no selection is made, the Capacity Compensation shall default to Alternative One. A customer-generator with dispatchable generation (i.e., all other electric generating equipment served under this Rule) shall be required to receive Capacity Compensation under Alternative Three.
        iii. A customer-generator with an eligible CES Tier 1 technology, as provided in 26.B.1.a.iii, shall be required to receive capacity compensation under Alternative Three.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)
    6. The Value Stack Components: (Cont'd)
        ii. Value Stack Capacity Component (Cont'd)

iv. A customer-generator with intermittent generation (i.e., solar or wind electric generating equipment) may submit a request for a change in compensation as follows:

a. Compensation under Alternative 1 may switch to compensation under Alternative 2 or to Alternative 3;
b. Compensation under Alternative 2 may switch to Alternative 3.
c. A project compensated under Alternative 2 may not switch to Alternative 1, and a project compensated under Alternative 3 may not switch to Alternative 1 or Alternative 2.

v. Should the NYISO adjust the New York Control Area peak to reflect capacity provided by customer generation, the Company shall adjust the Value Stack Capacity Component for each of the Alternatives accordingly.

vi. Alternatives for Capacity Compensation
a. Alternative One:
i. For a customer that has met the eligibility requirements of Rule 26.B.1. and 26.B.2. above prior to July 27, 2018, the capacity credit shall be equivalent to the Capacity Component as calculated pursuant to Rule 12.C for Service Classification No. 7 multiplied by the net export generation of the Facility for the billing period.
ii. A customer meeting the eligibility requirements of Rule 26.B.1. and 26.B.2. on or after July 27, 2018, the capacity credit compensation shall equal the monthly NYISO $/kW-month auction price adjusted for the NYISO UCAP Effective Percentage and the NYISO Demand Curve Adder percentage multiplied by a capacity factor divided by the monthly kWh/kW multiplied by the net export generation of the Facility for the billing period. If the capacity factor is not known, the Company shall use a proxy capacity factor.

b. Alternative Two:
i. For a customer that has met the eligibility requirements of Rule 26.B.1. and 26.B.2. above prior to July 27, 2018, the capacity credit shall use the capacity costs calculated under Alternative One, however, the costs used to develop the credit are concentrated over the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August. The resulting rate per kWh will be multiplied by the net export generation of the project in those 460 hours. The credit is assumed to be zero in the hours and months not identified herein. A customer-generator must elect Alternative 2 by May 1st to be eligible to receive Value Stack Capacity Component via this alternative beginning June 1st of that summer. A customer-generator electing Alternative 2 after May 1st will remain on Alternative One until April 30th of the following calendar year.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)
    6. The Value Stack Components: (Cont'd)
        ii. Value Stack Capacity Component (Cont'd)
            vi. Alternatives for Capacity Compensation (Cont'd)
                b. Alternative Two: (Cont'd)
                    ii. A customer meeting the eligibility requirements of Rule 26.B.1. and 26.B.2. on or after July 27, 2018, the capacity credit shall be the sum of the 12 monthly NYISO $/kW-month auction price adjusted for the NYISO UCAP Effective Percentage and the NYISO Demand Curve Adder percentage for the months that make up the previous NYISO Capacity Year (May through April) divided by the number of hours between Hour Beginning 2:00 PM and Hour Beginning 6:00 PM inclusively on non-holiday weekdays from June 24 to September 15. That number of hours will be either 240 or 245 depending on the year. The resulting credit per kwh will be multiplied by the net energy exported adjusted for the appropriate energy losses for the customer's service class during the hours between Hour Beginning 2:00 PM and Hour Beginning 6:00 PM inclusively on non-holiday weekdays from June 24 to September 15.

                c. Alternative Three: shall be equivalent to the customer-generator's service classification capacity cost and shall be calculated by multiplying the customer-generator's net energy export during the New York Control Area peak of the previous calendar year by the customer's capacity component based on their Facility's net export generation.

            vii. The Capacity Component shall be set forth on the VDER-Cred Statement.

            viii. A customer taking service pursuant to Rule 26.C.2 (WVS) is ineligible to receive the Value Stack Capacity Component.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)
        6. The Value Stack Components: (Cont'd)

iii. Environmental Component:

1. A Facility opting into the Value Stack shall receive the Environmental Component compensation for renewable attributes except for those that opt to receive compensation through the Renewable Portfolio Standard, including the Maintenance Tier, or through Tier 2 of the Clean Energy Standard.
    a. Eligible CES Tier 1 projects built before 1/01/2015, shall not be eligible for Environmental Component compensation.
    b. A Facility that does not meet the definition of a Renewable Energy System and qualifies for Value Stack compensation after August 13, 2019, shall not be eligible to receive the Environmental Component.
2. The compensation for the Environmental Component shall be fixed at the time the customer-generator satisfies the 25% interconnection cost responsibility set forth in the Addendum-SIR, or where no such obligation is required, at the time the interconnection agreement is signed and calculated by multiplying the total net export generation for the billing period by the customer-generator onto the Company's system by the Environmental Component rate.
3. A customer receiving compensation for the Environmental Component shall transfer ownership of the RECs to the Company.
4. The Environmental Component shall be fixed for the term of compensation for the Facility. The Environmental Component shall be provided on the VDER-Cred Statement.

iv. Demand Reduction Value ("DRV") Component:

a. A credit shall be provided for the Facility's potential contribution to the distribution system.
b. For a customer that has met the eligibility requirements of Rule 26.B.1. and 26.B.2. above prior to July 27, 2018, DRV Component compensation shall not be provided for the portion of the project that receives a Market Transition Credit ("MTC") as described in Rule 26.B.6.vi.
    i. The DRV Component shall be fixed at the time the customer-generator pays 25% of the interconnection cost, or where no such payment is required, at the time the interconnection agreement is signed and then fixed for a period of ten years from a project's date of interconnection. The DRV may be adjusted every three years from a project's date if interconnection for the rest of the project's term of compensation pursuant to this Rule.
c. A customer meeting the eligibility requirements of Rule 26.B.1. and 26.B.2. on or after July 27, 2018, the DRV credit shall be applied to all net energy exported between Hour Beginning 2:00 PM and Hour Beginning 6:00 PM inclusively on non-holiday weekdays from June 24 to September 15. The credit per kwh will be determined by multiplying the $/kW-year values established by the most recent Commission-approved marginal cost study by 10 years and dividing the result by the total number of hours between Hour Beginning 2:00 PM and Hour Beginning 6:00 PM inclusively on non-holiday weekdays from June 24 to September 15 for the previous 10 year period.
d. As provided in Rule 4.S., Commercial System Relief Program ("CSRP"), a customer may make a one-time irrevocable election to participate in the CSRP instead of receiving DRV and LSRV compensation, regardless of when the project qualified for Value Stack compensation.
e. As provided in Rule 31, Term and Auto-Dynamic Load Management Programs, a Value Stack customer may participate in Term-DLM and Auto-DLM programs, provided that such customer does not receive DRV or LSRV compensation during the term of their participation in the Term-DLM and Auto-DLM Programs.
f. The DRV Component shall be set forth on the VDER-Cred Statement.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    - B. Value Stack: (Cont'd)
        6. The Value Stack Components: (Cont'd)

v. Locational System Relief Value ("LSRV") Component: A customer that interconnects their Facility in pre-identified locations shall receive a LSRV credit.

a. For a customer that has met the eligibility requirements of Rule 26.B.1. and 26.B.2. above prior to July 27, 2018:

i. A credit per kW shall be provided for the Facility's potential contribution to the distribution system if the Facility is interconnected on a circuit designated for LSRV compensation.

ii. Compensation for the LSRV Component shall be fixed at the time the customer-generator satisfies the 25% interconnection cost responsibility set forth in the Addendum-SIR, or where no such obligation is required, at the time the interconnection agreement is signed and then fixed for a period of 10 years from the time the project's date of interconnection.

iii. The LSRV may be adjusted every ten years.

iv. The pre-identified locations and LSRV Component shall be set forth on the VDER-Cred Statement.

b. A customer meeting the eligibility requirements of Rule 26.B.1. and 26.B.2. on or after July 27, 2018, the LSRV compensation will be based on the project's response to Company-called events ("LSRV Call Events").

i. The compensation for each LSRV Call Event will be: i) the project's lowest hourly net kW injection during the LSRV Call Event; multiplied by ii) the project's applicable LSRV Call Component rate as set out below.

ii. The project's applicable LSRV Call Component rate ($/kW) will be the project's applicable LSRV Component rate ($/kW-mo.), as specified below, multiplied by 12 (months) and divided by 10 (annual minimum calls per year).

iii. The project's applicable LSRV Component rate ($/kW-mo.) will be determined as the LSRV rate ($/kW-mo.), as filed by the Company in a statement with the Commission in effect at the time of the project's Eligibility Date and will be fixed for the first ten (10) years from the project's interconnection date.

iv. For eligible CDG projects, the LSRV Component will be determined for each satellite by multiplying the project's applicable LSRV Component rate ($/kW-mo.) by the satellite's allocation percentage in effect for the Billing Period as provided by the CDG project sponsor. The LSRV Component associated with any Unallocated Satellite Percentage will be banked for later distribution by the CDG host.

c. LSRV Call Events:

i. The Company will call LSRV Call Events at least 21 hours in advance of the start of the LSRV Call Event.

ii. Each LSRV Call Event will be between one (1) hour and four (4) hours in duration.

iii. LSRV Call Events will generally be within the hours of 2:00 pm to 7:00 pm on non-holiday weekdays between June 24 and September 15. The Company reserves the right to call LSRV Call Events outside of those hours if system needs warrant.

iv. The Company reserves the right to combine LSRV areas into up to four (4) LSRV groups with different four (4)-hour call windows, each of which may be called independently based on sub-system load conditions.

v. The Company will call a minimum of ten (10) LSRV Call Events per year for each LSRV area or group but may issue more depending on system needs. Compensation level for all calls will remain at the same level regardless of frequency.

d. As provided in Rule 4.S., Commercial System Relief Program ("CSRP"), a customer may make a one-time irrevocable election to participate in the CSRP instead of receiving DRV and LSRV compensation, regardless of when the project qualified for Value Stack compensation.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
  B. Value Stack: (Cont'd)
    6. The Value Stack Components: (Cont'd)
      vi. Market Transition Credit ("MTC"):
        a. The MTC shall only apply to CDG projects (Rule 23) and Statewide Solar For All ("S-SFA") projects (Rule 39) with an eligibility date on or before July 26, 2018 which also meet the further requirements specified herein. The MTC shall be applicable to the Mass Market customers opting into Value Stack and to projects participating in CDG pursuant to Rule 23 with Mass Market subscribers. The MTC shall be applied to the mass market allocation of their net energy export as determined by the project's Tranche assignment and the customer's Service Classification. Non-mass market subscribers may receive a MTC that has been reallocated by a CDG Host Account pursuant to Rule 23
          i. For CDG projects, the MTC Component shall be calculated for each individual mass market satellite customer by multiplying: a) the sum of the project's total net injections for the billing period (kWh), b) the MTC Component rate applicable to the project's assigned tranche and satellite's service class, and c) the satellite's allocation percentage in effect for the Billing Period as provided by the CDG Host. The CDG Host will not be allowed to bank any MTC components related to Unallocated Satellite Percentages. CDG projects receiving MTC compensation cannot opt-into receiving the Community Credit component, as described below.
          ii. For a CDG project that includes a dispatchable high capacity factor resource, *i.e.*, a Fuel Cell, and qualified for Value Stack compensation after August 13, 2019, any applicable MTC shall by adjusted by a factor of 0.16. A CDG project with a dispatchable high capacity factor resource, *i.e.*, a Fuel Cell, and qualified for Value Stack compensation on or before August 13, 2019 shall receive an unadjusted applicable MTC.
          iii. For eligible S-SFA Projects, the MTC Component shall be equal to the MTC SC No. 1 Component Rate applicable to the customer-generator's assigned Tranche multiplied by the sum of the project's total net injections for the billing period (kWh).
        b. A residential customer installing generation greater than 25 kW in size for Solar and Micro-hydroelectric, or 10 kW in size for Fuel Cell and Wind; or a customer-generator that is installing an eligible CES Tier 1 technology as provided in 26.B.1.a.iii, shall not be eligible for MTC compensation.
        c. The MTC shall be fixed for the term of compensation for a project.
        d. A project shall not receive the MTC on the same portion of the project that receives a credit for the DRV Component.
        e. The MTC shall be set forth in the VDER-Cred Statement.
      vii. Community Credit
        a. The Community Credit Component shall only apply to CDG projects (Rule 23) and S-SFA projects (Rule 39) that meet the further requirements specified herein.
          i. Community Credit Tranche 1 rate shall be available to a CDG project that qualified for Value Stack Compensation after July 26, 2018. The available capacity for Community Credit Tranche 1 is up to 80 MW.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)
        6. The Value Stack Components: (Cont'd)
            vii. Community Credit (Cont'd):
                a. (Cont'd)
                    ii. Community Credit Tranche 2 rate shall be available to a CDG project that qualified for Value Stack compensation and there is no available capacity for Community Credit Tranche 1. The available capacity for Community Credit Tranche 2 shall be determined by reallocating capacity from CDG projects that qualified for the MTC or Community Credit Tranche 1 and were cancelled subsequent to the creation of Community Credit Tranche 1. Reallocation of capacity to Community Credit Tranche 2 shall continue until November 1, 2020 or until the Community Credit Tranche 2 is full and cancellations have slowed such that there are no cancellations for one calendar month.
                b. The Community Credit Component will apply only to CDG project's satellites and those mass market customers who opt into the VDER Value Stack compensation per Rule 26.B.6.ii.vi.
                c. The Community Credit Component shall be calculated by multiplying: a) the sum of the CDG project's total net injections for the billing period (kWh), and b) the project's applicable Community Credit Component rate based on the project's assigned Tranche as set forth in the VDER-Cred Statement, in effect at the time of the project's Eligibility Date.
                    i. For a CDG project that includes a dispatchable high capacity factor resource, *i.e.*, a Fuel Cell, and qualified for Value Stack compensation after August 13, 2019, any applicable Community Credit shall by adjusted by a factor of 0.16. A CDG project with a dispatchable high capacity factor resource, *i.e.*, a Fuel Cell, and qualified for Value Stack compensation between July 26, 2018 and on or before August 13, 2019 shall receive an unadjusted applicable Community Credit,
                d. The project's Community Credit rate will be fixed for the first twenty-five (25) years following the project's interconnection date.
                e. The CDG Host shall not be allowed to bank any Community Credit Components related to unallocated Satellite Percentages.
                f. A project participating in the S-SFA Program, pursuant to Rule 39, may also be eligible to receive a Community Credit provided the project was allocated a Community Credit prior to March 1, 2025, during the project's application for service.
            viii. Non Mass Market Community Credit

The Non Mass Market Community Credit shall only apply to Non Mass Market satellites of CDG projects which are eligible to receive MTC for Mass Market satellites as detailed in 26.B.6.vi (Tranches 1 through 4). This credit shall begin starting with the first billing cycle for that project in which the entire billing period is after July 31, 2020. The Non Mass Market Community Credit shall not apply to excess generation banked prior to July 31, 2020.

- i. The project's Non Mass Market Community Credit rate will be fixed for the first twenty-five (25) years following the project's interconnection date.
- ii. Non Mass Market Community Credit Component rate as set forth in the VDER-Cred Statement, in effect at the time of the project's Eligibility Date.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER"): (Cont'd)
    B. Value Stack: (Cont'd)
    7. Value Stack Billing
        i. In a billing period, the sum of the credits as calculated pursuant to Section 4, shall be used to determine the customer's total credit for the month.
        ii. For each hour, the customer's usage and its generation are netted within the hour.
        iii. Where a customer-generator consumption has exceeded the Facility's generation export within an hour, the customer-generator shall be billed at the rates specified in the customer's otherwise applicable Service Classification, plus the Customer Benefit Contribution ("CBC") Charge if applicable, as described below in Special Provision 1 of Rule 26.C.
            1. A Mass-Market Customer that is interconnected on or after January 1, 2022, shall be subject to the applicable Customer Benefit Contribution ("CBC") Charge.
            2. If a customer selects Standby Service, the Company shall calculate the bill for consumption in accordance with the requirements set forth in the Standby Service Classification and will not be subject to the Customer Benefit Contribution ("CBC") Charge.
        iv. Where generation export has exceeded the customer-generator's consumption within an hour, the Value Stack Compensation credit shall be calculated by multiplying the excess generation by the applicable Value Stack components to determine the total credit.
            1. If the Company is unable to obtain an actual meter read for the Facility, the Company shall not be required to estimate Excess Generation output for determining credits.
            2. The credit shall be applied to the current utility bill for any outstanding delivery (and supply, if applicable) charges as described below. If the current month's Value Stack credit plus any prior period Value Stack Credit exceeds the current bill, the remaining credit will be handled as follows:
                a. Mass Market Customers and Large On-Site Customers
                    1. The credit will be carried forward to the succeeding billing period.
                b. Remote Crediting Customers
                    1. The credit applied to each account (*i.e.*, Host Account and Satellite Account) shall not exceed the current electric charges. Any remaining unused credits for that account will be banked and carried over on the account for its next billing period.
                    2. Banked credits remaining on the Remote Crediting Host account at the end of the billing period will be available to offset the Remote Crediting Host's electric charges on its next bill, or for future host bank disbursement to participating satellite accounts according to instructions provided to the Company in Rule 35.B.4.c.iv.
                    3. Satellite Account
                        a. If a Remote Crediting Satellite participates in multiple Remote Crediting projects, the Value Stack credit applied to the Satellite account's current electric charges will be determined on a prorata basis based on each Remote Crediting Host's total allocation to the Satellite in the month, inclusive of Host bank allocation, applied to the Satellite's current electric charges.
                        b. If a Remote Crediting Satellite is a customer-generator, any on-site generation credits will be applied to the satellite's bill before applying any credits from the Remote Crediting project.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER"): (Cont'd)
    B. Value Stack: (Cont'd)
    7. Value Stack Billing (Cont'd)
        iv. (Cont'd)

c. Community DG
    1. For CDG accounts, the credit shall be applied to electric charges on the CDG Satellite Account(s) based on the percentage allocation process set forth in Rule 23.
    2. In each billing period, any unallocated kWh credits or kWh credits that have been designated to remain on a CDG Host Account shall be converted to a monetary value based on the sum of the Value Stack credit components as described this Rule; however, the Market Transition Credit is not applicable for the conversion of these credits (the "Banked Monetary Credit").
    3. The Banked Monetary Credits shall be carried forward on the CDG Host Account to the succeeding bill period until the earlier of:
        a. CDG Host notifies the Company of the subscribers to receive the Banked Monetary Credits and the amount of credits to be allocated to the subscriber, regardless of the allocation specified in Rule 23.3; or
        b. The two-year grace period has expired.
    4. If a monetary credit remains on any CDG Satellite Account, the remaining credit will be carried forward on that CDG Satellite Account to the succeeding billing period.
    5. After a final bill is rendered on a CDG Host Account, any remaining credit shall not be cashed out, refunded, or transferred. CDG Satellite Accounts shall no longer receive credits after the final bill is rendered on the account of its CDG Host. If a credit remains on a CDG Satellite Account after its final bill is rendered, such credit shall be forfeited as set forth in Rule 23.8.d.

d. Statewide Solar For All ("S-SFA")
    1. For customer-generators participating in the S-SFA Program pursuant to Rule 39 of this Schedule, the credit shall be allocated based on the customer-generator's established S-SFA Project Compensation Level.
    2. The S-SFA Project Compensation Level shall determine the percentage of the customer-generator's excess generation credits that will be allocated to the:
        a. Credit Pool;
        b. Paid to the customer-generator; and
        c. Utility Administration Fee.
    3. S-SFA Program details are set forth in Rule 39 of this Schedule.

e. Renewable Energy Access and Community Help ("REACH") Program
    1. For eligible projects participating in the REACH Program pursuant to Rule 40 of this Schedule, the credit shall be allocated based on the project's established Compensation Level.
    2. The Compensation Level shall determine the percentage of the project's excess generation credits that will be allocated to the:
        a. Credit Pool;
        b. Paid to the New York Power Authority or their assigned designee; and
        c. Utility Administration Fee.
    3. REACH Program details are set forth in Rule 40 of this Schedule.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)

        7. Value Stack Billing (Cont'd)
            v. Storage
                a. A customer participating in the Value Stack provision with stand-alone storage that is sized to exceed 115% of their peak consumption load and taking supply service with the Company, shall be charged for consumption at the Mandatory Hourly Price (MHP) rate.
                    i. A customer with stand-alone storage that is sized not to exceed 115% of the customer's peak consumption load shall have the option to be charged at the Hourly Pricing rate.
                b. A customer with stand-alone storage, participating in the Value Stack provision and taking service with an ESCO; the electricity supply charge shall be equal to the sum of the hourly metered usage multiplied by the NYISO Day-Ahead Market.
                c. For customers taking service under this Rule who pair energy storage systems with eligible electric generating equipment ("Hybrid Facility"), the Company shall calculate the Capacity Component Credit, the Environmental Component Credit, and the Market Transition Credit ("MTC") pursuant to the rules set forth below. All other Value Stack components, including Energy Component Credit, DRV Component Credit, and LSRV Component Credit, shall be calculated as specified in Rule 26.B.6. Consistent with Rule 26.B.6, Environmental Component Credit shall only be provided where the electric generating equipment is eligible to receive Tier 1 RECs, MTC shall only be provided for eligible customers and consistent with the MTC rate applicable to the customer, and Capacity Component shall be calculated based on Alternative One, Alternative Two, or Alternative Three based on customer election.
                d. Customers operating Hybrid Facilities shall have the opportunity to elect one of the four compensation methodologies described below in d.i, d.ii, d.iii, or d.iv. Customers shall make this election at the same time they select a capacity compensation methodology in accordance with26.B.6.ii.vi.. The default option, if no other election is made by the customer, is compensation methodology d.iv. below.

                Customers operating Hybrid Facilities shall have a one-time option to change their initial election of d.i or d.ii to election of d.iii. This one-time election may be made at any time following the initial election but shall not become effective until such time that any required metering or telecommunications is installed.
                    i. Storage Exclusively Charged from Eligible Generator – For customers operating Hybrid Facilities who are able to demonstrate the energy storage system charges exclusively from the qualified electric generating equipment, the Value Stack Capacity Alternative One or Alternative Two Component Credit (if elected), Environmental Component Credit, and MTC shall be based on net hourly injections to the Company's electric system as measured at the Company's meter located at the point of common coupling ("PCC") and calculated as described in Rule 26.B.6. Value Stack Capacity Component Alternative Three Credit (if elected) shall be calculated as specified in Rule 26.B.6. Customers shall be responsible for any work required to accommodate the appropriate controls and/or multiple meter configuration. The utility may require two Company time synchronized revenue-grade meters if the energy storage system and electric generating equipment share a common inverter or three Company time-synchronized revenue-grade meters if the energy storage system and electric generating equipment each have a separate inverter.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)

        7. Value Stack Billing (Cont'd)
            v. Storage (Cont'd)
                ii. Storage Controls Configuration – For customers operating Hybrid Facilities who install appropriate controls to ensure that net hourly injections are only made with the energy storage not in a charging or discharging mode from the electric grid, the Value Stack Capacity Component Alternative One or Alternative Two Credit (if elected), Environmental Component Credit, and MTC shall be based on net hourly injections to the Company's system and calculated as described in Rule 26.B.6. Value Stack Capacity Component Alternative Three Credit (if elected) shall be calculated as specified in Rule 26.B.6. Customers shall be responsible for any work required to accommodate the appropriate controls and/or multiple meter configuration. This controls demonstration may require separate Company revenue grade interval meter(s) and appropriate telemetry on the AC side of the applicable inverter(s) and explicit Company acceptance.
                iii. Storage Import Netting Configuration - For customers operating Hybrid Facilities with a separate Company revenue grade interval meter and appropriate telemetry on the AC side of the inverter of the Hybrid Facility and whose storage configuration does not meet the requirements of d.i. or d.ii. above, the Value Stack Capacity Component Alternative One Credit (if elected), Environmental Component Credit, and MTC shall be determined by reducing the net hourly injections, as measured at the Company's meter located at the Customer's PCC with the Company's system, by the monthly consumption of energy recorded on the Company's separate Hybrid Facility meter. Value Stack Capacity Component Alternative Two Credit (if elected) shall be determined by reducing the net hourly injections during applicable hours, as measured at the Company's meter located at the Customer's PCC with the Company's system, by the monthly consumption of energy recorded on the Company's separate Hybrid Facility meter. Value Stack Capacity Component Alternative Three Credit (if elected) shall be calculated as specified in Rule 26.B.6.
                iv. Storage Default Configuration - For all other Customers with energy storage paired with electric generating equipment, the Value Stack Capacity Component Alternative One or Alternative Two Credit (if elected), Environmental Component Credit, and MTC shall be based on netting of all metered consumption and injections at the PCC over the applicable billing period. Value Stack Capacity Component Alternative Three Credit (if elected) shall be calculated as specified in Rule 26.B.6.
                v. The Customer is responsible for any costs associated with additional metering requirements and telemetry as described in Rule 3.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    B. Value Stack: (Cont'd)

8. Account Closure
    a. The Company shall require an actual meter reading to close an Account pursuant to this Rule.
    b. The Company shall close an account on the earlier of: (a) the first cycle date on which a reading is taken following the requested turn off date, or (b) the date of a special reading, which a Customer may request at the charge specified in General Information Rule 11.7.(c).
    c. After the customer's final bill is rendered, any remaining credit shall not be transferred, except for a CDG Satellite Account. Such credit shall be returned to the CDG Host Account.

9. Term

   The Term of Service for a Facility pursuant to the General Information Rule, Value Stack, shall be 25 years from the Facility's in-service date.

10. One-Time Voluntary Switch Between Community Distributed Generation and Remote Crediting

    A customer shall have the option to make a one-time voluntary switch from Remote Crediting to CDG (including Net Crediting), or from CDG (including Net Crediting) to Remote Crediting. The procedure to switch is detailed in the CDG VDER Procedural Requirements manual posted on the Company's website.
    a. The project shall remain under the Value Stack compensation mechanism.
    b. If a customer chooses to make a one-time voluntary switch, the component rates that were established on the customers eligibility date shall not change and all project elections shall carry forward.
    c. The compensation term shall be that of the program that a customer is switching into and begins on the project's original interconnection date.
    d. The customer shall retain any monetary credits banked on the host account; this shall be the starting balance of the new host bank.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)

C. Special Provisions:

1. Customer Benefit Contribution ("CBC") Charge
   a. Applicable to a non-demand customer that installs on-site solar generating equipment, on-site wind generating equipment or micro-hydroelectric generating equipment as specified below:
      i. A customer that installs new electric generating equipment as defined above and is interconnected on or after January 1, 2022.
         a. The CBC shall be applied to any subsequent capacity expansions for new systems interconnected on or after January 1, 2022.
      ii. A customer that completely replaces an electric generating system as defined above that was interconnected before January 1, 2022, after the system replacement is completed.
         a. The CBC shall be applied to any subsequent capacity expansions for replaced systems.
   b. A customer shall be subject to the applicable CBC Charge for the customer's Compensation Term regardless of the customer's methodology of compensation pursuant to Rule 26.A - Phase One NEM or Rule 26.B - Value Stack.
   c. A customer that was interconnected prior to January 1, 2022, that incrementally expands the capacity of their electric generating system shall not be subject to the CBC on their original capacity or the expanded incremental capacity.
   d. Development of the CBC:
      i. A per installed kW rate for each service class is calculated to collect applicable costs of the following programs: Clean Energy Fund, Low Income Program and Energy Efficiency Program.
      ii. The per installed kW rate will be determined for each type of compensation methodology *i.e.* Phase One NEM or Value Stack.
   e. The CBC Charge will be determined on each bill by multiplying the applicable monthly CBC, set forth on the CBC Statement, by the nameplate capacity rating in kW Direct Current of the Customer's electric generating equipment. For a customer that installed energy storage technology with their electric generating equipment, the energy storage technology shall not affect the amount of kW included in the CBC Charge calculation
   f. The CBC Charge shall be updated annually.
   g. The CBC Charges shall be set forth on the Customer Benefit Contribution ("CBC") Statement which shall be filed with the Commission on not less than 15 days' notice to be effective on January 1 of each year.

GENERAL INFORMATION

26. Value of Distributed Energy Resources ("VDER") (Cont'd)
    C. Special Provisions (Cont'd):

2. Wholesale Value Stack ("WVS")
    a. A customer taking service under Rule 26.B Value Stack that elects to export to NYISO, either directly or through aggregation, must take service under WVS.
        i. In order to take service under WVS, an existing Value Stack customer must make this election by August 1st to be effective May 1st of the following year.
        ii. A customer who is not yet interconnected to the Company's distribution system that is eligible for Value Stack compensation pursuant to Rule 26.B and also elects to participate in WVS, must notify the Company at the time of the customer's Value Stack eligibility date to receive compensation under WVS at time of successful enrollment with NYISO.
    b. A customer that elects to export to NYISO, shall receive energy and capacity compensation directly from NYISO in lieu of receiving the Value Stack Energy Component, Rule 26.B.6.i, and the Value Stack Capacity Component, Rule 26.B.6.ii.
        i. A customer taking service under WVS shall be eligible for the following Value Stack Components, as applicable: Environmental Component, Demand Reduction Value ("DRV") Component, Locational System Relief Value ("LSRV") Component, Market Transition Credit ("MTC"), Community Credit, and the Non-Mass Market Community Credit (Rule 26.B.6.iii through Rule 26.B.6.viii).
    c. A WVS customer must adhere to the metering requirements set forth in Rule 26.B.1.f.
    d. A WVS customer must also take service under the Company's Wholesale Distribution Service ("WDS") tariff on file with the Federal Energy Regulatory Commission.
    e. A WVS customer returning to Rule 26.B Value Stack shall only be eligible for the Value Stack Capacity Component for which they were previously compensated under. In addition, such customer shall retain the same Value Stack Eligibility Date as well as any Value Stack component rates locked in at the time of previous Value Stack eligibility.
    f. A WVS customer is ineligible to participate in the Statewide Solar For All Program (Rule 39) or the Renewable Energy Access and Community Help Program (Rule 40).

27. Reserved for Future Use

GENERAL INFORMATION

28. Remote Net Metering
A customer may participate in Remote Net Metering ("RNM") as provided herein.

A. Definitions

Host Account: The customer meter where the generating equipment is located and interconnected with the Company's distribution system, and is eligible for net metering pursuant to this Rule.

Satellite Accounts: Additional meters designated by the Host Account, with the same name on the account, for the application of excess net metering credits.

Net-Metered Generation Facility: A generation facility eligible for net metering in conformance with PSL 66-j or 66- l, limited in size consistent with those statutes, located behind the meter of the Host Account and attached to a load served under one of the Company's service classifications.

Excess Generation: the electricity (kWh) supplied by the customer to the Company during the billing period exceeds the electricity (kWh) supplied by the Company to the customer. For customers billed on time-differentiated rates (TOU meter), e.g., On-Peak/Off-Peak, the excess is calculated and maintained for each peak.

B. Customer Requirements and Eligibility

1. To qualify for RNM, the Net-Metered Generation Facility must be:
   a. Residential customer who own or operate a farm operation (as defined by Agriculture and Markets Law §301(11)), and locate solar photovoltaic equipment on property the customer owns or leases as defined in Rule 13.D.1; or
   b. A Non-Residential Solar Electric Net-Metered Generation Facility, as defined in Rule 13.D.1; or
   c. A Farm Waste Net-Metered Generation Facility, as defined in Rule 13.D.1; or
   d. A Micro-Hydroelectric Net-Metered Generation Facility, defined as one who owns or operates micro-hydroelectric generating equipment with a rated capacity conforming with Rule 13.D.1 and used at a "farm operation" as defined by Agriculture and Markets Law §301(11); or
   e. A Non-Residential Micro-Hydroelectric Net-Metered Generation Facility, as defined in Rule 13.D.1; or
   f. A Residential Fuel Cell Net-Metered Generation Facility as defined in Rule 13.D.1, who operate a farm operation as defined by Agriculture and Markets Law §301(11), or a Non-Residential Fuel Cell Net-Metered Generation Facility, as defined by Rule 13.D.1; or
   g. A Non-Residential Farm Waste Net-Metered Generation Facility as defined in Rule 13.D.1.
   h. A Residential or Non-Residential customer who owns or operates stand-alone storage, subject to the requirements described in Rule 26.B.

2. A Net-Metered Generation Facility, who qualifies per the above, may designate all or a portion of their excess net metering credits generated by such equipment, after application to the Host Account, to Satellite Accounts at any property owned or leased by such customer within the same load zone as determined by the Locational Based Market Price. The Company reserves the right to obtain proof that all accounts are held by the qualifying customer.

3. The aggregated rated capacity of generating equipment of Host Account(s) designated to serve a Satellite Account plus the rated capacity of net-metered generating equipment on the Satellite Account, if any, cannot exceed 2,000 kW, as applicable to RNM pursuant to General Information Rules 13.D.1, or 26.A, and cannot exceed 5,000 kW, as applicable to RNM pursuant to General Information Rule 26.B.

GENERAL INFORMATION

28. Remote Net Metering (Cont'd)

C. Host Account

1. A customer may designate more than one Host Account and shall provide an application for each Host Account.
2. The Host Accounts must be held by the same customer and have an identical billing name, on property owned or leased by such customer.
3. A Host Account cannot be a Satellite Account.
4. The Host Account must designate their satellite accounts and the portion of their net metering credits designated to these Satellite Accounts when submitting their initial remote net metering application.
5. After the initial application, the Host Account may designate additional Satellite Accounts or delete existing Satellite Accounts as specified in Section E, Enrollment and Change Period.
6. Grandfathering Requirements

a. By June 1, 2015, if any of the following criteria were met, such project shall be allowed to retain monetary crediting pursuant to Section F:

i. Projects that have been interconnected; or
ii. Projects for which developers have submitted a completed preliminary interconnection application to the Company; or
iii. Projects that have completed applications for grants through Program Opportunity Notices ("PONs") 2112, 2439, 2589, 2860, and 2956 conducted by the New York State Energy and Research Development Authority ('NYSERDA"); or
iv. Projects that have completed applications for grants in NYSERDA's NY-Sun MW Block Program for projects sized more than 200 kW; or
v. Projects that a State, municipal, district, or local governmental entity has solicited through a Request for Proposals or a Request for Information issued in conformance with applicable law; or
vi. A project must enter service by the date specified in the NYSERDA PONs or NY-Sun MW Block Program for projects sized at more than 200 kW, or another governmental entity process, as that date may be extended by the relevant governmental entity, or by December 31, 2017, if no date is specified by a governmental entity

b. If a project that meets the criteria in Section 6.a.iii or 6.a.iv. above is unable to meet the in-service date of December 1, 2017, and meets the following criteria and conditions, the project shall be allowed to retain monetary crediting as described in Section F., as long as the following four criteria are met:

i. The project developer has provided payment, prior to March 1, 2016, for a Coordinated Electric System Interconnection Review (CESIR) study;
ii The project developer has demonstrated that, upon receipt of the CESIR study results, the estimated construction schedule indicates a final authorization to interconnect on or after July 1, 2017;
iii. The project developer has made payment, of the full or at least the first installment amount for the estimated utility interconnection costs necessary to support the project, by January 31, 2017; and,
iv. The project developer has, by November 30, 2017, submitted an affidavit from the engineer of record for the project on the end-use customer's side of interconnection point has been physically constructed and that the only remaining requirements to interconnect the equipment depend upon utility, such as remaining utility construction and/or authorization to interconnect.

GENERAL INFORMATION

28. Remote Net Metering (Cont'd)

C. Host Account (Cont'd)

c. If the criteria and conditions as set forth in this Section are met, the monetary credit will remain in effect for a term of twenty-five (25) years from the later of the date of April 17, 2015 (issue date of Commission's Order in Case 14-E-0151 and 14-E-0422) or the project in-service date. An extension of this period may be obtained upon a showing that the contractual arrangement for financing a particular project cannot be accomplished within a 25 year period, and a longer period is necessary.

D. Satellite Accounts

1. Must be held by the same customer and have an identical billing name, on property owned or leased by such customer.
2. The Company reserves the right to investigate/obtain proof that all designated accounts are held by the customer.
3. A Satellite Account may have more than one Host Account. The name plate rating of the Net Metered Generation Facility(ies) designated as Host Accounts to be applied to a Satellite Account shall not exceed 2 MW in aggregate, including the name plate rating of a Net Metered Generation Facility located at the Satellite Account.

E. Enrollment and Change Period

After the customer's initial application, the enrollment and change period is from January 1 through January 31. Any changes shall be effective with the initial Host Account billing after March 1. Remote Net Metering customers may submit a change request form annually during the change period to designate additional Satellite Accounts or delete existing active Satellite Accounts. The customer may also change the portion (percentage) of excess to remain at the Host Account once per year.

F. Calculation and Application of Net Metering Credits

1. In the event that the amount of electricity supplied by the Company during the billing period exceeds the amount of electricity provided by the Host Account's Net Metered Generation Facility to the Company during the same billing period, the Company shall charge the Host Account at the rates provided in the otherwise applicable service classification of the Host Account for the net amount of electricity supplied by the Company.

2. If more than one Host Account is designated by the customer and there is excess generation from more than one Host Account, the Company shall apply credits from the Host Accounts to the Satellite Accounts in the following order:
    a. Grandfathered or Demand-billed Host Accounts participating in Farm Waste (Facility Located and Used for Farm Operations) or Farm Wind Electric Service Options;
    b. Grandfathered or Demand-billed Host Accounts participating in Non-Residential Solar, Non-Residential Wind, or Micro-Hydroelectric Service Options;
    c. Host Account participating in Fuel Cell or Farm Waste (Facility Located and Used at Premises) Service Options;
    d. Any other non-demand-billed Host Accounts.

GENERAL INFORMATION

28. Remote Net Metering (Cont'd)

F. Calculation and Application of Net Metering Credits (Cont'd)

3. Application of Monetary Credits:
    a. The credit applied to each Host Account shall not exceed the current electric delivery charges, and if applicable, Company supply charges.
    b. Except for a Host Account with Fuel Cell and non-farm based Farm Waste generators, a Host Account that is entitled to retain monetary crediting, may opt out to select volumetric crediting if they submit a statement in writing to the Company. The Company will acknowledge the request for volumetric crediting to the Host Account. When a preference for volumetric crediting is not stated, the Company will assume that monetary crediting adheres if there is an entitlement to Grandfathering in accordance with this Rule.

    i. Host Account:
        a. In a month where the Host Account has Excess Generation, the Excess Generation shall be converted to the equivalent monetary value at the per kWh rate applicable to the Host Account's service classification and shall first be applied to any outstanding charges on the Host Account's current electric bill, except for customers with Fuel Cell generation facilities and non-farm based Farm Waste generators.
        b. Customers with Fuel Cell generation facilities and non-farm based Farm Waste generators: In a month where the Host Account has Excess Generation, the Excess Generation shall be converted to the equivalent monetary value at the Company's Service Classification No.5 Buy Back Service Energy only rate. The remote net metering credit shall first be applied to any outstanding charges on the Host Account's current electric bill

    ii. Satellite Accounts:
        a. Any remaining monetary credit from the Host shall be allocated to each Satellite Account in accordance with the Host Account's designation on the application form , including any changes identified in the Change Period.
        b. The portion designated for the Satellite Accounts shall be applied to the Satellite Account bill as each subsequent Satellite Account bill is calculated.
        c. If a monetary credit remains after applying credits to all designated Satellite Accounts, the credit shall be carried forward on the Host Account and the allocation process between Host and Satellite Accounts shall repeat until the value of the excess credit is zero, or until all associated accounts are finaled. In the case of two Satellite Accounts billed on the same day, the excess credit shall be applied to the highest usage account first.
        d. The credit applied to each Satellite Account shall not exceed the delivery charges, and if applicable, Company supply charges.

4. Application of Volumetric kWh Credits:
    a. Host Account:
        i. In a month where the Host Account has Excess Generation, the Excess Generation shall be converted to the equivalent monetary value at the per kWh rate applicable to the Host Account's service classification and shall first be applied to any outstanding charges on the Host Account's current electric bill, except for customers with Fuel Cell generation facilities and non-farm based Farm Waste Generators.
        ii. Fuel Cell generation facilities and non-farm based Farm Waste Generators: In a month where the Host Account has Excess Generation, the Excess Generation shall be converted to the equivalent monetary value at the Company's Service Classification No.5 Buy Back Service Energy only rate. The remote net metering credit shall first be applied to any outstanding charges on the Host Account's current electric bill

GENERAL INFORMATION

28. Remote Net Metering (Cont'd)

F. Calculation and Application of Net Metering Credits (Cont'd)

4. Application of Volumetric kWh Credits (Cont'd):

   b. Satellite Accounts:
      i. As each Satellite Account is billed, Excess Generation designated to the Satellite Account is converted to a monetary credit and applied to the per kWh charges on the Satellite Account.
      ii. Monetary credits are calculated using the per kWh rate for the Service Classification applicable to the Satellite Account. If a credit remains after applying to the Satellite Account, the credit is converted back to kWh based on the per kWh rate for the Service Classification applicable to the Satellite Account and the kWh are transferred to the Host Account. This process between Host and Satellite Accounts shall repeat until the value of the excess credit is zero, or until all the Satellite Accounts have been billed.
      iii. Any remaining kWh credits shall be carried forward on the Host Account to the following month. In the case of two Satellite Accounts billed on the same day, the excess credit shall be applied to the highest usage account first.
      iv. The credit applied to each Satellite Account shall not exceed the current per kWh electric delivery charges, and if applicable, Company supply charges.

5. Annual reconciliation of remaining credits:
   A Farm Waste Electric Generating customer shall have an annual reconciliation of remaining credits. Any remaining monetary credits shall be cashed out at avoided cost. For Non-Hourly Pricing customers, the cash-out payment shall be equal to the product of the kWh excess multiplied by the average avoided cost for the energy for the billing period in which the excess occurred. For Hourly Pricing customers, the payment shall be for the remaining portion of the excess credit priced at avoided cost.

G. Host Account Closure

See Rule 13.F, Distributed Energy Resources, for Account Closures. Any remaining excess credits shall not be cashed out or transferred.

Upon the Company's determination that the customer has taken service under this Section while in violation of the conditions of service set forth in this Schedule, the customer shall forfeit any positive balance accrued during the annual period in which the violation occurred.

29. Reserved for Future Use

GENERAL INFORMATION

30. Energy Storage Deployment Cost Recovery

A. The Company shall collect costs related to the contracts for procuring qualified energy storage assets in accordance with the Company's Implementation Plan filed with the Public Service Commission in Case 18-E-0130 ("Energy Storage Costs"), over the term of the energy storage procurement contract.

B. Any payments or credits received by the Company realized from the contracts for the energy storage assets shall reduce the Energy Storage Costs; however, if the net annual wholesale market revenues exceed annual costs, the excess revenues shall be shared on a 70/30 basis between delivery customers and shareholders.

   i. Annual wholesale market revenues (avoided wholesale electric market costs or direct revenue from the NYISO) ("ES Revenues") from the energy storage asset, that are greater than the ES Costs on an annual basis will be "Annual Net ES Revenues."

C. The costs shall be collected from all customers taking electric delivery service and allocated to each service class based on the following allocators:

   i. coincident peak demand for the transmission portion (if any) of the deferred traditional project; and
   ii. non-coincident peak demand allocator for the sub-transmission and distribution portions of the deferred traditional project.

   Recovery shall be on a per kWh basis for non-demand customers; on a per kW basis for demand-billed customers; and on a per As-Used basis for Standby customers.

D. Once allocated to each applicable service class, the costs shall be collected for the energy storage asset through the Transition Charge. A statement setting forth the energy storage cost recovery rates shall be filed with the Commission on not less than 30 days' notice. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

31. Term and Auto- Dynamic Load Management Programs

A. Programs

1. Term Dynamic Load Management Program (“Term DLM” Program)
A customer that qualifies to participate in the Term DLM Program shall provide load relief of at least 50 kW during the Capability period and as further required herein. The Term DLM Program shall be available throughout the Company’s service territory.

2. Auto-Dynamic Load Management Program (“Auto DLM” Program)
A customer that qualifies to participate in the Auto DLM Program shall provide load relief on not less than 10 minutes advance notice for the following conditions: (1) as a contingency program to prevent or mitigate critical situations on the utility’s electric grid; or (2) for peak shaving purposes using the same activation criteria as for Term-DLM. The Auto DLM Program shall be offered in locations as specified by the Company.

B. Definitions

Applicable to Both Programs

“Advisory” refers to the Company’s notice that the Company’s day-ahead forecasted load level reaches a Company specified percent of its forecasted summer system-wide peak. Day-ahead and summer peak forecast information for the system will be posted to the Company’s website.

"Aggregation” means either a Sub-aggregation or all customers represented by an Aggregator within a Network if there are no Sub-aggregations for that Aggregator within that Network.

"Aggregator" refers to a party other than the Company that represents and aggregates the load of Customers who collectively have a Load Relief potential of 50 kW or greater under Term- or Auto-DLM and that is responsible for the actions of the Customers it represents, including performance and, as applicable, repayments to the Company.

“Capability Period” The period during which the Company can request Load Relief. The Capability Period from May 1 through September 30.

“CBL” Customer baseline load as calculated under the Company’s Customer Baseline Load methodology, using either the weather-sensitive adjustment option (the “weather adjusted CBL”) or the average-day CBL. The Customer Baseline Load methodology shall be described in the Company’s baseline operating procedure, which shall be published on the Company’s website.

“CBL Verification Methodology” The methodology used by the Company to verify the actual Load Relief provided (kW and kWh) during each hour of each designated Load Relief Period and Test.

Actual load levels are compared to the customer baseline loads to verify whether the Direct Participant or Aggregator provided the kW of contracted Load Relief; provided, however, that the Company may estimate the data pursuant to the Company's operating procedure if data is not available for all intervals. When the weather-adjusted CBL methodology is used and the calculated weather adjustment falls outside of the Company defined ranges (i.e., the Company deems the weather to be atypical on the day of a Load Relief Period or Test when compared to the baseline period), the Company may review and revise a participant’s baseline based on the Customer’s historical load data. When the weather-adjusted CBL methodology is used, the Company, at its own discretion, may select alternate hours for the adjustment period to calculate the weather adjustment in order to accurately reflect the customer’s typical usage.

GENERAL INFORMATION

31. Term and Auto- Dynamic Load Management Programs

B. Definitions (Cont'd)

Applicable to Both Programs (Cont'd)

"Company Designated Area" An electrically defined area determined by the Company to be approaching system capacity limits during peak periods.

"Direct Participant" refers to a customer who enrolls under Term- or Auto-DLM directly with the Company for a single account and agrees to provide at least 50 kW of Load Relief.

"Electric Generating Equipment" refers to: (a) electric generating equipment that is served under Service Classification No. 14 or Wholesale Distribution Service and used to provide Load Relief under this Program; or (b) emergency electric generating equipment that is interconnected and operated in compliance with rules governing Emergency Generating Facilities used for self supply and used to provide Load Relief under this Program.

"Load Relief": Power (kW) and energy (kWh): (a) ordinarily delivered by the Company that is displaced by use of Electric Generating Equipment and/or reduced by the Direct Participant or Aggregator at the Customer's premises; or (b) produced by use of Electric Generating Equipment by a customer taking service pursuant to Service Classification No. 5 or Wholesale Distribution Service and delivered by that Customer to the Company's distribution or transmission system during a Load Relief Period.

"Load Relief Period" refers to the hours for which the Company requests Load Relief during: (a) a Term-DLM Event, which can also include Auto-DLM participants; or (b) an Auto-DLM Event, provided, however, that Load Relief shall not be required under Auto-DLM between the hours of 12:00 a.m. and 6:00 a.m.

Portfolio Quantity: For each Aggregation of an Aggregator or Direct Participant, the amount of Load Relief measured in kW that the Aggregator or Direct Participant has agreed to provide based on the Program Agreement and any Early Exit fees paid in association with that Aggregation.

"Program Agreement" refers to the specific terms and conditions that apply to Aggregators and Direct Participants based on signed contracts associated with their Vintage Year.

"Sub-aggregation" means a subset of Customers represented by an Aggregator. An Aggregator may create Sub-Aggregations as specified in the Program Agreement for a given year.

"Test Event" refers to the Company's request of either Term- or Auto-DLM for Direct Participants and Aggregators to provide Load Relief in order to test participants' response to a request for Load Relief. The duration of a Test Event is one hour for both Term- and Auto-DLM. If a Test Event is called under Term-DLM, Load Relief shall be requested within the four-hour span of Contracted Hours. If called under Auto-DLM, Load Relief shall be requested at a time determined solely at the Company's discretion but not between the hours of 12:00 a.m. and 6:00 a.m.

"Vintage Year" refers to the first Capability Period an Aggregator or Direct Participant is contractually obligated to participation in.

GENERAL INFORMATION

31. Term and Auto- Dynamic Load Management Programs

B. Definitions (Cont'd)

Definitions applicable to Term-DLM only

"Contracted Hours" refers to the four-hour period within a weekday, Monday through Friday during the Capability Period, excluding federal holidays, during which the Direct Participant or Aggregator contracts to provide Load Relief in a Company Designated Area whenever the Company designates a Term-DLM Event. The Contracted Hours are established by the Company for each Company Designated Area based on individual Company Designated Area needs. The Contracted Hours for any S.C. No. 5 customer who exports power to the Company shall be the Contracted Hours established by the Company unless the Company assigns an alternate four-hour period.

"Renewable Generation" means behind-the-meter electric generating equipment that is not fossil-fueled and has no emissions associated with it.

C. Application and Terms of Service

1. A customer that takes service under one of the following Service Classification Nos. 1, 2, 3, 4, 5, 7, 8, 9, 10, 11 or 14, whether receiving electricity supply from the Company or an ESCO, including any NYPA Customer ("Direct Participant"), and to any Aggregator that meets the requirements of these Programs.
2. A customer taking service under this Rule shall enter into a Program Agreement with the Company. The ability to complete these Program Agreements is awarded based on an open, pay-as-bid, or a fixed, published price, Request for Proposal ("RFP") process which considers the price per kW offered, the quantity of proposed load relief, the network the load relief shall be provided in, and the program the applicant is applying for. All bids shall be for single Aggregations (including sub-Aggregations) and shall be considered at the Aggregation level
3. A Direct Participant must contract to provide at least 50 kW of Load Relief. An Aggregator must contract to provide at least 50 kW of Load Relief.
4. Load Relief of an Aggregator shall be measured on a portfolio basis by Aggregation.
5. A single CBL Verification Methodology shall be used for each Customer account to assess both energy (kWh) and demand (kW) Load Relief.
6. A Direct Participant or Aggregator may change the CBL Verification Methodology or kW of pledged Load Relief for the upcoming Capability Period provided the request is received prior to commencing participation for that Capability Period.

GENERAL INFORMATION

31. Term and Auto- Dynamic Load Management Programs

C. Application and Terms of Service (Cont'd)

7. If a Direct Participant or Aggregator requests to operate Electric Generating Equipment for Load Relief purposes under this Program, the application must state generator information, including the unit's serial number, nameplate rating, manufacturer, date of manufacture, fuel type or energy source, the kW enrolled using this equipment, and identification as to whether the unit incorporates three-way catalyst emission controls (natural gas-fired rich burn), a natural gas lean-burn engine of model year vintage 2000 or newer, or whether it has a NOx emission level of no more than 2.96 lb/MWh. If the generating equipment has a NOx emission level of no more than 2.96 lb/MWh, but is not natural gas-fired rich burn generating equipment that incorporates three-way catalyst emission controls, a natural gas lean-burn engine of model year vintage 2000 or newer, written certification by a professional engineer must be attached to the application attesting to the accuracy of all generation-related information contained in the application, including the NOx emission level.
8. A customer that participates in Net Energy Metering, as identified in in PSL Section 66-j or PSL Section 66-l, or Phase One NEM (as defined in Rule 26.A) is not eligible to participate in these Programs. However, a customer that is participating in Rule 26.B., Value Stack and qualifies for DRV and/or LSRV of the Value Stack compensation is permitted to participate in these Programs in lieu of receiving the DRV and/or LSRV compensation
9. A Direct Participant/Aggregator that qualifies to participate in the Term DLM Program may be eligible to simultaneously participate in the Dynamic Load Relief Program, however, the Direct Participant/Aggregator shall not participate in the Commercial System Relief Program or the Auto-Dynamic Load Management Program at the same time.
10. A Direct Participant/Aggregator that qualifies to participate in the Auto DLM Program shall not be eligible to participate in the Dynamic Load Relief Program, or the Commercial System Relief Program or the Term DLM Program.
11. A Direct Participant/Aggregator exporting to the NYISO through one of its wholesale DER participation model programs may also participate in the Term and Auto- Dynamic Load Management Programs.
12. Within these geographic areas, no limit or cap shall be placed on the following: natural gas-fired rich burn Electric Generating Equipment that incorporates three-way catalyst emission controls; natural gas lean-burn Electric Generating Equipment with an engine of model year vintage 2000 or newer; or Electric Generating Equipment that has a NOx emissions level of no more than 2.96 lb/MWh. 7. If a Direct Participant or Aggregator requests to operate Electric Generating Equipment for Load Relief purposes under this Program, the application must state generator information, including the unit's serial number, nameplate rating, manufacturer, date of manufacture, fuel type or energy source, the kW enrolled using this equipment, and identification as to whether the unit incorporates three-way catalyst emission controls (natural gas-fired rich burn), a natural gas lean-burn engine of model year vintage 2000 or newer, or whether it has a NOx emission level of no more than 2.96 lb/MWh. If the generating equipment has a NOx emission level of no more than 2.96 lb/MWh, but is not natural gas-fired rich burn generating equipment that incorporates three-way catalyst emission controls, a natural gas lean-burn engine of model year vintage 2000 or newer, or a diesel-fired engine of model year vintage 2000 or newer, written certification by a professional engineer must be attached to the application attesting to the accuracy of all generation-related information contained in the application, including the NOx emission level.

D. Event Notification by the Company

1. Under Term-DLM:
   a. The Company shall call a Term-DLM Event or Test Event on not less than two hours' advanced notice.
   b. A Term-DLM Event or Test Event shall not be called unless an Advisory was issued at lease at least 21 hours in advance.
2. Under Auto-DLM:
   The Company shall call an Auto-DLM Event or Test Event on not less than ten minutes' advanced notice.

GENERAL INFORMATION

31. Term and Auto- Dynamic Load Management Programs

F. Early Exit Fee

Aggregators and Direct Participants shall have the right to terminate their obligations under their Program Agreement prior to the first Capability Period, before a Company specified deadline, by paying a fee equal to ten percent of the product of the remaining length of the contractual obligation in years, the Aggregator or Direct Participant's applicable reservation rate and the kW of Portfolio Quantity. At its discretion, the Company can offer additional opportunities to exercise such early exit rights or require payment of the Early Exit Fee based on a failure to meet minimum performance standards. These shall be specified in Program Agreements.

G. Cost Recovery

1. The Company shall collect the costs of these Programs from all customers pursuant to Rule 12.B.1, Transition Charge (Non-Bypassable Charge ["NBC"]). The collection amount shall be allocated to each service classification based upon the Company's most recent transmission plant allocator.
2. The costs shall be collected from non-demand billed customers on a per kWh basis and from demand billed customers on a per kW.
3. The costs shall be tracked separately and reconciled with revenues collected for the Programs on an annual basis, inclusive of interest at the effective New York State Public Service Commission's published customer deposit rate applicable to investor owned utilities.
4. A DLM Statement setting forth the cost values included in the Transition Charge (Non-Bypassable Charge ["NBC"]) by service classification shall be updated annually and filed on not less than one days' notice. Such statement can be found at the end of this Schedule (P.S.C. No. 19 – Electricity).

H. Participation in Non-Wires Alternative Solutions

1. A Direct Participant or Aggregator shall provide the contracted load relief for the duration of the contract term as specified in solicitation.
2. If the Direct Participant or Aggregator is able to provide additional load relief that is incremental to the contracted kW amount, the Direct Participant or Aggregator may provide such service to a Non-Wires Alternative Solution, if selected.

I. Metering

1. Participation under these Programs require that each participant's entire service be measured by interval metering with telecommunications capability used by the Company for monthly billing. If an Aggregator takes service under these Programs, all customers of the Aggregator must meet the metering and telecommunications requirements specified herein.

2. If, at the time of application for service under one of these Programs, the Company does not bill the participant monthly using interval metering, the Direct Participant shall arrange for the furnishing and installation of interval metering with telecommunications capability to be used for billing and arrange for telecommunications service, at the participant's expense.

3. The Company shall visit the premises at the request of the customer to investigate a disruption of normal communications between the phone line or wireless communication and the meter, or operation of external pulses from the meter to the customer's energy management equipment. The Company shall charge for its visit based upon the cost to the Company.

GENERAL INFORMATION

32. Non-Wire Alternatives ("NWA")

A. The Company may implement a NWA as an alternative to a capital investment project. The Company shall recover the amortized portion of costs incurred by the Company for the implementation of a NWA project plus any applicable incentives.

B. If a NWA project results in the Company displacing a capital project that is reflected in the targets for Average Electric Plant in Service Balances under the Net Plant Reconciliation, the target(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge associated with the displaced project will be applied as a credit against the recovery of the associated NWA project costs. In the event that the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NWA project costs, the difference will be deferred for the benefit of customers.

C. Cost Allocation
The costs will be allocated to each service class based on the following allocators:
(1) coincident peak demand for the transmission portion (if any) of the deferred traditional project; and
(2) non-coincident peak demand allocator for the sub-transmission and distribution portions of the deferred traditional project.

Once allocated to each applicable service class, the costs will be recovered through a component of the Transition Charge. If an NWA project will benefit only certain service classes, the cost allocation will be limited to the benefitted classes.

D. The NWA Surcharge is applicable to customers taking service under Service Classification Nos.: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, and 14, regardless of supplier.

E. Filings and Statements
A NWA Statement setting forth the NWA Surcharge rates shall be filed with the Commission on not less than 30 days' notice. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

33. Electric Vehicle ("EV") Make Ready Surcharge ("EV Surcharge")

The Electric Vehicle ("EV") Make-Ready Surcharge is to recover the costs associated with the make-ready programs administered by the Company or by NYSERDA as described below.

A. Programs

1. Utility-Owned Make-Ready Work
The depreciation expense related to utility-owned make-ready costs, including work related to future-proofing Company infrastructure, and the return on the average unrecovered portion of such investment, net of deferred income taxes, shall be collected and amortized over the subsequent one-year period, including carrying charges at the Company's pre-taxed weighted average cost of capital.

2. Customer-Owned Make-Ready Work
Incentives paid for customer-owned make-ready work, including carrying charges calculated at the Company's currently authorized pre-tax cost of capital applied to the net-of-tax balances of such incentives and carrying charges, shall be recovered over a period of 15 years;

3. Make-Ready Implementation Costs
Implementation costs inclusive of the Fleet Assessment Service, including carrying charges calculated at the Company's currently authorized pre-tax cost of capital applied to the net-of-tax balances of such other costs and carrying charges, shall be recovered over a period of 5 years.

4. EV Managed Charging Program
Costs associated with the EV Managed Charging Program (Rule 37), including carrying charges calculated at the Company's currently authorized pre-tax cost of capital applied to the net-of-tax balances, shall be deferred to the end of each program year and recovered during the subsequent program year.

5. Electric Vehicle Demand Charge Rebate
Rebates paid to customers under the Electric Vehicle Demand Charge Rebate (Rule 38), including carrying charges calculated at the Company's currently authorized pre-tax cost of capital applied to the net-of-tax balances, shall be deferred to the end of each program year and recovered during the subsequent program year.

6. Other Programs
This includes costs associated with the Environmental Justice Community Clean Vehicles Transformation Prize, Clean Personal Mobility Prize, Clean Medium- and Heavy- Duty Innovation Prize, Medium- and Heavy- Duty Make-Ready Pilot Program and Transit Authority Make-Ready Program, and Micromobility Make-Ready Program. To the extent that costs in these programs are for utility-owned make-ready infrastructure, such costs shall be recovered consistent with Utility-Owned Make-Ready Work as noted in (a) above. Other costs of these programs, including carrying charges calculated at the Company's currently authorized pre-tax cost of capital applied to the net-of-tax balances of such other costs and carrying charges, shall be recovered over a period of 15 years.

B. Applicability
The EV Surcharge shall be collected from all customers taking service under Service Classification Nos. 1, 2, 3, 4, 7, 8, 9, 10, 11 and 14, whether receiving electricity supply from the Company or an ESCO.

GENERAL INFORMATION

33. Electric Vehicle ("EV") Make Ready Surcharge ("EV Surcharge")(Cont'd)

C. Costs

1. Costs for the Electric Vehicle Make-Ready Programs shall be collected from all customers taking electric delivery service, except as provided in D. below, and allocated to service classifications based on delivery service revenues.
2. The EV Surcharge shall be determined by dividing applicable EV Make-Ready Costs by the forecasted billed kWh or kW demand, as applicable, for the collection period.
3. Recovery shall be on a per kWh basis for non-demand customers; on a per kW basis for demand-billed customers; and on a per As-Used basis for Standby customers.

GENERAL INFORMATION

33. Electric Vehicle ("EV") Make Ready Surcharge ("EV Surcharge") (Cont'd)

C. Costs (Cont'd)

4. The EV Surcharge collected from customers will be subject to an annual reconciliation for any over or under collections from the previous year. The EV reconciliation over- or under-collections will be credited or surcharged to customers.
5. Cost recovery will be on an annual basis to be effective with the first billing batch in February, with the first program year ending December 31, 2020 and each subsequent program year comprising a successive annual term thereafter.

D. Exceptions

A customer that qualifies for the Excelsior Jobs Program as provided in Rule 4.L.3 is exempt from paying the EV Surcharge.

E. Billing and Filing of Statement

1. The EV Surcharge shall be included in the Transition Charge on customer bills.
2. An Electric Vehicle Statement ("EVMR") setting forth the EV Surcharge rates shall be filed with the Public Service Commission on not less than 15 days' notice to be effective February 1. Such statement can be found at the end of this Schedule (P.S.C. No. 19 – Electricity).

34. New York Power Authority ("NYPA") Program to Contribute to Existing Economic Development Customers and Serve New Governmental Entities

A. Pursuant to Public Authorities Law ("PAL") § 1005, Subsection 27, NYPA is authorized to address the energy related needs of the following types of customers as defined within PAL§ 1005, Subsection 27.

B. To address the customer's energy needs, NYPA may:
   a. supply power and energy procured from competitive market sources; or
   b. supply renewable power, energy, or related credits or attributes procured through a competitive process, from competitive market sources, or through negotiation when a competitive procurement is not reasonably feasible and such products can be procured on reasonably competitive terms

C. NYPA not authorized to act as a CCA Administrator.

D. A customer that elects to participate in this Program shall be subject to the Delivery Charges listed within the customer's Service Classification, the Revenue Decoupling Mechanism Adjustment Charge, the Transition Charge (Non-Bypassable Charge ["NBC"]), and the Rate Adjustment Mechanism Surcharge.

E. Surcharges:

The System Benefits Charge and Clean Energy Standard Surcharge apply to electricity supplied under this Program.

F. Supply

Customers who take service under this Program shall have their electric power supplied by NYPA pursuant to the customer's contract with NYPA; however, NYPA shall provide all of the customer's electric power supply if the customer elects the ESCO Supply Service (*i.e.*, load shall not be split between NYPA and an ESCO). If a customer chooses to no longer take service under this Rule, the customer may choose to take their electric power supply from: (a) an ESCO or become a Direct Customer; or (b) the Company in accordance with the rates and charges contained in the service classification under which the customer takes service. Customers taking service under this Rule are not subject to the Supply Charge and the Merchant Function Charge.

GENERAL INFORMATION

35. Remote Crediting ("RC") Program

A. Eligibility

1. A non-residential customer and farm residential, who owns or operates electric generating equipment ("Facility"), and as defined in Public Service Law ("PSL") §66-j or PSL§66-l, limited in size as set forth in the table below will be permitted to participate as a Remote Crediting Host in this program:

Generator Type	Size Limit on System	
	Residential	Non-Residential
Solar	Up to 5 MW	
Micro-hydroelectric	Up to 5 MW	
Fuel Cell	Up to 5 MW	
Farm Waste	Up to 5 MW	
Wind	Up to 5 MW	
Farm Wind	Up to 5 MW	

2. A customer participating in Remote Net Metering ("RNM") pursuant to Rule 28 and is compensated for excess generation based on Rule 26.B, Value Stack shall be transitioned to Remote Crediting pursuant to this Rule effective with the Host's first full billing cycle after September 1, 2021.
3. A project that is participating in Remote Net Metering and is compensated based on volumetric or monetary crediting may make a one-time irrevocable election to opt-in to the Remote Crediting Program as set forth below:
    a. A non-Value Stack RNM project may opt into the Value Stack and shall adhere to the rules and requirements of Remote Crediting.
    b. A Host of a RNM project that transitions to Remote Crediting will retain any Value Stack Eligibility Date lock-in rates, as described in Rule 40.B, as well as the project's originally-established term limit.
    c. A Host of a RNM project that is compensated based on volumetric crediting and opts into Remote Crediting shall forfeit any banked credits on the existing project before commencing with Remote Crediting, and such project's Value Stack Eligibility Date shall be the date in which the project opts into Remote Crediting.
    d. A Host of a RNM project that is compensated based on monetary crediting and has banked credits that opts into Remote Crediting, before commencing with Remote Crediting, such banked credits shall be transitioned to the Host Bank as its starting balance.
4. A customer account that is participating in the Remote Crediting program as a Host or a Satellite Account may not also participate in Community Distributed Generation ("CDG"), Rule 23 or Remote Net Metering, Rule 28.
5. Interconnected CDG projects, including Net Crediting, shall have the option to switch to Remote Crediting through a one-time irrevocable electric as detailed in Rule 35.H.
6. A customer that takes service pursuant to Service Classification No. 14 is not eligible to participate in the Remote Crediting program.
7. Remote Crediting Host and Satellite Accounts must be located in the Company's service territory.

GENERAL INFORMATION

35. Remote Crediting ("RC") Program

B. Remote Crediting Host Requirements
   1. The Remote Crediting Host that meets the Eligibility requirements set forth above shall submit an application to the Company and designate up to ten (10) autonomous customers, including the Host Account, to participate in Remote Crediting.
   2. The Remote Crediting Host must certify in writing to the Company, both prior to commencing service under Remote Crediting and annually thereafter, that it has met all program criteria set forth in the Commission's Orders, including but not limited to certifying that they can satisfy all obligations assumed with respect to Satellite Account members and other requirements established by the Commission.
   3. A Remote Crediting Host Account may not participate in other Remote Crediting projects as a Remote Crediting Satellite Account.
   4. Monthly Allocation File
      a. If no allocation form is provided to the Company within thirty (30) days of interconnection to the Company's distribution system, all Value Stack compensation will be applied to the electric charges of the Host Account and any excess credits will be allocated to the Host bank until such time a completed allocation form is received by the Company. The excess credit shall continue to be banked and available for future host bank allocation.
      b. The initial valid allocation request shall be effective with the first full Remote Crediting Host Account billing period from the later of 60 days after receipt of such request or effective date of interconnection.
      c. The Remote Crediting Host shall allocate, on a percentage basis (at up to three decimal places of accuracy), its monthly Value Stack credits to each of the project's Satellite Accounts, as well as the Host Account, such that the allocation totals 100 percent. The Remote Crediting Host may allocate 0.000% to their Host Account. Allocations that total more than 100 percent shall be rejected.
         i. Subsequent valid allocation files shall be effective the with next full Remote Crediting Host Account billing period 30 days after receipt of such request.
         ii. The Remote Crediting Host may not modify the allocation file more than once in a 30-day period.
         iii. If the allocation file does not include instructions for disbursements from the Host Bank, no disbursement will be made from the Host Bank.

C. Satellite Requirements
   1. A Remote Crediting project may have up to ten (10) autonomous customers, including the Host Account
      a. A Satellite customer may have multiple accounts identified on the monthly allocation file.
   2. A Remote Crediting Satellite account may participate as a satellite in more than one Remote Crediting project. The aggregated rated capacity of generating equipment of Remote Crediting Host Account(s) designated to serve a Remote Crediting Satellite Account plus the rated capacity of net-metered generating equipment on the Remote Crediting Satellite Account, if any, cannot exceed 5,000 kW.
      a. If it's determined that the Satellite customer is receiving more than the aggregated capacity of 5,000 kW, the Company shall suspend any application of credits to the Satellite and those credits will remain with the appropriate Host. Application of credits to the Satellite will commence once the sum of the Host allocations does not exceed 5,000 kW.

GENERAL INFORMATION

35. Remote Crediting ("RC") Program

D. Calculation and Application of Credits

1. The Company shall calculate credits in accordance with Rule 26.B. Value of Distributed Energy Resources, Value Stack for the Facility and allocate credits in accordance with the percent allocations provided by the Remote Crediting Host.
2. The credit applied to each account (*i.e.*, Host Account and Satellite Account) shall not exceed the current electric charges. Any remaining unused credits for that account will be banked and carried over on the account for its next billing period.
3. Banked credits remaining on the Remote Crediting Host account at the end of the billing period will be available to offset the Remote Crediting Host's electric charges on its next bill, or for future host bank disbursement to participating satellite accounts according to instructions provided to the Company in Rule 35.B.4.c.iv.
4. Satellite Account
    a. If a Remote Crediting Satellite participates in multiple Remote Crediting projects, the Value Stack credit applied to the Satellite account's current electric charges will be determined on a prorata basis based on each Remote Crediting Host's total allocation to the Satellite in the month, inclusive of Host bank allocation, applied to the Satellite's current electric charges.
    b. If a Remote Crediting Satellite is a customer-generator, any on-site generation credits will be applied to the satellite's bill before applying any credits from the Remote Crediting project.

E. Metering Requirements

See Rule 13.C, Distributed Energy Resources, for applicable metering requirements.

F. Discontinuance of Participation in Remote Crediting Project

1. If a Remote Crediting Satellite discontinues participation in a Remote Crediting project:
    a. The Company shall rely on the Remote Crediting Host's monthly allocation form to verify the Remote Crediting Satellite Account's participation in the Remote Crediting Host's project. When the Company processes the Remote Crediting allocation form, that no longer includes the Remote Crediting Satellite Account, the Company shall transfer any banked credits of the Remote Crediting Satellite Account to the Remote Crediting Host Account.
    b. Once remaining credits have been transferred to the Remote Crediting Host of a project, the Company shall not be responsible for any additional refunds or credits owed to the Remote Crediting Satellite Account for that Remote Crediting project.
    c. A Remote Crediting Satellite Account that has been removed from a Remote Crediting Host project, but continues to maintain an active utility account, may not subscribe to a new Remote Crediting Host or Remote Crediting Net Crediting project until the billing period after which all banked credits are returned to the original Remote Crediting Host's Account.

GENERAL INFORMATION

35. Remote Crediting ("RC") Program

G. Account Closure

1. Host Account
   a. The Company shall require an actual meter reading to close an Account pursuant to this Rule.
   b. The Company shall close an account on the earlier of: (a) the first cycle date on which a reading is taken following the requested turn off date, or (b) the date of a special reading, which a Customer may request at the charge specified in General Information Rule 11.7.C.(c).
   c. After the Host Account's final bill is rendered, or at the end of the term of service, the Remote Crediting Host will forfeit any remaining credit in the host bank and shall not be cashed out or transferred.
2. Satellite Account
   a. The Company shall require an actual meter reading to close an account pursuant to this Rule.
   b. The Company shall close an account on the earlier of:
      i. the first cycle date on which a reading is taken following the requested turn off date, or
      ii. the date of a special reading, which a Customer may request at the charge specified in General Information Section 11.7.C.(c).
   c. Once the Remote Crediting Satellite has closed their account and the final bill rendered, the banked credits that were remaining on the Remote Crediting Satellite's account shall be transferred back to the Remote Crediting Host Account.
   d. If the Remote Crediting Satellite was participating in multiple Remote Crediting projects, the credits shall be returned to each host in the proportioned percent of installed capacity allocated to that account in each project.
   e. Once remaining credits have been transferred to the Remote Crediting Host of a project, the Company shall not be responsible for any additional refunds or credits owed to the Remote Crediting Satellite Account for that Remote Crediting project.

H. One-Time Voluntary Switch:

A customer shall have the option to make a one-time voluntary switch from Remote Crediting to Community Distributed Generation (Rule 23). The procedure to switch is detailed in the CDG VDER Procedural Requirements manual posted on the Company's website.

   a. A customer shall provide the Company with notice of their intent to switch and submit a switching certification and a CDG/Remote Crediting allocation form within 60 days of the new project's first account billing date or within 45 days of the existing project's last host account billing date.
      (i) The project shall remain under the Value Stack compensation mechanism as described in Rule 26.B.10.
      (ii) This switch shall be irrevocable.
   b. If a customer chooses to make a one-time voluntary switch, the component rates that were established on the customers eligibility date shall not change and all project elections shall carry forward.
   c. The compensation term shall be that of the program that a customer is switching into and begins on the project's original interconnection date.

GENERAL INFORMATION

35. Remote Crediting ("RC") Program

H. One-Time Voluntary Switch (Cont'd):

d. The customer shall retain any monetary credits banked on the host account; this shall be the starting balance of the new host bank.
e. For projects switching to Remote Crediting and choose to receive compensation under the Environmental Component, the project owner shall contact the NYGATS administrator to initiate a transfer of the generator in NYGATS to the Company. Projects not already authorized in NYGATS must authorize the Company to register and report data through NYGATS.

GENERAL INFORMATION

36. Arrears Relief Program

A. One-Time Arrears Relief Credit:

1. Phase 1 Arrears Reduction Program ("Phase 1"):
A low-income customer with arrears as of May 1, 2022, may be eligible for a one-time arrears relief credit as set forth in the Public Service Commission's Order in Case No. 14-M-0565 dated June 16, 2022.

2. Phase 2 Arrears Reduction Program ("Phase 2"):
A residential customer or a small-commercial customer with arrears as of May 1, 2022, may be eligible for a one-time arrears relief credit as set forth in the Public Service Commission's Order in Case No. 14-M-0565 dated January 19, 2023.

B. Arrears Relief Program Surcharge

The Arrears Relief Program Surcharge is designed to recover the remaining program costs related to the arrears management plan and associated carrying charges after applying the allocated funds provided by the Utility Arrears Relief Program.

1. Applicability:
The Arrears Relief Program Surcharge is applicable to all customers taking service under Service Classification Nos. 1, 2, 3, 4, 6, 7, 8, 9, and 14.

2. Calculation:
The surcharge shall be calculated by dividing the allocated costs for each service classification by the forecasted sales or the demand for the service classification. The amounts to be recovered shall be assessed carrying charges at the Company's weighted pre-tax cost of capital. Costs associated with Phase 1 shall be recovered over a five-year period. Costs associated with Phase 2 shall be recovered over a three-and-a-half-year period.

3. Cost Allocation:
The costs to be collected shall be allocated to each service classification consistent with the uncollectable cost allocation from the Company's most recent cost of service study.

4. Cost Recovery:
The surcharge shall be recovered from customers on a per kWh basis for non-demand service classes, on a per kW basis for demand service classes, and on a per As-Used demand basis for SC 14.

GENERAL INFORMATION

36. Arrears Relief Program (Cont'd)

B. Arrears Relief Program Surcharge (Cont'd)

The Arrears Relief Program Surcharge is designed to recover the remaining program costs related to the arrears management plan and associated carrying charges after applying the allocated funds provided by the Utility Arrears Relief Program.

5. Reconciliation:
The surcharge collected from customers shall be subject to an annual reconciliation for any over- or under-collection at the end of the annual collection period, inclusive of carrying charges at the Company's weighted pre-tax cost of capital, to be included in the balance for refund or recovery in the next annual period. The first Phase 2 reconciliation shall be calculated concurrently with the Phase 1 reconciliation and annually thereafter.

6. Billing and Statement:
For purposes of billing, the surcharge shall be included in the Transition Charge.

An Arrears Relief Program Statement ("ARP") setting forth the Arrears Relief Program Surcharge rates, for Phase 1 and Phase 2, shall be filed with the Public Service Commission on not less than 3-days' notice. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

37. EV Managed Charging Program

A. Eligibility:

1. A residential customer, as defined by HEFPA, taking service under Service Classification No. 1 who owns or leases a plug-in hybrid or battery electric vehicle is eligible for this program subject to the program requirements in the EV Managed Charging Implementation Plan posted on the Company's website.
2. A customer must participate in the program for a minimum of 12-months to be eligible for the enrollment and participation incentives described in Rule 37.B below.
3. Eligible customers may participate in this program through December 31, 2025.

B. Program Tiers and Incentives:

1. Baseline Tier:
   i. Enrollment Incentive: A customer shall receive a one-time $25 enrollment incentive for enrolling in the Baseline Tier of the managed charging program.
   ii. Participation Incentive: A customer shall receive the Participation Incentive if the customer charges off-peak, 9:00 P.M. to 7:00 A.M. Eastern Standard Time, 80% or more for the calendar month. The Participation Incentive shall be the difference between the Service Classification No. 1 delivery and supply rates for the month and the Service Classification No. 4 – PEV delivery and supply rates for the month multiplied by the kWh used off-peak measured by the customers vehicle telematics system or charger. A customer that does not achieve the 80% threshold in any given month shall not earn an incentive for that month, however, the customer shall be able to earn the participation incentive in any of following months if they achieve the 80% threshold.

2. Advanced Tier:
   i. Enrollment Incentive: A customer shall receive a one-time $150 enrollment incentive for enrolling in the Advanced Tier of the managed charging program.
   ii. Participation Incentive: The Participation Incentive shall be the difference between the Service Classification No. 1 delivery and supply rates for the month and the Service Classification No. 4 – PEV delivery and supply rates for the month multiplied by the kWh used off-peak measured by the customers vehicle telematics system or charger. A customer shall receive the incentive, assessed on a month-to-month basis, if the customer maintains an active daily charging schedule and agrees to allow active managed charging of their vehicles by the Company. A customer shall not override their managed charging schedule resulting in an on-peak charging event greater than fifteen (15) minutes and more than three (3) times per month.

3. Specific information on the program shall be set forth in the EV Managed Charging Implementation Plan posted on the Company's website.

C. Cost Recovery:

1. Program implementation costs, enrollment incentives, and participation incentives shall be recovered through the EV Make-Ready Surcharge (Rule 33).

GENERAL INFORMATION

38. Electric Vehicle Demand Charge Rebate

A. Eligibility

A customer served under Service Classification Nos. 3, 7, 8 or 9 that installs and operates electric vehicle charging equipment may apply and qualify for the Electric Vehicle ("EV") Demand Charge Rebate subject to the following conditions:

i. A customer operating electric vehicle charging equipment must have a Charging Ratio of 50 percent or greater in order to be eligible for the EV Demand Charge Rebate.
    a. For a customer that chooses to separately meter their EV charging load, the Charging Ratio shall be equal to 100 percent.
ii. A customer currently enrolled in the Excelsior Jobs Program pursuant to Rule 4.L.3 of this Schedule is ineligible for the EV Demand Charge Rebate.
iii. A customer currently participating in the Company's Per-Plug Incentive ("PPI") Program is ineligible for the EV Demand Charge Rebate.
    a. A customer participating in the Company's PPI Program shall have a one-time option to either continue participating in the PPI Program for the remainder of the Customer's eligibility period or to receive the EV Demand Charge Rebate.

B. Rebate Determination and Issuance

i. Charging Ratio is defined as the ratio of the sum of the EV charging nameplate capacity in kW to the sum of the customer's maximum simultaneous demand of all onsite load in kW, including electric vehicle charging load.
    a. The maximum simultaneous demand of all load (in kW) onsite will be determined from the most recent Electrical Load Form on the account. The Electrical Load Form provides the customer's anticipated on-site load from all electrical equipment sources and is general submitted by a customer when requesting new or upgraded electric service.
    b. The Company may request an updated Electrical Load Form at any point in time that is subsequent to the customer's interconnection of the electric vehicle charging equipment for the purposes of determining eligibility.
    c. The Charging Ratio shall be determined at the time of application and shall remain the Charging Ratio until such time that the customer provides a new Electrical Load Form if adding or removing load.
    d. The Company reserves the right to re-evaluate the Charging Ratio and eligibility subsequent to application for, or a change in electric service.
    e. The calculation of the Demand Charge Rebate shall not include delivery surcharges, supply charges, supply surcharges, or any other demand-measured charges included on a customer's bill.
ii. For a customer with a Charging Ratio of 50 percent or greater, the Rebate will be calculated for each billing period by taking the billed Demand Charge times the Charging Ratio times 50 percent.
iii. The Rebate shall be issued separately from the customer's bill on a quarterly basis.

GENERAL INFORMATION

38. Electric Vehicle Demand Charge Rebate

C. Cost Recovery

   i. Rebates paid to customers shall be recovered through the EV Make-Ready Surcharge (Rule 33) and shall be allocated among service classifications using the transmission and distribution revenue allocator as set forth in the Commission's Order dated January 19, 2023, issued under Case 22-E-0236.

D. Beginning October 17, 2025, this Rule shall no longer be available to new customers and a customer receiving rebate payments under this Rule that has elected to participate in the Electric Vehicle Phase-In Rate (Rule 19) shall continue to receive the Demand Charge Rebate until the first monthly billing period in which the customer is billed the Electric Vehicle Phase-In Rate.

   i. A customer receiving rebate payments under this Rule that has not responded to the Company's outreach regarding the Electric Vehicle Phase-In Rate (Rule 19) shall be eligible to continue receiving rebate payments until December 16, 2025, at which point this Rule shall no longer be available to any customers.

GENERAL INFORMATION

39. Statewide Solar For All ("S-SFA") Program

A customer participating in the Company's Low-Income Program, as specified in Rule 4.U, that also resides within an area deemed to be a Disadvantaged Community ("DAC") by the Climate Justice Working Group ("CJWG"), which may be modified at the discretion of the CJWG may receive a monthly credit under the S-SFA Program.

a. Definitions:

Credit Pool: is the sum of all S-SFA Projects' Customer Share throughout the Program Year, plus any returned Utility Administration Fee. Any associated carrying charges shall based on the Company's pre-tax Weighted Average Cost of Capital (WACC) to the balance of the Credit Pool throughout the Program Year. The Credit Pool balance as of November 1st of each year shall be used in the calculation of the monthly S-SFA Customer Credit.

Customer Share: is the amount of Value Stack compensation that remains after the S-SFA Project Payment, and the Utility Administration Fee.

S-SFA Program Year: December 1st to November 30th of the following year.

S-SFA Project Compensation Level: percentage of the total Value Stack compensation, in accordance with Rule 26.B, paid to the participating project that is determined at the time of project enrollment.

S-SFA Project Payment: Monthly payment made to eligible Value Stack projects participating in S-SFA.

Utility Administration Fee: a fee to offset incremental costs incurred to implement and administer the S-SFA Program.

GENERAL INFORMATION

39. Statewide Solar For All ("S-SFA") Program (Cont'd)

b. Project Eligibility

i. Starting December 1, 2024, non-operational projects that qualify for Value Stack, as determined in accordance with Rule 26.B, may elect to participate in S-SFA upon satisfaction of the 25% interconnection cost responsibility set forth in the Addendum-SIR, or when an SIR Contract has been executed, if no such obligation is required.
   a) Projects electing to participate in the S-SFA Program are ineligible to receive the Community Adder ("CA"), Community Credit ("CC"), Market Transition Credit ("MTC"), or the Inclusive Community Solar Adder ("ICSA"), except as described below.

ii. Non-operational projects that have submitted their 25% interconnection deposit or an SIR Contract has been executed, if no such payment is required, prior to December 1, 2024, have a one-time option to elect to participate in the S-SFA Program by March 31, 2025, with the following restrictions:
   a) Projects awarded the CA, CC, or MTC must have received this NY-Sun incentive award prior to March 1, 2025.
   b) Projects awarded the ICSA must forgo the ICSA award upon enrolling in the S-SFA Program.
   c) Such projects will receive a reduced Compensation Level, as determined by NYSERDA annually, and as set forth in the S-SFA Compensation Statement.

iii. The S-SFA eligible technologies pursuant to the size limits under Rule 26.B are as follows:
   a) Solar
   b) Standalone Energy Storage
   c) Co-located Solar and Energy Storage

iv. Value Stack-eligible Standalone Energy Storage projects, as described in Rule 26.B, are eligible to participate in the S-SFA Program.
   a) Such projects will receive a Compensation Level specific to energy storage projects, as determined by NYSERDA, and as set forth in the S-SFA Compensation Statement.

v. The S-SFA Project shall complete a SSFA Project Participation Agreement with the Company.

vi. The S-SFA Project shall provide the necessary information as provided in the S-SFA Procedural Requirements for the Company to pay the project.

vii. The S-SFA Project must be current on their utility account to be eligible and participate in S-SFA.

GENERAL INFORMATION

39. Statewide Solar For All ("S-SFA") Program (Cont'd)

c. S-SFA Program Customers:
   i. Enrollment:
      a) The Company will automatically enroll any customer participating in the Company's Low Income Program (Energy Affordability Program ("EAP")) that also resides within a DAC in the S-SFA Program.
      b) EAP customers that reside within a DAC that are enrolled in a Community Choice Aggregation related product, shall be permitted to participate in both the S-SFA Program and Community Choice Aggregation.
   ii. Opt-out Procedure and Unenrollment:
      a) S-SFA Program customers may opt-out of the S-SFA Program at any time via telephone by contacting the Company's contact center or by visiting nyseg.com.
      b) If a customer opts-out during a Program Year, such customer shall receive a final S-SFA credit during the current month of the opt-out and shall not receive any further credits in subsequent bills.
      c) S-SFA Program customers will also be removed from the S-SFA Program at such time that the customer is no longer a participant in the Company's EAP or if the customer is a participant in the Company's EAP but no longer resides within a DAC.
   iii. Dual-Participation
      a) A customer that receives S-SFA credits shall also be eligible to participate in Community Distributed Generation ("CDG") as a satellite customer in accordance with Rule 23.

d. S-SFA Customer Credit Calculation:
   i. Beginning with the December 2025 Program Year, the Company shall determine the fixed dollar amount that will be credited to participating S-SFA Program customers' total electric charges on a monthly basis for the upcoming Program Year ("S-SFA Customer Credit").
   ii. The monthly S-SFA Customer Credit will be determined as:
      a) S-SFA Customer Credit = Credit Pool / (number of S-SFA Customers enrolled at end of previous Program Year / number of billing months in the Program Year in which customers receive the S-SFA Customer Credit)
      b) Any overcollection of the S-SFA Utility Administration Fee compared to actual administrative and implementation costs shall be added to the Credit Pool for disbursement to S-SFA Program Customers.
   iii. The S-SFA Customer Credit will be applied to the electric portion of customers' bills, after the application of any other applicable customer bill credits, for billing periods ending on or after December 1, 2025.
   iv. If the S-SFA Customer Credit causes a customer's monthly bill to be less than zero, the amount less than zero caused by the S-SFA Customer Credit will be banked to a customer's account and applied to future bills.
      a) If a customer closes their account with a negative balance that was the result of S-SFA Customer Credits, such credit shall be returned to the Credit Pool.

GENERAL INFORMATION

39. Statewide Solar For All ("S-SFA") Program (Cont'd)

i. Statements

   i. The S-SFA Customer Credit statement shall be filed annually with the Public Service Commission on not less than fifteen (15) days' notice to become effective December 1st of each year, beginning in 2025. Such statement may be found at the end of this Schedule.
   ii. The Compensation Level percentages, as specified by NYSERDA, shall be filed annually with the Commission in the S-SFA Compensation Statement on not less than three (3) days' notice to become effective December 1st of each year. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

40. Renewable Energy Access and Community Help Program ("REACH") Program

A customer participating in the Company's Low-Income Program, as specified in Rule 4.U, that also resides within an area deemed to be a Disadvantaged Community ("DAC") by the Climate Justice Working Group ("CJWG"), which may be modified at the discretion of the CJWG may receive a monthly credit under the REACH Program.

a. Definitions:

Customer Share: is the amount of Value Stack compensation that remains after the Small-Scale REACH Project Payment, and the Utility Administration Fee.

Large-Scale REACH Projects: Renewable energy projects or bulk energy storage projects sized greater than 5 MW that participate in the REACH Program through direct coordination with the New York Power Authority ("NYPA").

REACH Credit Pool: is the sum of all Small-Scale REACH Projects' Customer Share revenue in addition to the revenue received from NYPA for Large-Scale REACH Projects and Third-Party Participants, plus any returned Utility Administration Fee. Any associated carrying charges shall be applied based on the Company's pre-tax Weighted Average Cost of Capital (WACC) to the balance of the REACH Credit Pool throughout the year. The REACH Credit Pool balance as of November 1st of each year shall be used in the calculation of the monthly REACH Customer Credit.

REACH Project Compensation Level: percentage of the total Value Stack compensation, in accordance with Rule 26.B, paid to NYPA or their designee that is determined at the time of project enrollment.

REACH Project Payment: Monthly payment made to NYPA or their designee participating in REACH.

Small-Scale REACH Projects: Renewable energy projects sized 5 MW or less that are planned, designed, developed, financed, constructed, owned, operated, maintained or improved, or contracted for by the NYPA as a renewable energy project participating in the REACH Program as authorized by Public Service Law §66-p.

Third-Party Participants: Third parties participating in the REACH Program through direct coordination with NYPA.

Utility Administration Fee: a fee to offset incremental costs incurred to implement and administer the REACH Program.

GENERAL INFORMATION

40. Renewable Energy Access and Community Help Program ("REACH") Program (Cont'd)

b. Project Eligibility:

i. Small-Scale REACH Projects are eligible for the REACH Program subject to the conditions below:
   1. Non-Operational Projects
      a. Small-Scale REACH Projects that have satisfied the 25% interconnection cost responsibility set forth in the Addendum-SIR, or when an SIR Contract has been executed, if no such obligation is required, may elect to participate in the REACH program at that time.
      b. Small-Scale REACH Projects must qualify for Value Stack compensation pursuant to the eligibility requirements set forth in Rule 26.B.
      c. Small-Scale REACH Projects electing to participate must forgo the following awarded NY-Sun incentives: Community Adder ("CA"), Community Credit ("CC"), Market Transition Charge ("MTC"), or the Inclusive Community Solar Adder ("ICSA").
   2. Operational Projects
      a. Small-Scale REACH Projects owned, operated, maintained or improved, or contracted for by NYPA may transition from Value Stack Community Distributed Generation (Rule 23) to the REACH Program.
      b. NYPA must make the Company aware of the intent to enroll such projects in the REACH Program by submitting to the Company an allocation form with no subscriber accounts at least 60 days prior to date in which the project wishes to participate in the REACH Program.
      c. The monetary amount in a transitioning Small-Scale REACH Project's host bank at the time of transition would be split between the REACH Project Payment, REACH Credit Pool, and the Utility Administration Fee, based on the current Compensation Level set forth on the effective S-SFA Compensation Statement found at the end of this Schedule.

ii. The Small-Scale REACH Project shall complete a REACH Project Participation Agreement with the Company.

iii. The Small-Scale REACH Project shall provide the necessary information as provided in the REACH Procedural Requirements for the Company to pay the project.

iv. The Small-Scale REACH Project must be current on their utility account to be eligible and participate in REACH.

v. The Company shall confirm a Small-Scale REACH Projects eligibility with NYPA prior to enrollment.

c. REACH Program Customers

The REACH Program shall provide a monthly credit to eligible customers participating in the Statewide Solar for All Program pursuant to Rule 39. All limitations and policies specified in Rule 39 apply to REACH program recipients including dual participation and removal from the program.

GENERAL INFORMATION

40. Renewable Energy Access and Community Help Program ("REACH") Program (Cont'd)

d. REACH Customer Credit Calculation
   i. The Company shall determine the fixed dollar amount that will be credited to participating REACH Program Customers' total electric charges on a monthly basis for the upcoming year.
   ii. The monthly REACH Customer Credit will be determined as:
      a) REACH Customer Credit = REACH Credit Pool / (number of eligible REACH Program Customers at the time of the REACH Customer Credit calculation / number of billing months in which customers will receive the REACH Customer Credit)
      b) Any overcollection of the Utility Administration Fee compared to actual administrative and implementation costs shall be added to the REACH Credit Pool for disbursement to REACH Program Customers.
      c) The REACH Customer Credit shall be aggregated with the S-SFA Customer Credit (Rule 39) and shall be displayed on a customer's bill as "S-SFA/REACH".
   iii. The REACH Customer Credit will be applied to the electric portion of customers' bills, after the application of any other applicable customer bill credits.
   iv. If the REACH Customer Credit causes a customer's monthly bill to be less than zero, the amount less than zero caused by the REACH Customer Credit will be banked to a customer's account and applied to future bills.
      a) If a customer closes their account with a negative balance that was the result of a REACH Customer Credit, such credit shall be returned to the Credit Pool.
   v. By October 1 of each year, beginning in 2026, NYPA shall distribute to the Company the allocated revenues from Large-Scale REACH Projects and Third-Party Participants accumulated over the previous year.
      a) The Company shall include Large-Scale REACH Project and Third-Party Participant revenue received from NYPA in the REACH Credit Pool.

e. REACH Project Compensation Methodology
   i. The compensation for the REACH Project shall be in accordance with Rule 26.B. Value Stack, multiplied by the project's established Compensation Level.

GENERAL INFORMATION

40. Renewable Energy Access and Community Help Program ("REACH") Program (Cont'd)

f. REACH Project Compensation Level and Payment
   i. The REACH Project Compensation Level shall be assigned to a Small-Scale REACH Project at the time the project has satisfied the 25% interconnection cost responsibility set forth in the Addendum-SIR, or when an SIR Contract has been executed, if no such obligation is required, based on the current New York State Energy Resource and Development Authority ("NYSERDA") Standard Offer.
      1. The Standard Offer accepted by a project shall remain with the project for a period of 25 years.
   ii. Standard Offer Compensation Levels shall be set by the NYSERDA and reviewed at least annually by Department of Public Service Staff ("DPS Staff").
   iii. Payments to NYPA or their designee shall be issued within 40 days from the end of the Small-Scale REACH Project bill date.
   iv. The Small-Scale REACH Project must be current on their utility account tied to the project.
   v. The payment shall not be reduced for amounts owed to the Company on the retail bill. However, the Company shall withhold payments until the Small-Scale REACH Project is current on their utility account.
   vi. NYPA shall provide the Company with the necessary information for the Company to pay the compensation in the REACH Participation Agreement.

g. REACH Project Unenrollment
   i. A participating Small-Scale REACH Project may unenroll from the REACH Program with a minimum of twelve (12) months' notice. Small-Scale REACH Projects that unenroll retain any Value Stack component rates locked-in at time of interconnection.
   ii. Payments based on the Compensation Level will expire at such time that the Small-Scale REACH Project terminates participation in the REACH Program or has reached the end of the 25-year compensation period, whichever is sooner.
   iii. If there is a change in account name for the premises on which the Small-Scale REACH Project is located, the new Customer must apply for service under this Rule to receive compensation.
      1. A change in account name shall not reset the 25-year compensation period.

h. Utility Administration Fee
   i. The fee will be one percent of the Value Stack compensation of each Small-Scale REACH Project and one percent of revenue received from NYPA for Large-Scale REACH Projects and Third-Party Participants.

i. Statement
   i. The REACH Customer Credit statement shall be filed with the Public Service Commission on not less than fifteen (15) days' notice prior to the effective date. Such statement may be found at the end of this Schedule.

GENERAL INFORMATION

41. Recovery Charge

The Company shall implement the Recovery Charge on behalf of a Special Purpose Entity to recover costs that were the content of a Recovery Bond for the purposes of storm recovery costs and shall include the amounts authorized by the Commission to recover Recovery Costs and Financing Costs in accordance with the Commission's Financing Order issued in Case 24-E-0493.

1. Applicability:
The Recovery Charge is applicable to all customers taking service under Service Classification Nos. 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 14, and 15.

2. Definitions:
"Financing Costs: means:(a) interest on and principal of, and redemption premiums, if any, that are payable on Recovery Bonds; (b) any payment approved in the Financing Order and required under an ancillary agreement or other accounts established under the terms of any indenture, ancillary agreement, or other financing documents pertaining to Recovery Bonds; (c) provided that Recovery Bonds shall be the only method used to recover the costs identified in this paragraph, any other cost related to issuing, supporting, repaying, and servicing Recovery Bonds, including but not limited to servicing fees, accounting and auditing fees, trustee fees, legal fees, consulting fees, administrative fees, placement and underwriting fees, capitalized interest, rating agency fees, and filing fees, including costs related to obtaining a Financing Order; or (d) any federal, state or local taxes, payments in lieu of taxes, franchise fees or license fees imposed on Recovery Charge revenues.

"Financing Order": means the December 19, 2024, Order of the Commission in Case 24-E-0493, which authorizes, among other things: (a) the issuance of Recovery Bonds; (b) the imposition, collection, and periodic adjustments of Recovery Charges; (c) the creation or recognition of recovery property; and/or (d) the sale, assignment, or transfer of recovery property to an assignee.

"Recovery Bonds": means bonds, debentures, notes, certificates of participation, certificates of ownership, or other evidences of indebtedness or ownership that are issued pursuant to an indenture, contract, or other agreement of the Company or its assignee pursuant to a Financing Order, the proceeds of which are used directly or indirectly to provide, recover, finance, or refinance Commission-approved Recovery Costs and Financing Costs, to such level as the Commission may authorize in a financing order, and which are secured by or payable from recovery property, and that have a final maturity date of no longer than twenty years from the original issuance.

"Recovery Charge": the amounts authorized by the Commission in the Financing Order to recover Recovery Costs and Financing Costs.

"Recovery Costs": recovery costs identified for recovery in the Financing Order.

GENERAL INFORMATION

41. Recovery Charge (Cont'd)

3. Cost Allocation:
The Recovery Charge to be collected shall be allocated to service classes based on the current rate year delivery service revenues at the time of the Recovery Charge calculation as approved by the Commission in the Company's current effective rate plan.

4. Cost Recovery:
The Recovery Charge shall be recovered from customers on a per kWh basis for non-demand service classes, on a per kW basis for demand service classes, and on a per On Peak As-Used demand basis for Standby Service customers (SC 14) and Optional Demand Service Rate customers (SC 15), based on each service classifications' forecast sales.

5. Adjustment Mechanism and Mathematical Formula:

a. Adjustment Calculation:

The Company will make adjustments to the Recovery Charge at least semi-annually, beginning no more than six months from issuance of the Bonds and continuing until the legal final maturity date of the Bonds (or any series of Bonds). The Semi-Annual True-up (defined below) and the Quarterly True-up (defined below) will both be performed on a mandatory basis; and the Interim True-up (defined below) will only be performed if the Company projects under collections. For each Semi-Annual True-up, Interim True-up, and any Quarterly True-up, the Company will file with the Commission an adjustment to the Recovery Charge Statement setting forth the Recovery Charge rates not less than five (5) days prior to the effective date of the compliance tariff statement which shall automatically become effective on the effective date set forth in the compliance tariff statement. The Commission's review of any adjustment pursuant to the true-up mechanism will be limited to mathematical or clerical errors and any such errors discovered in such review shall be addressed in a subsequent True-Up adjustment filing.

Semi-Annually, the Company will file a compliance tariff statement (i) to correct for any over-collections or under-collections to date and anticipated to be experienced up to the date of the next annual adjustment and (ii) to ensure that the expected collections of the Recovery Charge are sufficient to pay timely principal and interest on the Bonds when due pursuant to the expected amortization schedule, to make timely payment of all other Ongoing Financing Costs, and, if necessary, to replenish the capital subaccount (the "Semi-Annual True-up"). Additionally, the Company may file at any time an interim compliance tariff statement to ensure that the expected collections of the Recovery Charge are sufficient to pay timely principal and interest on the Bonds when due pursuant to the expected amortization schedule, to make timely payment of all other Ongoing Financing Costs, and, if necessary, to replenish the capital subaccount (the "Interim True-up").

GENERAL INFORMATION

41. Recovery Charge (Cont'd)

5. Adjustment Mechanism and Mathematical Formula (Cont'd):

a. Adjustment Calculation (Cont'd):

Beginning twelve months prior to the scheduled final payment date of the latest maturing tranche of bonds, the Company will file quarterly adjustments (the "Quarterly True-up") to the Recovery Charge to ensure that the Recovery Charge collections will be sufficient to pay timely interest and scheduled principal on the Bonds (or any series of Bonds) and to make timely payment of all other Ongoing Financing Costs.

The Company will, for each Semi-Annual True-Up, Quarterly True-up and Interim True-Up calculate a Recovery Charge for the Bonds in accordance with the True-Up Mechanism:

The Recovery Charge will be calculated as follows:

i. The Company will calculate the Periodic Payment Requirement (as defined below) for the next six-month period, or if shorter the period from the adjustment date (or, in the case of the initial Recovery Charge calculation, the closing date of the Bonds) to and including the next bond payment date, as well as the Periodic Payment Requirement for the next succeeding six month period ending on the following bond payment date (each, a "Payment Period"). The "Periodic Payment Requirement" or "PPR" covers all scheduled (or legally due) payments of principal (including, if any, prior scheduled but unpaid principal payments), interest, replenishment of the capital subaccount (if any), and other ongoing financing costs to be paid during such Payment Period.

ii. The Periodic Billing Requirement (as defined below) will be calculated for the upcoming Payment Period, using the most recent information of the Company regarding write offs, delinquencies, average days sales outstanding data, collection lags, or other collection data, to determine the amount of Recovery Charge revenue that must be billed during that upcoming Payment Period to ensure that sufficient Recovery Charge revenues will be received to satisfy the Periodic Payment Requirement for such Payment Period. Such amount is referred to as the "Periodic Billing Requirement" or "PBR";

iii. The PBR will also be calculated using the most recent information of the Company regarding write offs, delinquencies, average days sales outstanding data, collection lags, or other collection data, to determine the amount of Recovery Charge revenue that must be billed to ensure that sufficient Recovery Charge revenues will be received to satisfy the Periodic Payment Requirement for both the upcoming Payment Period and the next succeeding Payment Period (the "Combined Payment Periods");

iv. The PBR for the upcoming Payment Period and the Combined Payment Periods will each be allocated among the Company's various Customer service classes based on applicable year delivery service revenues from the current rate plan and will subsequently be allocated to Customer service classes based on the delivery service revenue allocators approved by the Commission in the Company's current effective rate plan at the time of the Recovery Charge calculation.

GENERAL INFORMATION

41. Recovery Charge (Cont'd)

5. Adjustment Mechanism and Mathematical Formula (Cont'd):

a. Adjustment Calculation (Cont'd)

v. The Recovery Charges for each Service Class for both the upcoming Payment Period and the Combined Payment Periods are determined on a per kwh basis for non-demand Customers, on a per kw basis for demand billed Customers and on an on-peak as-used demand basis for standby service and optional demand service Customers; and

vi. Finally, after the calculations for the periods described in paragraphs (ii) and (iii) above are made, the rates that return the higher overall revenue based on the forecasted billing units for the upcoming six-month effective rate period will be the Recovery Charge effective on the next adjustment date.

All true-up adjustments to the Recovery Charges will ensure the billing of Recovery Charges necessary to satisfy the Periodic Payment Requirement for the Bonds for each Payment Period during such 12-month period (or shorter period) following the adjustment date of the Recovery Charge. True-up adjustments will be based upon the cumulative differences (either positive or negative), regardless of the reason, between the Periodic Payment Requirement and the actual amount of Recovery Charge collections remitted to the trustee for the Bonds.

6. Billing and Statement

A Recovery Charge Statement setting forth the Recovery Charge rates shall be filed with the Public Service Commission not less than five (5) days' prior to the effective date. Such statement can be found at the end of this Schedule (P.S.C. 19 – Electricity).