VILLAGE/TOWN OF MOUNT KISCO
WESTCHESTER COUNTY, NEW YORK
104 Main Street
Mount Kisco, New York 10549-0150

Telephone
(914) 241-0500

March 6, 2024

The Ambleside Pub
23 E Main Street
Mount Kisco, CT 06513

RECEIVED
MAY 28 2024
Zoning Board of Appeals
Village/Town of Mount Kisco

Re: Notice of Denial – Sign Permit Application – The Ambleside Pub
23 (23-27) Main Street, Property ID#: 69.81-2-5

To Whom It May Concern:

Please be notified that your sign permit application, on behalf of The Ambleside Pub, to install new signage at the above captioned property is hereby denied. This denial based on the following facts:

- The subject property is located in the CB-1 Zoning District, and is therefore subject to the regulations of the Village Signage District
- Section 89-11A(4) of the Code of the Village/Town of Mount Kisco states that "The types of signs permitted and the regulation of the number, placement, and use of signs is hereby established. No sign shall be erected unless it conforms to the specifications for signs in that sign district, nor shall any sign be used for any purpose or in any manner except as permitted by the regulations for the district in which such sign is to be located or maintained."
- Your application proposes a double-sided, projecting wall sign that extends from the side of the building fronting on Main Street. Section 89-11 Table 1 page 1 of the Code of the Village/Town of Mt. Kisco states: Projecting signs are only permitted as an additional means of identifying the entrance of an establishment located in the Village Sign District without street frontage. **A variance will be required for this type of sign**.
- Section 89-11 Table 1 page 1 of the Code of the Village/Town of Mt. Kisco states Projecting Wall Signs maximum projection is three (3) feet (36 inches). The proposed projecting sign will project 40.5 inches. **A 4.5 inch variance will be required for the projection distance**.
- Section 89-11 Table 1 page 1 of the Code of the Village/Town of Mt. Kisco states: Projecting Wall Signs maximum size not to exceed 6 square feet. The proposed projecting sign is 6.99 square feet. **A .99 square foot variance will be required for the size of the sign.**

A sign permit cannot be issued for any sign application that does not comply with the Village Sign Code. You have a right to appeal this decision to the Zoning Board of Appeals within 60 days.

Sincerely,

Peter J. Miley
Building Inspector

/pat

The Ambleside Pub

23 East Main Street

Mount Kisco, NY 10549

Village/Town of Mount Kisco

Municipal Building

104 Main Street

Mount Kisco, NY 10549

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Zoning Board of Appeals
Village/Town of Mount Kisco

Attn: Zoning Board Members

I am writing to notify you of our intent to appeal the denial of our sign permit application. We have requested the application be scheduled for a public hearing on June 18, 2024.

Sincerely,

L Hodgson

Leigh Hodgson

Owner

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Zoning Board of Appeals
Village/Town of Mount Kisco

Date: ____________ Case No.: ____________

Fee: ____________ Date Filed: ____________

Village/Town of Mount Kisco
Municipal Building
104 Main Street, Mt. Kisco, NY 10549

Zoning Board of Appeals
Application

Appellant: Leigh Hodgson
Address: 38 Sands St, Mt. Kisco, NY 10549
Address of subject property (if different): 23 E. Main St., Mt. Kisco, NY 10549

Appellant's relationship to subject property: ____ Owner X Lessee ____ Other

Property owner (if different): The Beyem Company
Address: P.O. Box 305, New Rochelle, NY 10804

TO THE CHAIRMAN, ZONING BOARD OF APPEALS: An appeal is hereby taken from the decision of the Building Inspector, Peter Miley dated March 6, 2024 Application is hereby made for the following:

X Variation **or** ________ Interpretation of Section 89 of the Code of the Village/Town of Mount Kisco,

to permit the: X Erection; ____ Alteration; ____ Conversion; ____ Maintenance of double-sided projecting wall sign that extends from the side of the building fronting on Main St.
____________ in accordance with plans filed on (date) ____________
for Property ID # 69.81-2-5 located in the CB-1 Zoning District.
The subject premises is situated on the East side of (street) Main St.
____________ in the Village/Town of Mount Kisco, County of Westchester, NY.
Does property face on two different public streets? Yes/No
(If on two streets, give both street names) Main St. + S. Moger Ave.

Type of Variance sought: ~~X~~ Use X Area

Is the appellant before the Planning Board of the Village of Mount Kisco with regard to this property? Yes

Is there an approved site plan for this property? _______ in connection with a _____ Proposed or ______ Existing building; erected (yr.) _______________

Size of Lot: _______ feet wide ________ feet deep Area ____________

Size of Building: at street level ________ feet wide ____________ feet deep

Height of building: _________________ Present use of building: Food Establishment

Does this building contain a nonconforming use? NO Please identify and explain: ___

Is this building classified as a non-complying use? NO Please identify and explain: ___

Has any previous application or appeal been filed with this Board for these premises? Yes/No? __________

Was a variance ever granted for this property? _____ If so, please identify and explain:

Are there any violations pending against this property? NO If so, please identify and explain: ____________________

Has a Work Stop Order or Appearance Ticket been served relative to this matter? ___ Yes or √ No Date of Issue: __________________

Have you inquired of the Village Clerk whether there is a petition pending to change the subject zoning district or regulations? NO

I hereby depose & say that all the above statements and the statements contained in the papers submitted herewith are true.

Leigh Hodgson
(Appellant to sign here)

Sworn to before me this day of: May 23, 2024

MICHELLE K RUSSO
NOTARY PUBLIC-STATE OF NEW YORK
No. 01RU6313298
Qualified in Putnam County
My Commission Expires 10-20-2026

Notary Public. Michelle K. Russo, Westchester County, NY

[TO BE COMPLETED IF APPELLANT IS NOT THE PROPERTY OWNER IN FEE]

State of New York } Gerald Stern - Managing Partner, The Reyem Company LLC
County of Westchester } ss

Being duly sworn, deposes and say that he resides at 64 Wellington Avenue New Rochelle, NY 10804 in the County of Westchester, in the State of New York, that he is the owner in fee of all that certain lot, piece or parcel of land situated, lying and being in the Village of Mount Kisco, County of Westchester aforesaid and known and designated as number 23 E Main Street - Tax Map #: 555600 69.81-2-5 and that he hereby authorized Leigh Hodgson ~~The Ambleside Pub~~ to make the annexed application in his behalf and that the statements contained in said application are true.

Gerald Stern
(sign here)

Statement of Principal Points

(1) There will be no undesirable change produced in the character of the neighborhood or any detriment to nearby properties created by the granting of the variance.

  a. The sign will hang above the window to the left of the main entrance. It will be relatively small, with a length of 28" and a height of 36".
  b. No person nor properties will be hindered or obstructed by this variance.
  c. This type of quaint signage is appealing to potential customers visiting our town.

(2) The benefit sought cannot be achieved by a method other than a variance.

  a. As our location and main entrance is on the corner of Moger Street and Main Street, a flat sign above the door would be difficult to see while walking down either of those streets.
  b. The design of the door and clock above it do not provide adequate space for a reasonably-sized sign.

(3) The requested variance is substantial.

  a. A hanging blade sign is an integral, common component of traditional British pubs. This will add to the authenticity we are striving for with our establishment.
  b. This double-sided sign will enable potential customers to see the name of our establishment when walking down Main Street.

(4) The proposed variance will not have an adverse effect or impact on the physical or environmental conditions in the neighborhood or district.

  a. Blade signs are currently a recommendation to be included in the current DIG (Downtown Improvement Grant) whose primary focus is to beautify Mount Kisco.
  b. A double-sided, hanging blade sign will provide an aesthetic appearance to both our pub and to the town.

(5) The alleged difficulty was not self-created (this will not necessarily preclude the granting of the area variance).

  a. The design of the building and location of the door was created decades ago.

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Zoning Board of Appeals
Village/Town of Mount Kisco

AFFIDAVIT OF MAILING

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Zoning Board of Appeals
Village/Town of Mount Kisco

STATE OF NEW YORK }
}SS.:
COUNTY OF WESTCHESTER }

Leigh Hodgson being duly sworn, deposes and says:

I reside at 38 Sands St., Mt. Kisco, NY 10549

On May 20 2024 I served a notice of hearing, a copy of which is attached hereto and labeled Exhibit A, upon persons whose names are listed in a schedule of property owners within 300 feet of the subject property identified in this notice. A copy of this schedule of property owners' names is attached hereto and labeled Exhibit B. I placed a true copy of such notice in a postage paid property addressed wrapper addressed to the addresses set forth in Exhibit B, in a post office or official depository under the exclusive care and custody of the United States Post Office, within the County of Westchester.

Leigh Hodgson

Sworn to before me on this
23rd day of May 2024

Michelle K. Russo
(Notary Public)

MICHELLE K. RUSSO
NOTARY PUBLIC-STATE OF NEW YORK
No. 01RU6313298
Qualified in Putnam County
My Commission Expires 10-20-2026

RECEIVED

MAY 28 2024

Zoning Board of Appeals
Village/Town of Mount Kisco

PUBLIC NOTICE

PLEASE TAKE NOTICE that the Zoning Board of Appeals of the Village/Town of Mount Kisco, New York will hold a Public Hearing on the 18th day of June 2024 at the Municipal Building, Mount Kisco, New York, beginning at 7:00 PM pursuant to the Zoning Ordinance on the Appeal of

Leigh Hodgson – Owner, The Ambleside Pub

23 E. Main Street, Mount Kisco, NY 10549

from the decision of Peter J. Miley, Building Inspector, dated March 6, 2024 denying the application dated to permit the double-sided projecting wall sign that extends from the side of the building fronting on Main Street.

The property involved is known as The Ambleside Pub – 23 E. Main Street, Mount Kisco, NY 10549 and described on the Village Tax Map as Section 69.81 Block 2 Lot 5 and is located on the east side of Main Street in a CB-1 Zoning District. Said Appeal is being made to obtain a variance from Section(s) 89-11 of the Code of the Village/Town of Mount Kisco, which requires a variance.

Wayne Spector, Chair
Zoning Board of Appeals
Village/Town of Mount Kisco

OWNERNAME	PROPADDRESS	PROPCITY	PROPZIP	PROPPRINTKEY
Joule Realty LLC	19 Main St	MOUNT KISCO	10549	69.73-2-15
5 S Moger LLC	S Moger & Main St	MOUNT KISCO	10549	69.81-6-1
Verizon New York, Inc.	45 Main St	MOUNT KISCO	10549	69.81-2-3
55 Kisco LLC	55 Main St	MOUNT KISCO	10549	69.81-3-6
Masonic Guild	11 Carpenter Ave	MOUNT KISCO	10549	69.81-3-7
Village Of Mount Kisco	Kirby Plaza	MOUNT KISCO	10549	69.81-1-2
31-41 Main St LLC	Main St	MOUNT KISCO	10549	69.81-2-4
Village Of Mount Kisco	1 Main St	MOUNT KISCO	10549	69.73-2-20
Tsocanos, Anthony N	17 Main St	MOUNT KISCO	10549	69.73-2-16
Piazza, John S	23 Carpenter Ave	MOUNT KISCO	10549	69.81-3-1
Unknown, Owner	Quaker Pl	MOUNT KISCO	10549	69.81-2-8
Datahr Rehabilitation Inst.	38 Carpenter Ave	MOUNT KISCO	10549	69.81-2-2
HG Tribeca LLC	14 N Moger Ave	MOUNT KISCO	10549	69.73-2-14
People of the State of NY	Main St	MOUNT KISCO	10549	69.81-1-1
Howard G Kensing Jr Rev Trust	Kirby Plz	MOUNT KISCO	10549	69.81-1-6
EK Mt Kisco LLC	36 Main St	MOUNT KISCO	10549	69.81-6-2
De Patino, Blanca G. Espinoza	7- 9 N Moger Ave	MOUNT KISCO	10549	69.81-2-6
HG Tribeca LLC	3 Main St	MOUNT KISCO	10549	69.73-2-13
11 N Moger LLC	11 N Moger Ave	MOUNT KISCO	10549	69.81-2-7
19 North Moger Ave LLC	19 N Moger Ave	MOUNT KISCO	10549	69.81-2-1
South Moger LLC	12-18 S Moger Ave	MOUNT KISCO	10549	69.81-1-5
E & I Llc	7 Main St	MOUNT KISCO	10549	69.73-2-19
Tsocanos, Anthony N	15 Main St	MOUNT KISCO	10549	69.73-2-17
Rodmil Inc	21 S Moger Ave	MOUNT KISCO	10549	69.81-6-15
Larrlem LLC	15 S Moger Ave	MOUNT KISCO	10549	69.81-6-16
Mt Kisco Associates	38 Main St	MOUNT KISCO	10549	69.81-6-3
Village of Mount Kisco	Brook--S Moger	MOUNT KISCO	10549	69.81-6-4
The Chase Manhattan Bank	14 Main St	MOUNT KISCO	10549	69.81-1-3
Moses Taylor Jr Post 136	19 Jeff Feigel Sq	MOUNT KISCO	10549	69.81-3-4
Fustini Stephanie N	10 S Moger Ave	MOUNT KISCO	10549	69.81-1-4
Shthead llc	11 Main St	MOUNT KISCO	10549	69.73-2-18
The Reyem Company LLC	Main St	MOUNT KISCO	10549	69.81-2-5
2427 Webster Associates LLC	33 N Moger Ave	MOUNT KISCO	10549	69.73-3-11

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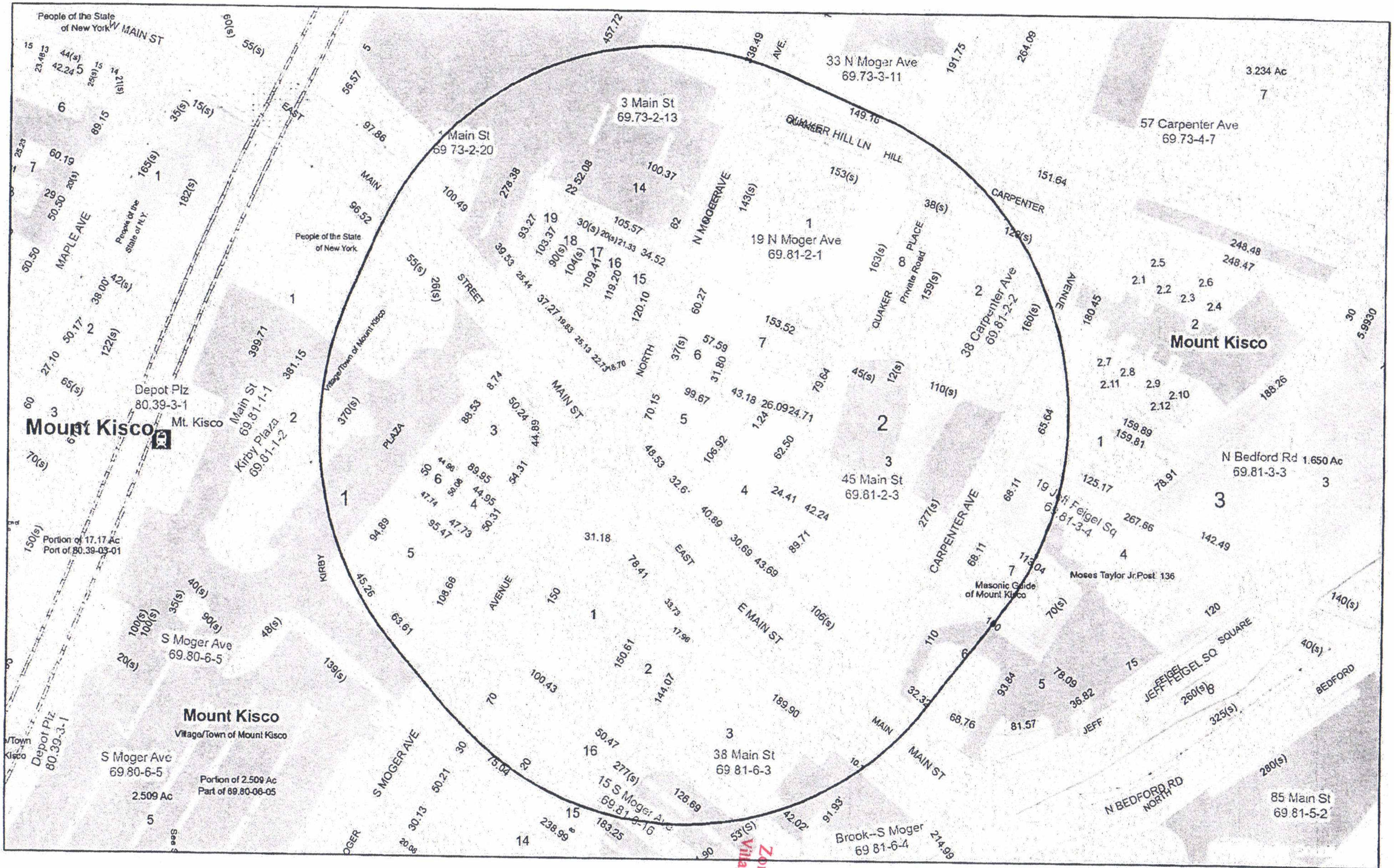
Zoning Board of Appeals
Village/Town of Mount Kisco

C/O	Mailing Address	City	State	Zip
Lawrence Freidland - Larstrand Corp	500 Park Avenue, 11th Floor	NY	NY	10022
Duff & Phelps	PO Box 2749	Addison	TX	75001
Larstand Corp	500 Park Avenue, 11th Floor	NY	NY	10022
Robin Traina - President	264 D Heritage Hills	Somers	NY	10589
	104 Main Street	Mt. Kisco	NY	10549
Allen Resnick	269-10 Grand Central Pkwy #17 B	Floral Park	NY	11005
	104 Main Street	Mt. Kisco	NY	10549
Kanta Asrani	19 E Main Street	Mt. Kisco	NY	10549
VACANT LAND	No owner address			
Ability & Beyond Disability	5 Berkshire Blvd	Bethel	CT	06810
Brian Breye	111 Murray St, West Unit 29	New York	NY	10007
Dir Real Estate Westchester Cty	148 Martine Avenue, 9th Floor	White Plains	NY	10601
	45 Washburn St	Mt. Kisco	NY	10549
Adam Brodsky	3 West 57th Street 7th Floor	New York	NY	10019
	91 Grove Street	Mt. Kisco	NY	10549
Brian Breye	111 Murray St, W Unit 29	New York	NY	10007
	19 N Moger Ave	Mt. Kisco	NY	10549
Larstand Corp	500 Park Avenue, 11th Floor	NY	NY	10022
Bicycle World	7 E Main Street	Mt Kisco	NY	10549
CRK Group LLC Chandon Asranti	19 E Main Street	Mt. Kisco	NY	10549
Kevin Hitson, Warshaw Burstein LLC	575 Lexington Avenue	New York	NY	10022
Larstand Corp	500 Park Avenue, 11th Floor	NY	NY	10022
Love Realty	Gedney Station, PO Box 28	White Plains	NY	10605
	104 Main Street	Mt. Kisco	NY	10549
	5 Chestnut Ridge Rd	Mt. Kisco	NY	10549
Robert Bernstein	Mt. Kisco Sports, 13 E main Street	Mt. Kisco	NY	10549
NA				
	825 East 233rd Street	Bronx	NY	10466

Main St. ID: 69.81-2-5 (Mount Kisco)



May 6, 2024

Tax parcel data was provided by local municipality. This map is generated as a public service to Westchester County residents for general information and planning purposes only, and should not be relied upon as a sole informational source. The County of Westchester hereby disclaims any liability from the use of this GIS mapping system by any person or entity. Tax parcel boundaries represent approximate property line location and should NOT be interpreted as or used in lieu of a survey or property boundary description. Property descriptions must be obtained from surveys or deeds. For more information please contact local municipality assessor's office.

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MAY 28 2024
Zoning Board of Appeals
Village/Town of Mount Kisco

1:1,500

N

0 70 140 280 ft

Westchester County GIS

http://giswww.westchestergov.com
Michaelian Office Building
148 Martine Avenue Rm 214
White Plains, New York 10601

10161045, 1442894

AFFIDAVIT OF PUBLICATION

State of Wisconsin
County of Brown

Linda Tutt being duly sworn, deposes and says she is the Principal Clerk of **The Journal News**, Division of Gannett Newspaper Subsidiary, publishers of following newspaper published in Westchester and Rockland Counties, State of New York, of which annexed is a printed copy, out from said newspaper has been published in said newspaper editions dated:

05/10/2024

Linda Tutt

Subscribed and sworn to before me this 10 day of May, 2024

Keegan Moran
exp. 2.14.28

Notary Public
State of Wisconsin, County of Brown

KEEGAN MORAN
Notary Public
State of Wisconsin

RECEIVED

JUN 11 2024

Zoning Board of Appeals
Village/Town of Mount Kisco

State of New York)
) ss:
County of Westchester)

AFFIDAVIT OF POSTING

Gilmar Palacios Chin, being duly sworn, says that on the 11th day of June 2024, he conspicuously fastened up and posted in seven public places, in the Village/Town of Mount Kisco, County of Westchester, a printed notice of which the annexed is a true copy, to Wit: ---

Municipal Building – 104 Main Street	X
Public Library 100 Main Street	X
Fox Center	X
Justice Court – Green Street 40 Green Street	X
Mt. Kisco Ambulance Corp 310 Lexington Ave	X
Carpenter Avenue Community House 200 Carpenter Avenue	X
Leonard Park Multi Purpose Bldg	X

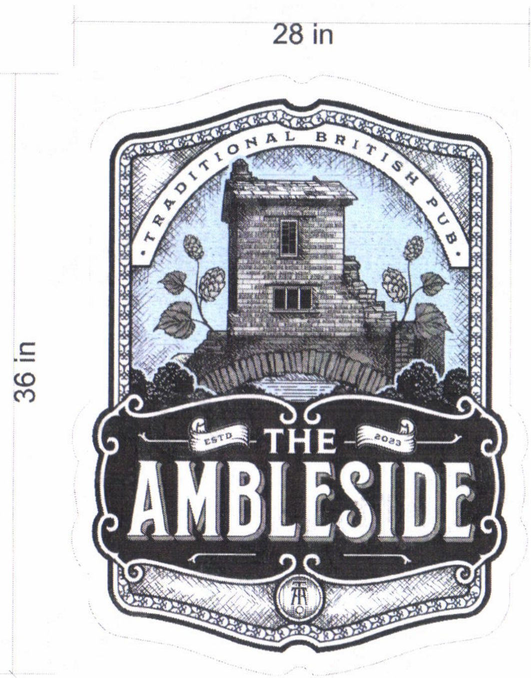
Gilmar Palacios Chin

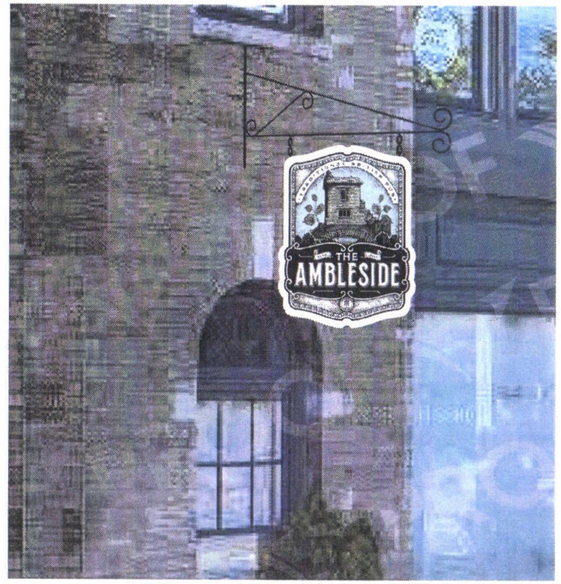
Sworn to before me this 11th day of June 2024

Michelle K. Russo
Notary Public

MICHELLE K. RUSSO
NOTARY PUBLIC-STATE OF NEW YORK
No. 01RU6313298
Qualified in Putnam County
My Commission Expires 10-20-2026

DATE/TIME/PROOF	JOB/PROJECT	
1/9/2024 2:15pm	The Ambleside Pub	5 Schuman Road, Millwood, New York 10546 Phone: 914-666-7446 Email: info@signarama-millwood.com www.Signarama-Millwood.com
Rev3		Signarama Millwood
INV4118 - Hanging PVC		





NOTES

DOUBLE SIDED

LAW OFFICES OF
SNYDER & SNYDER, LLP
94 WHITE PLAINS ROAD
TARRYTOWN, NEW YORK 10591
(914) 333-0700
FAX (914) 333-0743

WRITER'S E-MAIL ADDRESS

rgaudioso@snyderlaw.net

NEW YORK OFFICE
445 PARK AVENUE, 9TH FLOOR
NEW YORK, NEW YORK 10022
(212) 749-1448
FAX (212) 932-2693

LESLIE J. SNYDER
ROBERT D. GAUDIOSO (NY/NJ)
DOUGLAS W. WARDEN
JORDAN M. FRY
MICHAEL SHERIDAN (NY/NJ)
DAVID KENNY (NY/NJ)

DAVID L. SNYDER
(1956-2012)

NEW JERSEY OFFICE
ONE GATEWAY CENTER, SUITE 2600
NEWARK, NEW JERSEY 07102
(973) 824-9772
FAX (973) 824-9774

REPLY TO:

TARRYTOWN OFFICE

June 7, 2024

Honorable Chairman Wayne Spector
and Members of the Zoning Board of Appeals
Village of Mount Kisco
104 Main Street
Mount Kisco, New York 10549

Re: 333 North Bedford Road ("Property")
Public Utility Battery Energy Storage Facility
New Leaf Energy

Honorable Chairman Spector and
Members of the Zoning Board of Appeals:

We are the attorneys for New Leaf Energy ("New Leaf" or "Applicant") in connection with its application to develop a public utility battery energy storage facility ("Facility") at the above captioned site. For the following reasons, the proposed Facility is a public utility facility as defined under the Village of Mount Kisco Code, and is regulated for zoning purposes pursuant to the New York public utility zoning standard.

As we have discussed, the Facility is necessary to integrate renewable energy sources into the grid while also maintaining grid stability, and provide firm energy output during periods of peak usage, which prevents system outages during extreme weather conditions.

New York State has passed the nation-leading Climate Leadership and Community Protection Act ("Climate Act"), which codified the state's aggressive energy and climate goals. These goals include rapid deployment of solar and offshore wind generation in order to meet a 70% renewable energy by 2030 goal and 100% carbon-free electricity by 2040 goal. Battery energy storage will play a crucial role in meeting these ambitious goals. Battery energy storage will help to integrate clean energy into the grid, reduce costs associated with meeting peak electric demands, and increase efficiency. Additionally, battery energy storage can stabilize supply during peak electric usage to avoid blackouts or costly damage to the grid. For this reason, the Climate Act includes a 3,000 MW of energy storage by 2030 goal, which was further increased by Governor Kathy Hochul to 6,000 MW of Energy Storage by 2030.

As detailed below, the State's energy goals, including the implementation of Battery Energy Storage Systems, have been implemented through a series of Orders issued by the New York State Public Service Commission ("PSC"). The PSC was established under State Public Service Law, Article 1, Section 4, and is responsible for regulating the state's electric, gas, steam, telecommunications, and water utilities, and overseeing the cable industry. The Commission is charged by law with setting rates and ensuring New York's utilities provide adequate service.

Battery Energy Storage Systems, such as the Facility, are considered Distributed Energy Resources and are integral components of the public utility electric grid. Such systems must be approved by the distribution electricity provider, in this case Con Edison, necessary to support the electric grid. Before an interconnection agreement can be executed between a Facility and Con Edison to allow the Battery Energy Storage System to interconnect, a full study is performed following a PSC regulated process. Compensation for the electricity supplied to the grid from the Battery Energy Storage System is regulated by a PSC tariff known as the Value Stack. Distributed Energy Resources, which include stand-alone Battery Energy Storage Systems such as the Facility, require significant investment to develop. However, such facilities are cleaner for the environment and cheaper to integrate into the grid than the construction of new fossil fuel facilities.

In other words and simply put, New York State recognized the need to change the status-quo of electricity generation to make way for renewables. Private investment is a core component of this transition. The PSC, as the State regulatory agency, created a mechanism for distribution utility review and regulation of private interconnections (known as SIR/CESIR as described in detail below), and a compensation program (known as VDER and described below). Battery Energy Storage Systems, such as the Facility, are necessary for the State to reach its renewable energy goals and for the grid to be safe and reliable.

I. <u>The Mount Kisco Code</u>

Throughout the Village of Mount Kisco Code, the Village Board has clearly expressed the importance and preference of energy efficiency and distributed energy resources, including battery storage, consistent with the requirements of New York State and the local electricity supplier, Con Edison.

For example, Section 100-1(A) of the Village Code, entitled: "Legislative findings; intent and purpose; authority", states:

> **<u>It is the policy of both the Village/Town of Mount Kisco and the State of New York</u>** to reduce costs and provide cost certainty for the purpose of economic development, **<u>to promote deeper penetration of energy</u>**

> **efficiency and renewable energy resources such as wind and solar, and wider deployment of distributed energy resources** as well as to examine the retail energy markets and increase participation of and benefits for eligible customers in those markets. Among the policies and mode's that may offer benefits in New York is community choice aggregation ("CCA"), which allows local governments to procure electric and natural gas supply on behalf of its eligible customers. (Emphasis supplied).

Likewise, Section 110-32.2(B) of the Village Code, entitled "Solar energy", states:

> Statement of purpose. This solar energy section is adopted to advance and protect the public health, safety, and welfare of the people of the Village by creating regulations for the installation and use of solar energy generating systems and equipment, with the following objectives:
> (1) To take advantage of a safe, abundant, renewable and nonpolluting energy resource;
> (2) To decrease the cost of electricity to the owners of residential and commercial properties, including single-family houses;
> (3) To increase employment and business development in the Village, to the extent reasonably practical, by furthering the installation of solar energy systems;
> (4) To mitigate the impacts of solar energy systems on environmental resources such as forests, wildlife and other protected resources;
> (5) To create synergy between solar and the stated goals of the community pursuant to its Comprehensive Plan, such as the protection of environmental resources, **assuring that community services sufficiently meet the needs of the Village's current and future population**, and promote a balanced pattern of future land use;
> (6) **To invest in a locally generated source of energy and to increase local economic value, rather than importing nonlocal fossil fuels**;
> (7) **To align the laws and regulations of the community with several policies of the State of New York, particularly those that encourage distributed energy systems**;
> (8) **To diversify energy resources to decrease dependence on the grid**;
> (9) To make the community more resilient during storm events; and
> (10) To encourage investment in public infrastructure supportive of solar, **such as generation facilities, grid-scale transmission infrastructure, and energy storage sites.** (Emphasis supplied).

The Village Board's stated goal of promoting distributed energy systems, including Battery Energy Storage Systems, consistent with the policies of the State of New York are rooted in the laws of the State and the Orders of the PSC as detailed below.

II. New York State Policies, Goals and PSC Orders

Battery Energy Storage Systems are considered key distributed energy systems. The installation of Battery Energy Storage Systems are an essential element of the Village Board's goal as set forth in Section 110-32.2(B)(7) to "align the laws and regulations of the community with several policies of the State of New York, particularly those that encourage distributed energy systems."

New York State has created policies and goals to encourage distributed energy systems, particularly Battery Energy Storage Systems.

Consistent with New York State's goals, the PSC has issued a number of critical Orders. On February 26, 2015, the PSC issued an Order entitled "Order Adopting Regulatory Policy Framework and Implementation Plan, Case 14-m-0101 regarding the Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV Order"), a copy of which is attached hereto as Exhibit 2. The REV Order was intended to prepare the grid for the future state of renewable energy and reliability. The REV Order laid the groundwork to have distributed energy generation that is privately owned and on smaller scale, which means that the energy provided by such facilities, including Battery Energy Storage Systems, must be appropriately compensated in order for the market to attract investment.

On the heels of the REV Order, on March 9, 2017, the PSC issued an Order entitled "Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matter" based on case 15-E-0751, In the Matter of the Value of Distributed Energy Resources ("VDER Order"), a copy of which is attached hereto as Exhibit 3. The VDER Order developed the Value of Distributed Energy Resources ("VDER") resulting in the Value Stack. The Value Stack was developed through a rigorous process to compensate private owners for providing distributed energy (like energy storage) to the grid. This includes revenues for the value they contribute, like adding energy to the grid during peak times, avoiding utility distribution investment, and making the grid more stable and reliable.

The Value Stack is now a rate class within each utility's tariff. Any distributed energy resource, including Battery Energy Storage Systems, with an interconnection agreement with the utility can receive the Value Stack compensation if they provide energy during the windows that the Value Stack compensates for. Attached hereto as Exhibit 4 is a NYSERDA pamphlet which explains the Value Stack in more detail. A copy of the Con Edison, Rider R, Net Metering and

Value Stack Tariff for Customer-Generators, is attached hereto as Exhibit 5.

In order to obtain an interconnection, a developer submits an application to the utility. The application then follows the "SIR process". The SIR process is how the utility evaluates whether the facility meets the interconnection standards and determines the cost of the interconnection (which the developer must pay). That process results in a CESIR study result. See PSC Order entitled "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in parallel with Utility Distribution Systems" ("Interconnection Order"), a copy of which is attached here as Exhibit 6.

As detailed below, the New Leaf Facility has followed the PSC process and Con Edison has approved the Facility for interconnection necessary to provide electricity to the grid in Mount Kisco.

III. <u>Con Edison Interconnection</u>

Recognizing the need and value of Distributed Energy Resources, including Battery Energy Storage systems, Con Edison has developed its own Battery Energy Storage Systems and has entered into interconnection agreements with developers such as New Leaf. Attached hereto as Exhibit 7 is a Con Edison article detailing the need for Battery Energy Storage Systems, Con Ed's development of such systems and the fact that Con Edison has issued a Request for Proposal for the interconnection of Battery Energy Storage Systems, such as the Facility, that can go into operation by the end of 2025.

Con Edison determines the areas of need so that developers of distributed energy resources, including Battery Energy Storage Systems, can interconnect to the electricity grid to serve the electricity needs. As noted above, the location of the Facility is based on Con Edison's feeder lines as detailed in the Con Edison Hosting Capacity Map attached as Exhibit 1.

Likewise, the energy to be produced by the Facility and provided to the grid is based on the demand, as communicated by Con Edison. Attached as Exhibit 8 is the Con Edison Demand Response Program, Commercial System Relief Program ("CSRP"), Event Call Window schedule for 2024, which includes the Mount Kisco area and the requirements for the proposed Facility. "Customers participating in CSRP will be asked to reduce their energy use during a four-hour long call window period, which generally corresponds to the network's peak loading period." The Facility is intended to provide needed electricity during that specific call time.

Here, Con Edison performed a detailed study to determine the feasibility and necessity of the proposed Facility. Attached hereto as Exhibit 9 is the Con Edison Coordinated Electric System Impact Review ("CESIR") that was performed and was required for the interconnection of the Facility into the grid. The CESIR presents the analysis results of the interconnection study performed by Con Edison in accordance with Con Edison's engineering standards. It assesses the Facility's feasibility, determines its impact on the existing grid, determines the interconnection scope and installation reequipments, and determines the costs to New Leaf to interconnect the Facility.

Based on the successful completion of the CESIR feasibility study, New Leaf and Con Edison entered into the New York State Standardized Interconnection Agreement attached hereto as Exhibit 10.

Based on the foregoing, the Facility is necessary to provide safe and adequate electricity to the grid.

IV. Mount Kisco Code Definition

The Property is located in the Light Manufacturing District. Pursuant to the Village/Town of Mount Kisco Zoning Code ("Zoning Code"), "public utilities" are permitted principal uses in the Light Manufacturing District. "Public utilities" are not a permitted principal use in any other Zoning District. In fact, the Light Manufacturing District is located in only one small area in the corner of the Village. See Zoning Map with location of the Property highlighted, attached hereto as Exhibit 11.

Section 110-59 defines a "public utility facility" for purposes of the Zoning Code as follows:

> "A facility other than a personal wireless service facility for the provision of public utility services, including facilities constructed, altered or maintained by utility corporations, either public or privately owned, or government agencies, necessary for the provision of electricity, gas, steam, heat, communication, water, sewage collection or other such service to the general public. Such facilities shall include poles, wires, mains, drains, sewers, pipes, conduits, cables, alarms and call boxes and other similar equipment, but shall not include office or administration buildings. For purposes of this chapter, personal wireless service facilities, defined separately in this chapter, shall not be governed by the zoning regulations which apply to the broader definition of public utility facilities, but shall be governed by the regulations of the Personal Wireless Services Facilities Overlay District which specifically regulates this category of public utilities."

The foregoing definition establishes the following factors:

1. "A facility other than a personal wireless service facility for the provision of public utility services . . ."

    - The Facility is not a personal wireless service facility.

    - The Facility provides electricity to the grid. Electricity is a public utility service. The generation and distribution of electricity has long been held to be a public utility use. *See* "Zoning and the Expanding Public Utility," 13 Syracuse L. Rev. 581 (1962). Such uses are generally accorded special treatment under local zoning authority. *See Consolidated Edison Co. of N.Y., Inc. v. Hoffman*, 43 N.Y.2d 598 (1978); *see also* Salkin, New York Zoning Law and Practice, 4th Ed. Section 11:18.

2. " . . . including facilities constructed, altered or maintained by utility corporations, either public or privately owned, or government agencies. . . ."

    - The definition does not require that this factor be satisfied as it expressly states, "including facilities . . . .".
    - In any event the Applicant is a privately owned company. For purposes of electric generation and supply in New York, there is no meaningful distinction between a private or public entity which is a utility. *See Cellular Telephone Co. v. Rosenberg*, 82 N.Y.2d 364, 371 (1993) (stating that "a public utility has been defined to mean a private business...," and that characteristics of public utilities include the essential nature of the services offered). Con Edison is an investor-owned business.

3. ". . . .necessary for the provision of electricity, gas, steam, heat, communication, water, sewage collection or other such service to the general public."

    - As detailed at length above, the Facility is necessary for the provision of electricity.

    - The proposed Facility is necessary to support the utility grid, currently scheduled during the daytime hours of 2:00 am to 6:00 pm. This 4-hour window was identified by Con Edison as the time of highest strain on the grid and the Facility will help to avoid the risk of blackouts in the area. In particular, the Facility will be connected to support the branch (called "feeder") marked in yellow, green and blue in the image attached hereto as Exhibit 1. This feeder provides all of the electricity to north Mount Kisco, east of the Metro North railroad. Thus, the Facility is necessary to support the provision of electricity in Mount Kisco.

4. "Such facilities shall include poles, wires, mains, drains, sewers, pipes, conduits, cables, alarms and call boxes and other similar equipment, but shall not include office or administration buildings."

    - The Facility includes wires, conduits, and other similar equipment.
    - The Facility does not include office or administration buildings, being the only structures expressly eliminated from the definition.

5. "For purposes of this chapter, personal wireless service facilities, defined separately in this chapter, shall not be governed by the zoning regulations which apply to the broader definition of public utility facilities, but shall be governed by the regulations of the Personal Wireless Services Facilities Overlay District which specifically regulates this category of public utilities."

    - The Facility is not a personal wireless service facility.

For all the foregoing reasons, it is respectfully submitted that the Battery Energy Storage Facility is a permitted "public utility facility" use on the Property under Sections 110-24 and 110-59 of the Zoning Code, subject to site plan approval and a wetlands permit from the Planning Board, and any necessary area variances from the Zoning Board.

Under New York State case law, any ambiguity in a local zoning code compels a favorable determination for the applicant. In *Matter of Allen v. Adami*, the New York State Court of Appeals held that "[s]ince zoning regulations are in derogation of the common law, they must be strictly construed against the municipality which has enacted and seeks to enforce them" and "[a]ny ambiguity in the language used in such regulations must be resolved in favor of the property owner." *Adami*, 39 N.Y.2d 275, 277 (1976). The principle of law established in *Adami* therefore leaves no doubt that the Facility is a "public utility" as defined in §110-59 of the Zoning Code.

We thank you for your consideration and look forward to discussing this matter with the Zoning Board of Appeals at the June 18, 2024 continued public hearing.

If you have any questions or require any additional documents, please do not hesitate to contact me at 914-333-0700.

Snyder & Snyder, LLP

By: ______________________
Robert D. Gaudioso

Exhibits
RDG/cae
cc: New Leaf Energy
Peter Miley, Building Inspector (by email)
Z:\SSDATA\WPDATA\SS3\RDG\New Leaf Energy\Mount Kisco\ZBA Filing 04.26.2024\ZBA Letter 05.25.2024.rtf

Exhibit 1

Source: Con Edison's Hosting Capacity Map

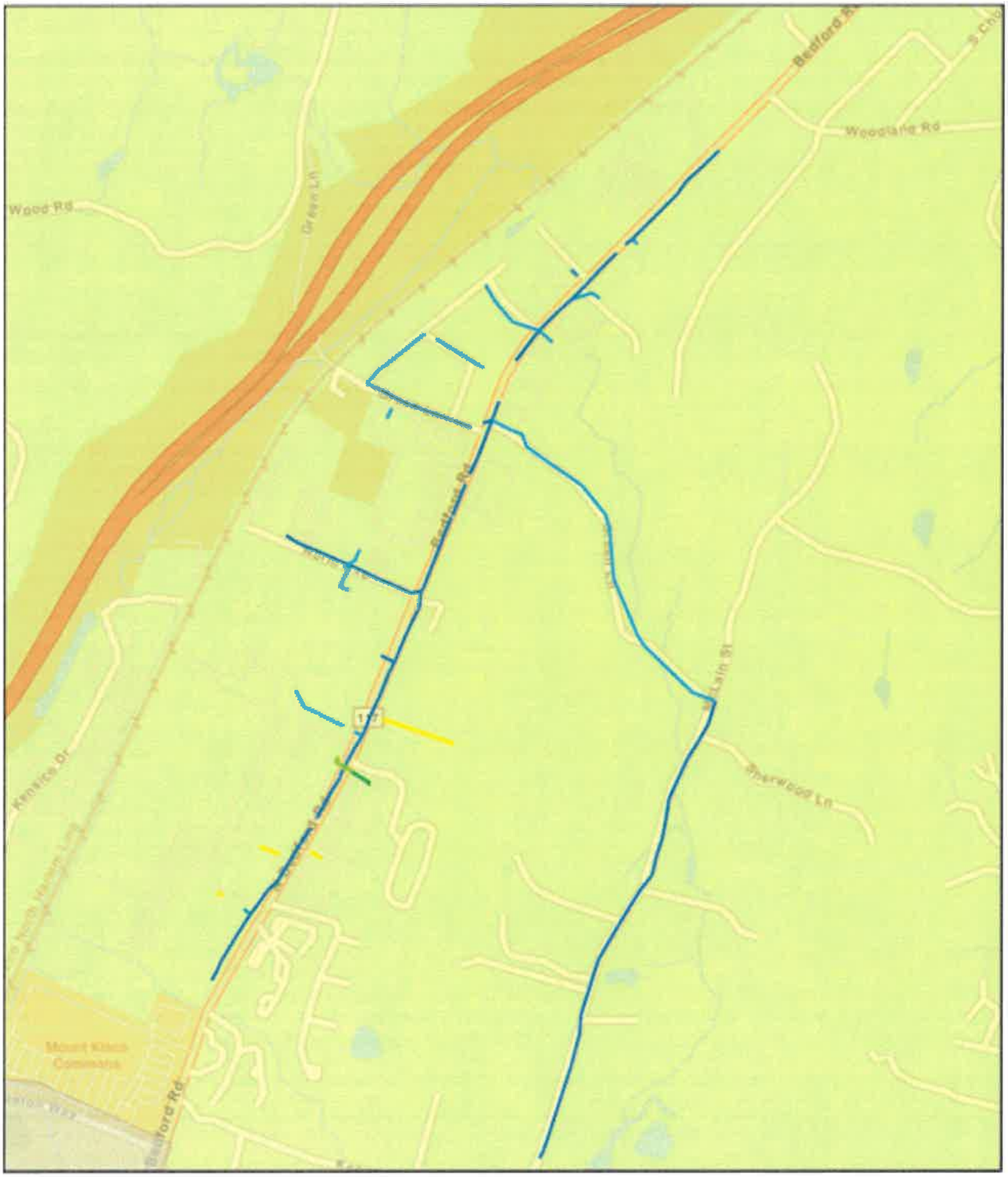

Bedford Rd
Woodland Rd
Wood Rd
Green Ln
117
Kensico Dr
Sherwood Ln
Mount Kisco Commons
Bedford Rd

Exhibit 2

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

ORDER ADOPTING REGULATORY POLICY FRAMEWORK AND IMPLEMENTATION PLAN

Issued and Effective: February 26, 2015

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on February 26, 2015

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Patricia L. Acampora
Gregg C. Sayre

COMMISSIONER EXCUSED:

Diane X. Burman

CASE 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

ORDER ADOPTING REGULATORY POLICY FRAMEWORK AND IMPLEMENTATION PLAN

(Issued and Effective February 26, 2015)

BY THE COMMISSION:

I. INTRODUCTION

The electric industry is in a period of momentous change. The innovative potential of the digital economy has not yet been accommodated within the electric distribution system. Information technology, electronic controls, distributed generation, and energy storage are advancing faster than the ability of utilities and regulators to adopt them, or to adapt to them. At the same time, electricity demands of the digital economy are increasingly expressed in terms of reliability, choice, value, and security.

Cost, as always, is a driving concern. Aging infrastructure, declining system efficiency, and flat sales growth place pressure on rates, and imply increases under a business-as-usual approach. Meanwhile, the trend toward affordability of self-generation threatens to create an unacceptable gap between those who can choose to leave the grid and those who cannot, with implications for the obligation to ensure reasonably priced and reliable service.

Climate change also compels reform. Forward planning in the electric industry must include carbon reduction, building to withstand severe weather, and dynamic system management to accommodate the needs of a low-carbon generation fleet.

The State of New York is responding to these challenges. Governor Andrew Cuomo's 2015 State of the State address documented the substantial efforts underway in New York, which are "reforming the energy vision" for the State, many of which are actions taken by this Commission. They include the creation of the nation's largest Green Bank, the launch of the NY-Sun solar initiative, the multi-agency Charge NY initiative to support electric vehicle deployment, BuildSmart NY to retrofit public buildings across the State, and the multi-state Regional Greenhouse Gas Initiative.[1] Following Superstorm Sandy, billions of dollars are being invested to harden infrastructure, including by utilities, to prepare for the increasing frequency of severe storms. In 2014, the Legislature passed, and Governor Cuomo enacted, the Community Risk and Resiliency Act to strengthen New York State's preparedness for the effects of climate change.[2]

While much has been accomplished in recent years, the Commission's mandate to ensure safe and adequate service at just and reasonable rates, coupled with the statutory charge to promote efficient planning and use of resources, compels further regulatory action to secure fulfillment of the State's energy needs. The challenges that stimulate action also reveal tremendous opportunities to improve our century-old regulatory system. The regulatory initiative launched in this proceeding, Reforming the

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[1] Governor Andrew M. Cuomo, 2015 Opportunity Agenda, State of the State, pages 131-153.

[2] Chapter 355 of the Laws of 2014.

Energy Vision (REV), aims to reorient both the electric industry and the ratemaking paradigm toward a consumer-centered approach that harnesses technology and markets. Distributed energy resources (DER)[3] will be integrated into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system.

This new direction is consistent with the 2014 Draft State Energy Plan, which calls for the use of markets and reformed regulatory techniques to achieve increased system efficiency, carbon reductions, and customer empowerment.[4] The reforms and innovation that are contemplated in this proceeding will be done in conjunction with the independent but related actions of the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (NYPA), the Long Island Power Authority (LIPA) and the New York Independent System Operator (NYISO), with the overall objective of ensuring that New York meets and exceeds its targeted goals to reduce carbon emissions through energy efficiency and clean power development in a manner that ensures grid reliability and resiliency while enhancing the value of the system for consumers.

The goals of REV are ambitious. However, the extent of party activity and widespread support for the objectives of this proceeding indicate that the industry and the public are ready to meet this challenge. The Commission will not be alone in the design and development of the reformed electric system. This will occur over a period of years through the mutual efforts of industry, customers, non-governmental advocates, and regulatory partners.

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3 Throughout this order, "DER" is used to describe a wide variety of distributed energy resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities.

4 Shaping the Future of Energy, New York State Energy Planning Board, 2014.

In this Order, we adopt a policy framework for a reformed retail electric industry. We decide those issues that need resolution at this stage, discuss numerous issues that need further development, and specify a process for moving forward. A companion to this Order, under Track Two of this initial phase of REV, will adopt ratemaking reforms to secure equitable allocation of benefits and costs among customers and to align utilities' financial interests with the objectives of reform.

II. PUBLIC PROCESS AND COMMISSION AUTHORITY

Prior to the institution of this proceeding, we directed New York State Department of Public Service Staff (Staff) to begin a process to reconsider our regulatory paradigms and markets.[5] After a period of inquiry and a Staff Report and Proposal,[6] we issued an Order Instituting Proceeding on April 25, 2014.[7] Our Order stated six objectives for the current initiative:

- Enhanced customer knowledge and tools that will support effective management of the total energy bill;
- Market animation and leverage of customer contributions;
- System wide efficiency;
- Fuel and resource diversity;
- System reliability and resiliency; and
- Reduction of carbon emissions.

Building on the Commission's guidance, Staff has articulated the REV vision in two documents. The April 24, 2014 Staff Report and Proposal formed the basis

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[5] Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard, Order Approving EEPS Program Changes, issued December 26, 2013.

[6] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, DPS Staff Report and Proposal, April 24, 2014.

[7] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014).

for the initiation of this proceeding.[8] The proceeding was separated into two tracks, with Track One focused on developing distributed resource markets, and Track Two focused on reforming utility ratemaking practices. On August 22, Staff issued a Straw Proposal for Track One which, in addition to party comments and further refinements identified here, articulates the basis for this policy decision.[9]

In the period between the Staff Report and the Straw Proposal, parties engaged in collaborative efforts and offered informal guidance on major policy issues. Nearly three hundred parties participated in these efforts. Under the leadership of two Administrative Law Judges, the parties formed two working groups charged with gathering data that broke into five committees (Markets; Customer Engagement; Platform Technology; Microgrids; and Wholesale Markets). The working groups filed reports on July 8, 2014 and presented their results in a July 10, 2014 technical conference before the Commission. Parties were also invited to submit preliminary comments on a number of policy issues, to guide the development of Staff's proposal, and 68 comments were submitted on July 18, 2014.[10]

Following the issuance of the Straw Proposal, a Notice of Proposed Rulemaking was published in the State Register on September 10, 2014, pursuant to the State Administrative Procedure Act.[11] Eighty-one initial comments were filed on September 22, 2014 and thirty-seven replies on October 24, 2014. Due to the volume of party comments, it is not feasible to summarize all party comments within the text of this Order. Comments are summarized by interest group, and individual comments are cited

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8 The extensive bibliography attached to the Staff Report illustrates the extent of Staff's research and the level of work on these issues that has already been undertaken among thought leaders in the electric industry.

9 Staff will issue a straw proposal on Track Two issues by June 1, 2015.

10 Parties were also invited to submit preliminary comments on Track Two ratemaking issues, which were received on July 18, 2014.

11 SAPA 14-M-0101SP8.

as either representative or particularly applicable. A summary of key topics addressed in party comments filed in response to the Straw Proposal is attached as Appendix A.

A second technical conference was held on November 6, 2014, in which policy issues were discussed among parties and Commissioners.

On October 24, 2014, the Commission issued the Draft Generic Environmental Impact Statement for comment. Fifteen comments were received, and on February 6, 2015 the Commission adopted the Final Generic Environmental Impact Statement. A Findings Statement prepared by the Commission as lead agency in this action in accordance with the State Environmental Quality Review Act, is attached to this Order as Appendix B.

In addition to party comments, over one thousand public comments have been filed on the Commission website.[12] The majority of these comments express general support for the REV concept, but identify various concerns. Comments covered a broad range of topics, including climate change, renewable resources, energy efficiency programs, net metering, the need for customer protections, and concerns about the speed and accessibility of the REV process.

The Commission also conducted public statement hearings in Buffalo, Syracuse, Albany, Kingston, Binghamton, Rochester, Yonkers, and New York City. Each hearing was preceded by an information session. Statewide, over 750 people attended the hearings and 240 individuals made statements. A large majority of speakers were supportive of REV goals to deploy greater distributed energy resources, energy efficiency, and renewable energy generation, addressing climate change and advocating that the Commission set benchmarks to wean New York off nuclear and all fossil fuels in the near future. Individuals also addressed the future of net metering, requested that incentive programs for renewable deployment be expanded, and discussed the benefits of geothermal technologies. Many speakers expressed concern that REV could increase the

[12] Over six hundred commenters were affiliated with Environmental Advocates and over one hundred commenters were affiliated with People United for Sustainable Housing.

role and power of utilities, to the detriment of customers. Speakers called for greater transparency and oversight to protect customers. Many speakers also addressed the need for more public outreach, energy education, and increased opportunities for public involvement. Strong support was voiced for community based organizations that could enable customers to manage their energy use and cost. Concerns were expressed for low income communities, including the impact of the costs of implementing REV and the need to ensure that benefits of REV accrue to low income and environmental justice communities. In several hearings, individuals expressed apprehension about the health impacts of installing smart meters in homes.

A large number of participants in the public statement hearings argued for increased spending on renewable generation. Staff noted in its Straw Proposal that this issue might best be addressed on a separate procedural track. The procurement of grid-scale renewables will not be resolved in this order; rather, a separate process is established as discussed below in the Implementation section.

This proceeding is in continuity with numerous Commission actions that have been undertaken in recent years. These include: the Competitive Opportunities proceeding in which competitive electricity markets were first established in New York;[13] the Renewable Portfolio Standard (RPS) and Energy Efficiency Portfolio Standard (EEPS) proceedings in which clean energy and efficiency targets, and the means to achieve them, were established;[14] a series of proceedings establishing a regulatory

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[13] Case 94-E-0952, et al, In the Matter of Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service, issued May 20, 1996.

[14] Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard; Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard.

framework for distributed generation;[15] inquiries into smart meters and smart grid systems;[16] and new directions related to distribution infrastructure established in the most recently decided Consolidated Edison rate case.[17]

Pursuant to Public Service Law Section 65(1), the Commission is responsible for ensuring that electric corporations "furnish and provide such service, instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable." PSL Section 5(2) further requires that the Commission "encourage persons and corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

The Commission has the responsibility to adjust its regulatory framework in response to evolving circumstances and foreseeable trends, in order to meet customers' needs. These adjustments may include innovative, market-based tools and the formation of new business models. In 1996, the Commission directed New York's investor-owned electric utilities to develop and file proposed plans for restructuring to introduce

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[15] Case 99-E-1470, Proceeding on Motion of the Commission to Initiate an Inquiry into the Reasonableness of the Rates, Terms and Conditions for the Provision of Electric Standby Service; Case 02-M-0515, Establish Gas Transportation Rates for Distributed Generation Technologies; New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems.

[16] Case 09-M-0074, In the Matter of Advanced Metering Infrastructure; Case 10-E-0285, Proceeding on Motion of the Commission to Consider Regulatory Policies Regarding Smart Grid Systems and the Modernization of the Electric Grid.

[17] Case 13-E-0030, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal, issued February 21, 2014.

competition.[18] This action was held to be consistent with the Public Service Law[19] and supported by determinations in the Appellate Division that the Commission's authority extended to a decision to "introduce 'competition into a monopolistic marketplace and thus lower prices to consumers,'"[20] and that it was entirely appropriate for the Commission to "adapt to the changing patterns in the industry" in fulfilling its statutory mandates.[21]

The Commission's authority to require energy efficiency and demand management programs has been upheld on similar grounds. An Appellate Division court held that requiring demand-side management programs fell within the statutory mandate in PSL Section 5(2) to ensure economy, efficiency, and conservation of natural resources.[22] The court recognized the Commission's broad discretion and judgment in choosing the means of achieving legislative objectives.[23]

Judicial deference has been applied in numerous contexts where the Commission exercised judgment as to the best method of fulfilling its obligations. The Commission has latitude under established case law to adopt different methodologies or combination of methodologies in balancing ratepayer and investor interests.[24] This

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18 Cases 94-E-0952 et al., Competitive Opportunities Regarding Electric Service, Opinion and Order Regarding Competitive Opportunities for Electric Service (issued May 20, 1996).

19 Energy Ass'n of New York State v. Public Serv. Comm'n of the State of New York, 169 Misc. 2d 924 (Albany County Sup. Ct. 1996).

20 Id. at 936 (citing CNG Transmission Corp. v. New York State Public Serv. Comm'n, 185 A.D.2d 671 (4th Dept. 1992)).

21 Id. at 936 (citing Rochester Gas and Electric Corp. v. Public Service Commission of the State of New York, 117 A.D.2d 156 (3d Dept. 1986)).

22 Multiple Intervenors v. Public Service Commission of the State of New York, 154 A.D.2d 76 (3d Dept. 1991).

23 Id.

24 Abrams v. Pub. Serv. Comm'n of the State of New York, 67 N.Y.2d 205, 214-15 (1986); New York State Council of Retail Merchants v. Pub. Serv. Comm'n of the State of New York, 45 N.Y.2d 661, 668 (1978).

includes crafting measures to address competitive and potentially disruptive trends,[25] and adopting proactive responses to the problems of, and opportunities created by, new technologies that might otherwise create stranded utility assets under conventional regulatory methods.[26]

Additional process and stakeholder engagement are contemplated in this proceeding, and in related proceedings. Most of the decisions made in this Order are not self-implementing. In many cases they will require further collaborative effort. Just as important, the future direction of REV will need to be responsive to market developments, and to developments in federal jurisdictions including carbon reduction rules.

III. REV POLICY FRAMEWORK

A. Summary of the Vision

There are many possible regulatory approaches, business models, and market designs for electricity, but each must deal with the inalterable physical properties that make electricity a unique commodity and service. Electricity is a real-time product, produced and consumed almost simultaneously. Contract paths do not determine the flow of power, and supply and usage must be in continuous balance across the entire system. For this reason, the power grid is best thought of as a single machine. Moreover, affordable and reliable electric service is essential to a healthy and growing economy. Regulation and markets are constrained by these basic economic and physical facts and must develop rules to achieve system balance that are economically and environmentally sustainable while maintaining constant and reliable supply.

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25 County of Westchester v. Helmer, 296 A.D.2d 68, 74 (3d Dept. 2002); Multiple Intervenors v. Pub. Serv. Comm'n of the State of New York, 154 A.D.2d 76, 80 (3d Dept. 1990).

26 Kessel v. Pub. Serv. Comm'n of the State of New York, 136 A.D.2d 86, 97, 99-100 (3d Dept. 1987).

Viewing the electric grid as a single machine also means that each customer premise and every power consuming device is, in actuality, a part of the grid. Today, the customer side of the grid represents an enormous and largely untapped resource to improve the value of the system.

REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management and operation of the electric system. The system values of distributed resources will be monetized in a market, placing DER on a competitive par with centralized options. Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid.

The more efficient system will be designed and operated to make optimal use of cleaner and more efficient generation technologies. Weather-variable renewable resources will be made more economically efficient by increased use of load control, smart devices, and storage. The values of customer-sited generation – both reliability and environmental – will be recognized in markets. The system will encourage substantial increases in deployment of these technologies.

Enabling these markets will require modernization of infrastructure and operations, particularly communication and data management capabilities. The result will be an increase in the efficiency, responsiveness, and resilience of the system, with reductions in costs and carbon emissions, and increases in customer value.

The framework developed here will define good utility practice for the new century. In response to developments in technology, markets, and the environmental, the responsibility to ensure clean and reliable service at just and reasonable prices requires changes in the way the electric system is planned and operated.

The reformed electric system will be driven by consumers and non-utility providers, and it will be enabled by utilities acting as Distributed System Platform (DSP) providers. Utilities are responsible for reliability, and the functions needed to enable distributed markets are integrally bound to the functions needed to ensure reliability. Technology innovators and third party aggregators (energy service companies, retail suppliers and demand-management companies) will develop products and services that enable full customer engagement. The utilities acting in concert will constitute a statewide platform that will provide uniform market access to customers and DER providers. Each utility will serve as the platform for interface among its customers, aggregators, and the distribution system. Utilities will respond to new trends by adding value, thereby retaining customer base and the ability to raise capital on reasonable terms.

Simultaneously the utility will serve as a seamless interface between aggregated customers and the NYISO. The NYISO will be able to reflect the impact of active load management in grid planning and operations, and the wholesale supply markets will evolve to properly value dynamic load management. The objective of system optimization extends beyond the physical integration of distributed resources. Central generation, large-scale renewable resources, and transmission are critical system components. Efficient integration of DER will require consistent treatment of market dynamics and values across all segments of the grid.

Reforming the Commission's ratemaking practices will be critical to the success of the REV vision. Under current ratemaking, utilities have little or no incentive to enable markets and third parties in creating value for customers. Rather, utilities' earnings are tied primarily to their ability to increase their own capital investments, and secondarily to their ability to cut operating costs, even at the expense of customer value. Utility earnings should depend more on creating value for customers and achieving policy objectives. Rather than simply building infrastructure, utilities could find earning opportunities in enhanced performance and in transactional revenues. We intend to address these issues in detail in a "Track Two" order and in subsequent rate proceedings.[27]

The REV vision is strongly supported by parties. Of 81 comments received on the Straw Proposal, a large majority approved the Commission's general goals. Many of the supportive comments represent numerous parties collected into coalitions to provide more effective participation in stakeholder efforts. Most parties have specific concerns; these are discussed below in the context of individual issues.

The subjects addressed in REV are not unique to New York. It would be impossible to list all of the related developments in other jurisdictions, but prominent examples include integration of distributed resources in California and Hawaii,[28] consumer markets and emerging technologies in Texas,[29] grid modernization in Massachusetts,[30] and performance ratemaking in Minnesota and the United Kingdom.[31] National laboratories also play an important role providing research, practical demonstrations, and dissemination of information and expertise. The Electric Power Research Institute has begun an initiative to develop information and tools to encourage

[27] Ratemaking issues are discussed in more detail in the April 2014 Staff Report and Proposal. Without predetermining any particular results at this time, we underscore the critical tie between the reforms authorized in this Order and ratemaking reforms.

[28] See, e.g., Public Utilities Commission of the State of California, Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769; Hawaii Public Utilities Commission, Case 2014-0192, Proceeding to Investigate Distributed Energy Resource Policies.

[29] See, e.g., Public Utility Commission of Texas, Project 39764, Issues Relating to Energy Storage and Emerging Technologies, Project 40372, 2013 Scope of Competition Report in Texas Electric Markets.

[30] D.P.U. 12-76-B, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.

[31] E21 Initiative, Phase 1 Report, Charting a Path to a 21st Century Energy System in Minnesota, December 2014; Office of Gas and Electricity Markets, RIIO: A New Way to Regulate Energy Networks, Final Decision, October 2010.

collaboration in developing an integrated grid. The implementation of REV[32] will occur with reference to, and informed by, related initiatives throughout the industry.

B. Challenges and Opportunities

The Public Service Law entrusts the Commission with responsibility to ensure that utility service is safe and reliable, at just and reasonable rates, with care for the natural environment. The challenges and opportunities now facing the electric industry and electric customers, taken in the aggregate, lead to a conclusion that conventional utility and regulatory practices no longer represent the best approach to satisfying our responsibilities. The confluence of cost, reliability and environmental concerns cannot be satisfactorily resolved under a business as usual approach. In order to fulfill its statutory duty, the Commission must consider new approaches.

As noted above, thought leaders throughout the energy industry have discussed these problems in recent years. Many have actively participated in this proceeding, as parties and as advisors.[33] The challenges and opportunities summarized below are detailed in the two Staff reports, in party comments, and in the numerous sources cited in the Bibliography to the April 24 Staff report as well as in this Order.

The following discussion identifies and analyzes the trends driving our regulatory reforms. For convenience, these trends are broken into four categories: regulatory models and economic efficiency; system modernization for a digital economy; clean energy and environmental responsibility; and universal service. We employ these distinctions for the sake of clarity; however, there is a great deal of overlap and cross-reference among the categories. A principal purpose of REV is to bridge artificial gaps

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[32] As used throughout this order, "REV" refers not to any single action of the Commission but rather to a series of interrelated initiatives and opportunities, as described in the REV Policy Framework and as tied to similar related initiatives of the State.

[33] In particular, the Rocky Mountain Institute, the Regulatory Assistance Project, PointProspect Consulting, and the New York State Energy Research and Development Authority (NYSERDA) have provided invaluable consulting assistance.

created by our regulatory structure, and to account for values and costs that range across conventional categories. Examples of potential opportunities provided here are illustrative, not exhaustive.

1. Regulatory Models and Economic Efficiency

Challenges:

System, design, development and utilization. The existing electric system was designed and developed at a time when consumer demand was growing and viewed as inelastic. Economies of scale and limits in control and computing technology meant that central station power plants were deemed superior to distributed energy resources. These factors led to the development of an integrated system during the twentieth century that produced power that was reliable and economically efficient.[34]

The regulatory system that was used to set prices for electric service reflected the centralized model of the industry. For most of the last century, electric utilities were regulated as integrated monopolies that generated, transmitted and delivered power. In exchange for an obligation to serve all consumers at reasonable rates, regulators provide utilities with the ability to recover expenses used to provide service and a fair return of and on capital. The regulatory framework was designed to ensure that utilities were not charging monopolistic rents and at the same time to provide these companies with the ability to raise the significant capital required for the system at a low cost. In the last decade of the century, New York and many states found that for many reasons, the supply sector of the industry no longer should be considered a natural monopoly, and restructured the industry to support competition both in the source of supply and access to consumers. At the same time, the delivery elements of the system, transmission and distribution were retained under traditional regulation.

[34] Adjusted for inflation, the national average residential retail price of electricity fell from 20.8 cents per kwh in 1960 to 11.32 cents per kwh in 2000, as costs were spread across a sales base that increased its usage by 422% over that time period.

The physical makeup of the grid means that the cost of electricity reflects the need to have resources on hand that are only required a few hours per year. Since electricity has not been amenable to storage in large amounts, the obligation to serve has required that the system be designed to meet the integrated peak usage and to have sufficient reserves in generation and delivery to retain reliability in the face of unanticipated unit losses. The introduction of air conditioning and changes in our economic base led to the development of a system in New York and elsewhere that consumes on average 18,600 MW of power during much of the year but can rise to nearly 34,000 MW during hot summer days.[35] This necessarily means that for many hours of the year, large portions of the generation and delivery systems are not used to meet consumer demand. Significant reserve margins and spinning reserves as well as redundant delivery systems are needed to enable the dispatch of generation to meet instantaneous consumption. The utilization rate of New York's electric system averages under 60 percent, and the trend is negative. Peak loads are growing five times faster than base sales. A centralized system also requires power to flow over long distances, with corresponding losses due to the inefficiency of electric conduction. From power plant to customer, approximately 7-8% of generated power is lost in the process of being transmitted and distributed, although the percentage may be much higher during peak loading. Energy losses in the generation of power from combustion are very large, ranging from 65% losses for older fossil plants to 50% for newer plants.[36]

Aging infrastructure and flat sales. The post-WWII era saw a great expansion of electric generating and delivery system capabilities in New York.[37] While

[35] Numerical descriptions of system characteristics, unless otherwise noted, are provided by Staff analysis.

[36] National Renewable Energy Laboratory, Cost and Performance Assumptions for Modeling Electricity Generating Technologies, November 2010. For a comprehensive overview of energy production and usage flows, see Lawrence Livermore National Laboratory, US Energy Flows 2012.

[37] Consolidated Edison, for example, built 32 substations and switching stations from 1950 to 1960, compared with 4 between 1990 and 2000.

this infrastructure has been maintained and repaired over the years, much is now at or beyond its optimal service life. Based on planning reports filed by the state's utilities and the NYISO, approximately $30 billion will need to be spent over the next decade to maintain current capabilities, compared with $17 billion over the past ten years. The need for these investments will place pressure on utility rates.

Not only will replacing the infrastructure be more expensive than the existing system, shrinking energy sales and a poor load factor means the recovery of the investment will be made over a smaller consumer base. Growth rates in electric utilities' sales have declined steadily over the past five decades, and sales are currently projected to grow at a pace of only 0.16 percent per year through 2024.[38] To some extent this reflects the success of the state's energy efficiency policies which have reduced customer bills and air emissions. From the standpoint of utility rates, however, a flat sales base means that increased costs from replacing infrastructure cannot be spread across a growing sales base and must instead be absorbed by existing customers.

The need for investment also presents an opportunity to develop alternatives; a substantial portion of the infrastructure used in today's system was designed and built prior to the existence of the internet. But the longer the delay in identifying alternatives, the more risk of locking in inefficient investments.

Fuel diversity. Overdependence on any fuel that may become scarce makes the system vulnerable, both for price and for reliability. Driven by economic and emission concerns, the state's reliance on natural gas for electric generation increased 96% from 2004 to 2012. This is a positive trend in the near term, but in the long term dependence on gas needs to be moderated. The price of natural gas now establishes the market price for electricity more than 50% of the time. Relatively low gas prices have resulted in net savings to consumers over recent years, but vulnerability to price fluctuation and periodic spikes remains. Average monthly day-ahead electricity prices

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[38] Statewide electric sales growth averaged 3.8% from 1966-1976, 1.5% from 1976-1986, 1.4% from 1986-1996, 0.9% from 1996-2006, and 0.3% from 2003-2013.

regularly fluctuate in ranges exceeding 20% relative to the prior month. Occasional extreme events can create even larger spikes; gas transportation constraints caused price spikes in the winter of 2013-2014, with an estimated total cost to New York customers of over $1.0 billion. Because local natural gas prices, at times, can be dramatically affected by gas pipeline bottlenecks, reliance on gas also means that New York can be adversely affected by price consumption spikes in neighboring markets.

System Benefits Charge. When it was initiated in 1996, the System Benefits Charge (SBC) was intended to maintain certain public benefits in a time of transition.[39] The SBC has subsequently grown into the primary vehicle for achieving the State's efficiency and clean energy goals. Although a great deal has been accomplished through the SBC,[40] achieving the carbon reduction goals proposed in the Draft State Energy Plan[41] through existing SBC approaches would require large increases in the surcharge which already represents a substantial portion of some customers' bills. Existing SBC approaches do not, for the most part, address the root inefficiencies in the electric system; nor do they do enough to build a lasting market structure to support investment in, and adoption of, clean energy at scale. Rather than simply addressing the ongoing symptoms of the problems, our efforts must be more focused on systematic solutions. More importantly, the regulatory system must begin to properly value the attributes that the SBC has been used to promote, and ensure that clean energy is integrated in core electric system operations.

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[39] Case 94-E-0952, <u>supra</u>, at 62.

[40] As of the end of 2014, SBC programs have produced approximately 13 million MWh of renewable generation and electric efficiency savings and over 14 million MMBtu in heating savings.

[41] The Draft Plan proposes a 50% reduction in carbon by 2030, placing the State on a pathway toward an 80% reduction by 2050.

Opportunities:

Modernized Regulation and Markets. From the perspective of the utility investor, the current regulatory system places a premium on capital deployment. In contrast to competitive firms that are damaged by low rates of capacity utilization, utilities under traditional rate of return regulation are indifferent as to whether the rate of capital utilization is efficient. We do not have to look far from the electric delivery system, however, to identify the efficiency improvements that competition can provide to an historically regulated monopoly service. One of the benefits of wholesale power competition has been the improved efficiency of electric generation. In New York and other regions that restructured their industry, the introduction of competition led to the retirement of older and uneconomic plants, reduced outage periods, and improved capacity factors, all of which led to consumer benefit.[42]

It does not follow that competition could also provide standard electric delivery services. Under the present regulatory model, however, distributed energy competes with the standard methods of supplying *and* delivering power. The opportunity before us is to set forth a regulatory and business model for the traditional utility and its investors that prompts encouragement of this form of competition, rather than opposition. In doing so we can avoid the inefficient use of capital that occurs when government and monopolists refuse to remove barriers to the benefits that occur from innovation and competition. In Track Two of this proceeding we will undertake the ratemaking changes that are needed to support the economic expansion and use of DER in the industry. In

[42] See, The New York Independent System Operator: A Ten Year Review, April 12, 2010. While wholesale supply competition has demonstrable benefits, power markets are not yet fully competitive and continue to evolve. The development of price sensitive demand through DER investment will continue to improve competitiveness of the wholesale markets. At the same time, it will be important that the wholesale markets make any appropriate changes to adapt to new forms of competition in a changed regulatory framework, to ensure that these competitive benefits occur. Indeed, the Commission has been requested by Governor Cuomo to undertake such an analysis as part of the State's reform efforts (see 2015 New York State of the State Address).

this Order, we focus on the changed business model for the distribution utility that can support such growth.

Intelligent infrastructure investment. While much of the aging infrastructure will need to be replaced, dynamic load management and other forms of DER can reduce near term needs in targeted areas and long term needs throughout the system. The viability of intermodal competition provided by DER means that the monopoly function of power delivery is now more tied to ensuring reliability than it is to building delivery infrastructure. The forecasted size of conventional utility investments indicates a need to develop optimal planning around new models as soon as possible. Where utility system investments cannot be avoided or deferred, they can be turned to the development and service of a modernized grid. Investments needed to build a more intelligent network will be substantial and, in the near term, may be comparable in size to investments that would otherwise be made under a business as usual scenario. In the long term, these investments will allow more system needs to be fulfilled by third parties without placing the full burden on utility consumers, while improving the reliability, costs and resiliency of the overall system.

Stabilizing customer bills. The pressure on rates that will be caused by aging infrastructure replacement, reliability and security needs, carbon rules, and other factors can be mitigated by the cost reductions that are available through increased system efficiency achieved through markets and improved regulation. Increasing the responsiveness of demand will reduce price volatility in the near term and price inefficiency in the long term. If, for example, the 100 hours of greatest peak demand were flattened, long term avoided capacity and energy savings would range between $1.2 billion and $1.7 billion per year. Avoided line losses achieved by distributed generation can further improve system efficiency. Total line losses cost approximately $200-400 million per year. Beyond these examples of direct cost reductions, markets established under REV will enable a range of options that will reward customers for participating in system optimization, and assist in control of customer bills.

Optimizing fuel diversity. Responsive demand management, combined with more diverse generation options, can reduce the volatility consequences of gas dependence while retaining the benefits of using gas as a primary fuel source. Beyond that immediate advantage, the integration of a wide array of distributed resources, including dynamic load management, can establish a flexible system that is immune from dominance of any particular generation source.

Realizing the potential of storage and innovative technologies. The instantaneous nature of electricity places a premium on storage while, at the same time, making storage capabilities difficult to achieve. Historically, storage on a large scale has been accomplished by large reservoirs of water. Other than stored hydro, the chief way of balancing system load has been to convert stored fossil fuels, through combustion, into electricity.[43] In recent years, the cost of various storage technologies has declined, and their capabilities have increased.[44] In addition to various forms of battery storage, building based thermal storage allows business and residential consumers to reduce bills through use of sophisticated sensors, thermostats and building control systems.[45] This ability to use information to obtain the advantage of thermal storage, as well as deployment of batteries and other forms of storage located on customer premises or at key locations in the distribution system, has the potential to greatly decrease system costs, including active and reactive power control and load balancing.[46] While storage is

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43 Capacitors are also used to balance the system but have a very short discharge duration.

44 See, e.g., Sandia National Laboratories, DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA; Advanced Battery Forecast, Materials and Next Generation Chemistries, GE Research Battery Conference, December 5, 2014.

45 Similar techniques can be applied to utilize domestic water heating as a storage medium.

46 U.S. DOE Electricity Advisory Committee 2014 Storage Plan Assessment Recommendations; U.S. DOE Electricity Advisory Committee 2012 Storage Report: Progress and Prospects; and The Value of Distributed Electricity Storage in Texas, Brattle Group, November 2014.

given as an example here, opening markets to enhance system value will create similar opportunities for other technologies as well.

2. System Modernization for a Digital Economy

Challenges:

Information Technology. The modern economy is increasingly dependent on electricity. The power needs of the digital economy increase the need for reliability, power quality, and resilience in the power supply.[47] The massive increases in efficiencies of the digital economy, however, have not yet been enjoyed within the electric industry. Real-time interoperability is commonplace in most service industries, while information flow in electric distribution networks remains undeveloped.[48] The rise of information technology creates a need for change in the electric system but also provides the tools to accomplish that change.

Cyber security. The centralized power distribution system is vulnerable to a real and ongoing threat of massive failure caused by cyber attack. No static set of protective measures can be defined, due to the constantly evolving nature of the threat. As communication technology grows in sophistication and points of entry to utility systems increase, risk of harmful entry increases also.

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[47] As a consequence of this development, the cost to the economy of power outages is an increasing concern. An older study estimated the annual national cost of grid outages at $79 billion. LaCommare and Eto, Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Lawrence Berkeley National Laboratory, September 2004.

[48] Communication functionality of customer-sited DER does not currently extend to distribution system operators, which limits its potential to provide system value. See, e.g., Advanced Inverter Functions to Support High Levels of Distributed Solar, National Renewable Energy Laboratory, November 2014.

Opportunities:

Customer choice and animating markets. The electric system is increasingly anachronistic in the limited choices offered to customers and limited interoperability between customers and providers. Public comment in this proceeding has been clear in the demand for more control over energy choices. The intent of REV is to enable electric customers to drive markets in a productive and efficient way.

Reliability and power quality. The digital economy depends on highly reliable electric supply. The cost of maintaining reliability across a centralized system becomes unacceptably high where the system is built to serve unmanaged peak demands. Dynamic load management will reduce the cost of providing reliability on a systemwide basis, while DSP markets will also enable enhanced service to commercial and industrial customers with unique power quality needs.

Resilience. A less centralized and more automated system, which may include microgrids, will have greater operational visibility, and ability to isolate circuit faults, resulting in reduced damage and improved recovery times following outages from weather events or other causes. Distribution automation devices such as intelligent switches and reclosers add flexibility and the ability to react, isolate and respond to system conditions in real time. Upgraded design, installation and maintenance standards for electrical infrastructure also help prevent electrical damage before it occurs and improve performance in conjunction with advanced technologies and practices.

System security. There is no permanent solution to the problem of cyber security other than constant reevaluation and response to emerging threats and trends. Increasing points of entry has the potential to increase risk. A decentralized system, however, that is capable of segmentation and contains self-sufficient microgrids or similar configurations with appropriate firewalls, may be more resilient against the impacts of a wide scale cyber attack.

3. Clean Energy and Environmental Responsibility

Challenges:

Climate. Climate change poses several different types of challenge to the electric industry. First, and most obvious, is the need to reduce carbon emissions. This need extends beyond the current electric generation fleet, because a serious effort to meet carbon reduction goals will also require a shift toward electric transportation and building heating with an accompanying expansion of electric generating capacity. Second, reliability and resilience concerns driven by severe weather will increase infrastructure costs and may also impel more customers to seek self-generation solutions. Third, increasingly severe weather trends will eventually force a wider range of load forecast planning scenarios, which would exacerbate the inefficiency of planning to meet uncontrolled system peaks. Fourth, the shift toward greater reliance on natural gas, which has been a first-stage carbon reduction measure, has led to fuel diversity concerns and poses a challenge to meeting long-term carbon goals. Finally, the economic value of a weather-variable non-combustion generation fleet can be greatly enhanced by the demand-side flexibilities envisioned in REV.[49]

Plug-in electric vehicles. As mentioned above, achievement of carbon reduction goals will likely require electrifying transportation, including a substantial shift to electric vehicles. A large penetration of electric vehicles has potential to strain distribution infrastructure, as recharging may occur during evening hours which are already a summer peak time on many residential distribution circuits.[50]

Combined heat and power. The largest-scale distributed generation (DG) tends to be combined heat and power, including gas-fired cogeneration and fuel cells, which generally makes a more efficient use of fuel than centralized generation and avoids

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[49] See, e.g., Mills and Wiser Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California, Ernest Orlando Lawrence Berkeley National Laboratory, June 2012.

[50] U.S. DOE, Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors, December 2014.

the line losses that result from power transmission. For distribution systems to accommodate much greater penetration of combined heat and power, changes to pricing, physical interconnection procedures, backup-power rates, and system controls will be needed.

Integrating distributed renewable generation. In recent years the cost of photovoltaic power (PV) has reduced dramatically,[51] and the trend toward increased penetration of PV is expected to continue.[52] This is generally a very positive development, but it presents challenges. The distribution system, as traditionally configured, could limit the penetration of distributed generation; a very high penetration of distributed generation has the potential to disturb the operation of distribution circuits unless intelligent controls are used.[53] Even where this problem does not exist, the perception of a reliability concern can inhibit new projects. Second, PV is currently enabled by net metering, which is an imprecise measure of the value of PV to the system and, at high percentages of total load, could place an inequitable burden on customers that are not able to own or install PV.[54]

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[51] Installed PV prices fell by an average of 6-8% per year during the period from 1998 to 2013. Lawrence Berkeley Lab, Tracking the Sun VII, The Installed Price of Photovoltaics in the United States from 1998 to 2013, p. 13-14. See also, Lazard's Levelized Cost of Energy Analysis – Version 8.0, September 2014.

[52] From 2003 to 2012, total PV installed under NYSERDA's incentive program increased from 0.37 MW to 62 MW.

[53] Hawaii Public Utilities Commission, Case 2011-0206, Proceeding to Investigate the Implementation of Reliability Standards, Order 32053, at 35 ff.

[54] Net metering penetration is currently capped at 6% of each utility's load; at these levels the Commission has determined that disparate rate impacts are not substantial. Case 14-E-0151 et al, supra.

Opportunities:

Reduced emissions and system heat rate. Although distributed generation is not inherently lower in emissions, or greater in efficiency, than centralized generation, a system biased steeply toward centralized generation prevents the cleanest and most efficient mix of generation from being developed. Combined heat and power at the distributed level can be a highly efficient way to meet energy needs;[55] many high-usage customers already rely on some form of distributed generation. Through tariffs and markets that fairly price and value these resources, customers will be able to optimize their size for both individual use and system value. Increased PV, wind, fuel cells, geothermal systems, and energy efficiency will reduce emissions. Creating viable markets for distributed resources and monetizing their values will enable development of distributed resources to complement central generation to optimize the emission and fuel efficiency profile of the total generation fleet. Systems and technology improvements at the wholesale level will lead to efficiency improvements throughout the grid.

Energy efficiency. Energy efficiency, the kilowatt-hour not consumed, remains among the most cost effective ways to reduce emissions. Experience with efficiency programs in New York and elsewhere has demonstrated that improved pricing and markets for efficient products yield substantial savings for customers. There is a large potential for further efficiency gains, to reduce emissions and customer bills that are not being effectively captured by current approaches. Where subsidy programs with budget-driven participation caps have the effect of displacing market development, the potential for efficiency gains is limited. Meeting the goals described in the Draft State Energy Plan will require more efficiency than can be accomplished using only surcharge-funded programs. Market transformation strategies will leverage more customer investment to accomplish greater efficiency than is currently contemplated in state program targets.

Accommodate low-carbon generation. Aside from the direct effect of enabling more options in clean generation, the dynamic load management contemplated

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[55] See, e.g., U.S. EPA, Catalog of CHP Technologies, September 2014.

by REV will also make it functionally feasible to operate a very-low-carbon generation system. Most foreseeable generation scenarios that might accomplish an 80% by 2050 reduction involve a mix of weather-variable generation such as wind and solar, and invariable base load generation.[56] A system consisting of weather variable and invariable generation will require a highly responsive demand side and/or the ability to store electricity on a large scale.[57] The dynamic load management of REV would make this possible.

Electrification of transportation systems. DSP markets can assist a transition to electric vehicles by turning what could be a strain on distribution systems into a valued asset. Electric vehicles present great opportunity if coordinated with grid functions to provide storage and voltage support. Electric vehicles can also increase utility sales and reduce rate pressure caused by infrastructure needs.

Geothermal heating systems. Achieving long range carbon goals will likely require a transition away from fossil fuels in building heating systems as well as transportation. As many participants in public hearings pointed out, ground-source heat pumps powered by electricity are commercially available and economically feasible for many customers.[58] Dynamic load management markets will provide additional value opportunities for customers employing ground-source heat pumps, as units can be cycled to optimize system loads.

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[56] New York Climate Action Council, Interim Report, Chapter Four.

[57] See, e.g., Sorknaes, Maeng, Weiss, and Anderson, Overview of the Danish Power System and RES Integration, July 2013.

[58] Heat Pumps Potential for Energy Savings in New York State, NYSERDA, July 2014; Updated Buildings Sector Appliance and Equipment Costs and Efficiency, United States Energy Information Administration, 2013; Ground-Source Heat Pumps: Overview of Market Status, Barriers to Adoption, and Options for Overcoming Barriers, U.S. Department of Energy Energy Efficiency and Renewable Energy Geothermal Technologies Program, Feb. 3, 2009.

4. Universal Service

Challenges:

Affordability. Competitive markets and other New York initiatives have worked to bring the state's average industrial rates below the national average. Many customers in New York, however, face affordability challenges. On average, approximately one in eight residential customers is in arrears for over 60 days, and over 250,000 customers per year experience involuntary shut-offs.

Contraction of Utilities' Customer Base. Customers will drive markets, and if the existing regulated markets do not provide choices that customers want or need, customers will eventually find alternatives. Under a conventional regulatory regime, the trends toward declining cost of self-generation, and increasing need for reliability, combined with price pressure on regulated utilities, present the risk of an eroding customer base that could increase the utilities' cost of capital and require those costs to be collected from a shrinking pool of customers.[59] One concern under the status quo is that only businesses and more affluent residential consumers might have the capability of gaining the benefits of DER. Without the reforms we are enacting, the current trajectory of DER deployment could create unintended harm to lower income consumers, creating an unacceptable gap in the quality and price of electric service.

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[59] See, e.g., Kind, "Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business", January 2013; McKinsey & Company, "The Disruptive Potential of Solar Power", McKinsey Quarterly, April 2014; Graffy and Kihm, Does Disruptive Competition Mean a Death Spiral for Electric Utilities?, Energy Law Journal, Vol. 31, No. 1 (2014): 1-44; Rocky Mountain Institute, "The Economics of Grid Defection: When and Where Distributed Solar Generation Plus Storage Competes with Traditional Utility Service", (2014); Lawrence Berkeley National Laboratory, "Utility Business Models in a Low Load Growth/High DG Future: *Gazing into the Crystal Ball?"* April 2013; Barron's Income Investing: Barclay's Downgrades Electric Utility Bonds, Sees Viable Solar Competition, May 23, 2014.

Opportunities:

Maintain universal affordable service. Customers' demand for reliable, clean, and economic power will drive markets. As options in self-generation and storage become more viable, utilities that cannot provide comparable value will experience an erosion of their customer base, resulting in risk to customers with fewer options. The Commission has begun to address this challenge through separate proceedings, including ones that are specifically focused on the needs of low- income consumers and the introduction of community aggregation and community net metering. The comprehensive reforms we initiate here will complement these efforts. DSP markets can harness distributed resources to the service of the broader system and forestall the creation of a gap, by allowing customers to achieve the mutual economic and reliability benefits of remaining interconnected.

Secure utilities' financial stability. Universal service requires financially viable utilities, securing capital at reasonable cost to support a grid that serves the entire public. Affordability of rates is balanced against the need for utilities to earn a reasonable return on investments. These are familiar themes that have been at the heart of ratemaking practices for a century. The trends identified here, however, add a new factor to this balancing. The maintenance of both universal service and financial stability will depend on integrating customer choice and technology into utility practices. Under REV, utilities will respond to disruptive trends by adding value to various activities in the evolved power economy, with the concomitant opportunity to earn revenues from new service offerings and the ability to raise capital on reasonable terms.[60]

C. Conclusion

Utilities, and this Commission, could respond to these challenges by clinging to the traditional business model for as long as possible, relying on protective

[60] For a discussion of the difference between cost-recovery and value-creation responses to disruptive threats, see Graffy and Kihm, supra.

tariffs, regulatory delay, and other defenses against innovation. A variation on this approach would be to assume a reactive posture, addressing issues only when they have grown into critical or highly visible problems. Alternatively, we can identify and build regulatory, utility and market models that create new value for consumers and support market entrants and this new form of intermodal competition – in other words, embrace the changes that are shaking the traditional system and turn them to New York's economic and environmental advantage.

We decisively take the latter approach. For a century, policy goals were adequately served by regulatory methods that encouraged a static and unidirectional model of utility service. In the modern economy, the goals of reliable, affordable and clean electric service will not change; but the methods of achieving them must. REV is both an opportunity to improve greatly on the status quo, and a response to a convergence of trends that make business as usual unsustainable in the long run. The challenges that force us to question traditional methods and assumptions also reveal a pathway toward a more efficient, customer-friendly and sustainable model.

IV. ANIMATING MARKETS FOR DISTRIBUTED ENERGY RESOURCES

The policy framework described above will be the lens through which the Commission views individual policy and market development issues. Transforming the electric distribution industry entails a complex set of issues that will be developed over time by interested parties, including customers and industry, through market participation. Ultimate responsibility resides with the Commission in fulfillment of its statutory duties. The Commission will provide policy initiative and guidance, while participants will provide initiative in the development of products and market practices.

Exhibit 3

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

ORDER ON NET ENERGY METERING TRANSITION, PHASE ONE OF VALUE OF DISTRIBUTED ENERGY RESOURCES, AND RELATED MATTERS

Issued and Effective: March 9, 2017

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on March 9, 2017

COMMISSIONERS PRESENT:

Audrey Zibelman, Chair
Gregg C. Sayre
Diane X. Burman, concurring

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

CASE 15-E-0082 - Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program.

ORDER ON NET ENERGY METERING TRANSITION, PHASE ONE OF VALUE OF DISTRIBUTED ENERGY RESOURCES, AND RELATED MATTERS

(Issued and Effective March 9, 2017)

BY THE COMMISSION:

INTRODUCTION

This order achieves a major milestone in the Reforming the Energy Vision (REV) initiative by beginning the actual transition to a distributed, transactive, and integrated electric system. Our decisions here represent the first steps in the necessary evolution of compensation for Distributed Energy Resources (DER) from the mechanisms of the past to the accurate models needed to develop the modern electric system envisioned by REV through the development of Value of Distributed Energy Resources (VDER) tariffs. The impacts of the electric system on the lives and interests of New York residents are both significant and wide-ranging, from the health, safety, and business needs for secure and reliable energy to the financial impacts of utility bills to the environmental impacts of the generation of electricity. However, as the Commission has recognized through the REV initiative, many aspects of the electric system reflect legacy policies, technologies, and interests and have not been sufficiently reformed to reflect developments over the past decades, including technological developments, evolving consumer and market interests, and full recognition of environmental externalities. A failure to bring the electric system and industry fully into the modern world and to keep it apace with continuing developments could have disastrous consequences, including a failure to meet modern reliability needs and expectations, enormous and avoidable costs associated with the inefficient replacement of aging components, and unchecked emissions of greenhouse gasses and other pollutants. In addition, DER participation should be open to all customers, including low-income customers, and should be coupled with strong consumer protection measures.

The transition described herein is guided by core principles in the REV Framework Order.[1] First, the unidirectional grid must evolve into a more diversified and resilient distributed model engaging customers and third parties. Second, ensuring universal, reliable, resilient, and secure delivery service at just and reasonable prices remains a function of regulated utilities. Third, the overall efficiency of the system and consumer value and choice must be improved by achieving a more productive mix of utility and third-party investment.

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[1] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2016) (REV Framework Order or Track One Order); Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order).

The Commission also recognizes that existing DER business models are well-established and based largely on net energy metering (NEM). These business models reflect the capabilities and needs of the electric system at the time they were designed and they appropriately served to open up markets and drive initial development. But such business models and NEM in particular are inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers. As such, they are unsustainable. To the degree that they over-compensate DER providers by transferring their fair share of fixed costs onto other customers, they operate now in a manner that will not sustain wide-scale deployment as the inherent subsidies reach a level that is oppressive to non-participants. While it is natural for the existing DER businesses to want to maintain the business models and financial support that they have enjoyed, the public interest requires the development of and prompt transition to more accurate valuation and compensation mechanisms for DER, particularly for project types currently compensated through NEM, that accurately reflect and properly reward DER's actual value to the electric system and that ensure all customers pay their fair share for the costs of grid operation and benefit from the value they provide.

The VDER Phase One tariffs will provide immediate improvements in granularity in understanding and compensating for the value of DER to the electric system while setting the foundation for continual improvement. This transition will encourage the location, design, and operation of DER in a manner that maximizes benefits to the customer, the electric system, and society while also ensuring the development of clean generation needed to meet the necessary and aggressive goals embodied in the Clean Energy Standard (CES) and in this order. This transition will also ensure that the values and costs created by DER will be identified, monitored, and managed to ensure that all customers continue to receive safe and adequate service at just and reasonable rates, and that participation in DER markets is open to all customers, including low-income customers.

To ensure that development and interconnection of distributed generation (DG) projects can continue unabated, a transitional period is necessary so that the market and customers can fully understand the mechanisms of and incentives provided by the methodology adopted in this order. During an initial period, commencing with the date of this order, new projects will continue to receive compensation based on NEM methodologies, except that those projects will be limited to receiving such compensation to 20 years before transitioning to new compensation mechanisms; this initial compensation mechanism is described as Phase One NEM in this order. While Phase One NEM contains inefficiencies similar to NEM as a compensation methodology, the term limitation will offer some incentives for developers and customers to consider the impacts of the location, design, and operation of DER on the electric system. Phase One NEM is subject to filing deadlines to ensure that it applies only to projects that are already in advanced stages of development and, for Community Distributed Generation (Community DG or CDG), to a limited capacity allocation to manage any impact on non-participants.

During this initial period, the Department of Public Service Staff (Staff) will engage with utilities and stakeholders to finalize recommendations to implement a new compensation mechanism. Once the recommendations have been filed and received public scrutiny, the Commission will take further action, as early as this Summer, to fully implement compensation for new projects that reflects the values created by those projects in a more accurate and granular manner, described in this order as Value Stack compensation. Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified, the Value Stack will include a Market Transition Credit (MTC) for CDG projects that provides compensation for initial projects that is substantially similar in value to compensation under NEM.

In this order, the Commission (a) adjusts the current interim floating ceiling on new Public Service Law (PSL) §66-j NEM projects by setting a new fixed ceiling that limits the level of new projects in favor of transitioning to a new regime; (b) establishes a VDER Phase One tariff consisting of two components, the Phase One NEM tariff implementing a new DER program similar to NEM with some exceptions, and the Value Stack tariff implementing a new, more comprehensive DER program based on monetary crediting for net hourly injections; (c) establishes capacity-based allocations for mass market and CDG projects intended to limit the potential impacts of the VDER Phase One tariff on non-participants to an incremental net annual revenue impact of approximately 2% for each utility; (d) allocates the costs associated with the VDER Phase One tariff to the customers who benefit from the savings associated with the compensated DER, or where the groups of benefitted customers have not been identified, to the customers within the same service class as the beneficiaries; (e) allows participating customers to pair energy storage technologies with their eligible projects; (f) directs development of proposals for next steps that can be taken to reduce, eliminate, or mitigate market barriers, bill impacts, and CDG project costs; (g) directs NYSERDA to file new or revised Clean Energy Fund (CEF) investment chapters to support programs aimed to encourage and incentivize low-income customer participation in CDG projects, as well as to support the transition to the Value Stack; (h) directs Staff to consider options to encourage low-income customer participation in CDG including an interzonal CDG credit program and tailored approaches for CDG projects that comprise a majority of low-income off-takers; (i) directs Staff to develop an updated whitepaper on DER oversight provisions; (j) directs utilities to make specific filings to enable the full implementation of the Value Stack tariff; and (k) directs the commencement of VDER Phase Two.

LEGAL AUTHORITY

The PSL grants the Commission broad legal authority to prescribe regulatory requirements necessary to carry out the provisions contained therein. For instance, PSL Section 5(1) grants the Commission jurisdiction over the sale or distribution of electricity. Furthermore, PSL Section 5(2) permits the Commission to "encourage all . . . corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Pursuant to PSL Section 65(1), every electric corporation must safely and adequately "furnish and provide [electric] service, instrumentalities, and facilities as shall be safe and adequate and in all respects just and reasonable." Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure "for the purpose of . . . furnishing or transmitting electricity." Pursuant to Section 66(2), the Commission may "examine or investigate the methods employed by. . . corporations . . . in manufacturing, distributing, and supplying . . . electricity," as well as "order such reasonable improvements as will best promote the public interest . . . and protect those using . . . electricity." Moreover, pursuant to Section 66(3) the Commission may prescribe "the efficiency of the electric supply system." Accordingly, the Commission has the jurisdiction over the electric utilities affected by this order to require them to comply with the requirements outlined herein.

In fulfilling its statutory mandate, the Commission has approved tariff provisions and established programs governing service, billing, and compensation for various DER, including distributed generation. For example, each electric utility's Commission-approved tariff includes standby rates, which govern service to large customers that meet a substantial part of their electric needs through on-site generation, and buy-back service, which governs the purchase of capacity and energy by the utility from qualifying customers.[2] Similarly, each electric utility has demand response programs, which offer incentives or compensation for reductions in peak demand,[3] and

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[2] See, e.g., Con Ed Tariff, Schedule for Electricity Service, P.S.C. No. 10 - Electricity, leaves 157-170 and 462-477.

[3] See, e.g., Case 14-E-0423, Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Dynamic Load Management Filings with Modifications (issued June 18, 2015).

several non-wires alternative (NWA) programs are under development, offering compensation to DER, including distributed generation, that supports elimination or deferral of costs associated with traditional infrastructure.[4]

As described in Appendix C, The History of NEM in New York, NEM was established by statute in 1997 and subsequent amendments have expanded eligibility and made other minor changes.[5] The NEM statutes govern compensation and terms of service for customer-generators that interconnect their eligible generating equipment with a utility's system before a rated generating capacity ceiling for that utility's service territory is reached.[6] Once the ceiling has been exceeded, customer-generators are no longer entitled to be provided service, billed, and compensated based on the terms of the statute. The Commission therefore has not only the authority but also the responsibility to define terms of service and compensation for those customer-generators.

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4 See, e.g., Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, Order Establishing Brooklyn/Queens Demand Management Program (issued December 12, 2014).

5 NEM of wind turbines is governed by PSL §66-l, while NEM of all other technologies is governed by PSL §66-j. The terms and conditions of NEM under the two statutes are essentially identical, except that wind is subject to a separately calculated statutory cap of 0.3% of 2005 electric demand for each utility, and therefore is not counted towards the cap that applies to all other technologies.

6 Technically, the statutes do not create a cap, but rather require that each utility offer NEM to eligible customer-generators until the specified capacity is reached. PSL §66-j(3)(a)-(b). Because utility tariffs have always limited NEM based on the minimum capacity required, that capacity level has generally been described, and will continue to be described in this order, as a cap or a ceiling.

PSL §66-j sets initial ceilings of 1% of each utility's 2005 electric demand and provides the Commission with broad discretion to determine what level of NEM above these ceilings is in the public interest. The Commission raised the ceilings several times and ultimately directed that the ceilings float with interconnections.[7] However, in the Interim Ceilings Order, the Commission explained that the floating ceilings were a temporary measure and that, when a new compensation mechanism was developed, the ceilings would be set based on the existing capacity levels.

Where, as here, the Commission finds that additional NEM would no longer be in the public interest, we must determine what form of compensation for new DER projects is consistent with our statutory mandates to ensure safe and adequate service at just and reasonable rates consistent with the public interest and the efficiency of the electric system. Consistent with our statutory duties, with ratemaking principles, and with the goals of REV, in this order we create a compensation structure for those projects based on the benefits they create and the costs they impose.

PROCEDURAL HISTORY

As noted in the REV Track Two Order,[8] Case 15-E-0751 was established to provide a process for determining the value of DER, for both planning and transactional purposes. An extensive collaborative process was established that looked to

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[7] Case 15-E-0407, Orange and Rockland Utilities, Inc. - Petition For Relief Regarding Its Obligation to Purchase Net Metered Generation Under Public Service Law §66-j, Order Establishing Interim Ceilings on the Interconnection of Net Metered Generation (October 16, 2015) (Interim Ceilings Order).

[8] Case 14-M-0101, Reforming the Energy Vision, Track Two Order at 19.

market participants and stakeholders to develop proposals. Although there was active participation and collaboration by a wide range of stakeholders and market participants, it became necessary for Staff to offer straw proposals to facilitate the discussion. Staff provided a number of straw proposals intended to explore approaches that reflected the collaborative discussions. Participating parties provided input on the straw proposals at public, noticed collaborative conferences, as well as during smaller breakout groups established to address specific topics within the straw proposals. The process culminated in a Staff Report and Recommendations (Staff Proposal), filed on October 27, 2016.

The Staff Proposal presents several recommendations of general applicability and details the Value Stack as a proposed valuation and compensation methodology, along with when and how that methodology should apply to various market segments. It also describes several unique aspects for transitioning from NEM, including limited continuation of NEM for mass market customers consistent with our REV Track Two Order and an MTC that Staff proposes be made available to certain projects during the transition from NEM. In the context of developing a VDER Phase One methodology and tariff, Staff identified distinctions among four major market segments, including: 1) on-site, mass-market projects and customers, defined as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand; 2) CDG projects and customers, defined as consisting of an eligible generating facility located behind a non-residential host meter and a group of members located at other sites that receive credits from that facility to offset their bills; 3) remote net metered (RNM) projects and customers where non-residential customers, as well as residential customers who own or operate farm operations, receive credits for excess generation by an eligible generating facility they own, lease, or operate at a site they own or lease, and where those credits are used to offset the bill for meters at one or more other properties that they own or lease; and, 4) large, on-site projects and customers, defined as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. Specific elements of the Staff Proposal related to decisions in this order are summarized in the Discussion section, below.

NOTICE OF PROPOSED RULEMAKING

On October 28, 2016, the Secretary issued a "Notice Soliciting Comments on Staff Proposal," which sought initial comments by December 5, 2016, and reply comments by December 19, 2016. Further, pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) was published in the State Register on November 2, 2016 [SAPA No. 15-E-0751SP1]. The time for submission of comments pursuant to the SAPA Notice expired on December 19, 2016. In addition, a technical conference was held on November 28, 2016. Input was also solicited on process and areas of focus for Phase Two and a number of comments were received by December 23, 2016. Various initial and reply comments on the Staff Proposal were received, including thousands of comments from members of the public, as summarized in Appendix D and addressed below in where relevant. The first section of Appendix D contains short names for commenters; those names are used throughout this order to refer to the commenters.

SEQRA SUPPLEMENTAL FINDINGS

In February 2015, in accordance with the State Environmental Quality Review Act (SEQRA), the Commission finalized and published a Final Generic Environmental Impact Statement (FGEIS) that addressed the potential environmental impacts associated with two major Commission policy initiatives: REV and the CEF. On February 23, 2016, the Commission issued a Draft Supplemental Generic Environmental Impact Statement specifically relating to the CES and on May 19, 2016, the Commission adopted the Final Supplemental Generic Environmental Impact Statement (FSGEIS). In conjunction with the REV Framework Order, the Commission adopted a SEQRA Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions and attached to the Order. The SEQRA Findings Statement was based on the facts and conclusions set forth in the FGEIS.

In conjunction with the decisions made in this order, the Commission has again considered the information in the FGEIS and the SEQRA Findings Statement and hereby adopts a SEQRA Supplemental Findings Statement prepared, in accordance with Article 8 of the Environmental Conservation Law (SEQRA) and 6 NYCRR Part 617, by the Commission as lead agency for these actions. The SEQRA Supplemental Findings Statement is attached to this order as Appendix E. The actions adopted in this order do not alter or impact the findings statements issued previously. Neither the nature nor the magnitude of the potential adverse impacts will change as a result of this order. Rather, through this order, the Commission has taken concrete steps to transform New York's electric grid into a modern, distributed and increasingly clean system, consistent with the goals of the REV initiative.

SUMMARY OF DECISIONS

The Discussion Section offers a full explanation of the Commission's decisions in this order, including the reasons that recommendations from the Staff Proposal and from stakeholder comments are adopted, modified, or rejected. To ensure that the Commission's decisions are clearly identified for the benefit of Staff, active parties and interested stakeholders, the major decisions are summarized in this section.

This order directs an immediate transition from NEM to a VDER Phase One tariff. Projects interconnected prior to the date of this order will retain NEM compensation unless and until their owners opt-in to the VDER Phase One tariff. The VDER Phase One tariff includes two components: Phase One NEM and the Value Stack tariff. Mass market projects interconnected before January 1, 2020, subject to further limitations described below, will be compensated based on Phase One NEM. RNM, large on-site, and CDG projects for which, within 90 business days of this order, 25% of interconnection costs have been paid or a Standard Interconnection Contract has been executed if no such payment is required will be compensated based on Phase One NEM, with CDG subject to further limitations described below. RNM, large on-site, and CDG projects that do not qualify for Phase One NEM will be compensated based on the Value Stack tariff.

A. Transition from NEM to Phase One NEM

To effectuate an immediate transition away from NEM, NEM compensation under PSL §66-j will no longer be available to new projects after the date of this order. Projects that either are in service or that have completed Step 8 of the Standard Interconnection Requirements (SIR) for projects larger than 50 kW or Step 4 of the SIR for projects smaller than 50 kW by the close of business on March 9, 2017 will receive NEM based on existing tariffs; all other projects will receive service based on the VDER Phase One tariff. In order to demonstrate that Step 8 of the SIR for large projects or Step 4 of the SIR for small projects was completed by March 9, 2017, customers must provide written notification of complete installation to the interconnecting utility, as required by Step 9 of the SIR for large projects and Step 5 of SIR for small projects, by March 17, 2017. New wind projects will be eligible to receive NEM pursuant to PSL §66-l until the caps described in that statute are reached, and will then be transitioned onto the then-applicable compensation mechanism. Projects compensated under NEM will be able to opt-in to the Phase One Value Stack tariff.

B. Phase One NEM

Phase One NEM will be available to projects that interconnect or make a defined financial commitment within 90 business days of this order. CDG projects eligible for Phase One NEM are further subject to the availability of by-utility MW capacity allocations, summarized below. New mass market, on-site projects will be eligible for Phase One NEM until the earlier of January 1, 2020 or a subsequent Commission order addressing such projects in this proceeding. The deployment of mass market projects under Phase One NEM will be monitored to ensure that these projects do not create the potential for unreasonable impacts on non-participants based upon a MW capacity allocation for each utility that provides for continued opportunity under the VDER Phase One tariff. Utilities will provide frequent and transparent reporting on the progress under the MW capacity allocation and will provide notice upon hitting 85% of the allocation amount so that the Commission may consider what action is appropriate.

Phase One NEM is identical to NEM, except that projects eligible for Phase One NEM will be subject to a compensation term length of 20-years from their in-service date and will have the ability to carry-over excess credits to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects compensated under Phase One NEM will be able to opt-in to the Phase One Value Stack tariff. Projects, other than mass market on-site projects, compensated under Phase One NEM must be equipped with utility metering capable of recording net hourly consumption and injection.

C. The Value Stack

Under Phase One, the Value Stack tariff will only be available for technologies and projects that are eligible for NEM; other DER technologies will be addressed in subsequent Phases. The Value Stack tariff shall be based on monetary crediting for net hourly injections. Excess credits will be eligible for carry-over to subsequent billing and annual periods, subject to further stipulations as detailed in the Discussion Section. Projects eligible for the Value Stack tariff will receive compensation for a term of 25-years from their in-service date. Projects under the Value Stack tariff must be equipped with utility metering capable of recording net hourly consumption and injection.

Compensation under the Value Stack for net hourly injections will be calculated based on the value associated with: 1) Energy Value, based on the Day Ahead hourly zonal locational-based marginal price (LBMP), inclusive of losses; 2) Capacity Value, based on retail capacity rates for intermittent technologies and the capacity tag approach for dispatchable technologies based on performance during the peak hour in the previous year; 3) Environmental Value, based on the higher of the latest CES Tier 1 Renewable Energy Certificate (REC) procurement price published by NYSERDA or the Social Cost of

Carbon (SCC); and 4) Demand Reduction Value (DRV) and Locational System Relief Value (LSRV), based on a deaveraging of utility marginal cost of service (MCOS) studies, performance during the 10 peak hours, and further process as detailed in the Discussion Section. In addition, utilities are directed to develop options for a fee-based portfolio service under which DG projects can be aggregated into a virtual generation resource.

CDG projects compensated under the Value Stack tariff will be eligible for an MTC, equal to the difference between the "Base Retail Rate" and "Estimated Value Stack" as detailed below in the Discussion Section. CDG projects will receive a pro-rata MTC based on the portion of their project that is dedicated to serving small customers and shall not receive a DRV for that portion of their project. Eligibility for MTC compensation will be subject to the availability of MW capacity allocations in each utility that are derived from the incremental 2% net revenue impact limitation, summarized below.

MW capacity is further allocated to three distinct Tranche buckets as follows: Tranche 0 (Phase One NEM)/Tranche 1 (Value Stack plus MTC equal to 100% Base Retail Rate); Tranche 2 (Value Stack plus MTC equal to 95% Base Retail Rate; Tranche 3 (Value Stack plus MTC equal to 90% Base Retail Rate). The specific method and allocations to distinct Tranches is further detailed below under the Discussion Section and in Table 2. After 90 business days from the date of this order, any remaining capacity in Tranche 0 shall be rolled over to Tranche 1. Utilities will provide frequent and transparent reporting on the progress of Tranches and will provide notice upon hitting 85% of the total allocation amount so that the Commission may consider what action is appropriate. Eligibility for placement in a Tranche will be based on the time-stamp of a 25% advanced payment for interconnection upgrade costs or execution of a

Standard Interconnection Contract if no such payment is required.

D. Managing Potential Impacts on Non-Participants

To manage the potential impacts of the VDER Phase One tariff on non-participants, an incremental net annual revenue impact of approximately 2% for each utility will be established for all projects interconnected after the date of this order. The 2% upper bound will not result in a hard cap, but instead is used to design capacity-based allocations for mass market and CDG projects.

E. Cost Allocation Principles

Costs associated with compensation under the VDER Phase One tariff will be collected, proportionately, from the same group of customers who benefit from the savings associated with the compensated DER. For compensation that does not reflect a value that has been identified and calculated at this time, recovery will come from customers within the same service class as the beneficiaries.

F. Inclusion of Energy Storage

A Project that include energy storage paired with an eligible resource will be eligible for compensation under NEM, for mass market on-site projects, or the VDER Phase One tariff. As part of the development of the final Value Stack tariff, Staff will consider whether there are alternatives to their recommendation to base compensation on net monthly injections in order to better reflect actual storage configurations and value while still avoiding uneconomic arbitrage. The application of the Phase One tariff to stand-alone storage facilities will be addressed in subsequent phases.

G. Mitigation of Bill Impact and CDG Project Costs

Staff is directed to work with NYSERDA, the utilities, and market participants to develop and file a proposal for next steps that can be taken to reduce, eliminate or mitigate market barriers, bill impacts or CDG project costs. Topics include: development costs, consolidated billing, customer maintenance costs, and interconnection costs.

H. Enabling Participation of Low-Income Customers in VDER Programs and Tariffs

The Commission directs Staff to work with utilities and interested stakeholders to consider an interzonal CDG credit program designed to provide benefits from CDG projects interconnected in service territories and load zones other than that of the low-income participant. The Commission also supports NYSERDA's continued investigation into enabling low-income customer participation in CDG projects, and directs NYSERDA to file CEF investment chapters to support programs aimed to encourage and incentivize low-income participation in CDG projects. Finally, the Commission directs Staff to consider options to encourage low-income participation in CDG under the VDER Phase tariffs, including tailored approaches for CDG projects that comprise a majority of low-income off-takers.

I. Oversight of DER Providers

Given the advancement of this and other proceedings since the filing of the initial DER Oversight Staff Proposal on July 28, 2015, the Commission directs Staff to develop an updated whitepaper that will be issued for public comment within thirty days such that the Commission will be able to consider the DER oversight provisions at the same time as it acts on the implementation issues in this proceeding.

J. Further Process

To enable the full implementation of the Value Stack tariff, the utilities are directed to make specific filings, following engagement with Staff and stakeholders, to enable public comment and Staff consideration such that the Commission may consider a Value Stack Implementation order as soon as Summer 2017. While a full listing of items appears in the Discussion Section, particular items of note include filing by each utility of: tariff leaves for implementing Phase One NEM; proposed implementation of cost allocation principles; proposed method and values for capacity; the most recent MCOS studies and workpapers followed by specific DRVs and LSRVs along with identification of specific locations and MW caps for LSRVs; MTC values; and a work plan and timeline for developing locationally granular prices to reflect the value to a utility's distribution system from DER additions.

K. Commencement of VDER Phase Two

Phase Two will commence in May 2017 with a procedural conference or other meeting of interested parties. An agenda will be issued at least five days in advance of the meeting. Specific topics to be addressed and prioritized in Phase Two are discussed further under the Discussion Section of this order.

DISCUSSION

I. THE NEED FOR TRANSITION

Through the REV initiative, the Commission has taken concrete steps to transform New York's electric grid into a modern, distributed, integrated, transactive, and increasingly clean system. This order addresses a fundamental requirement of building a distributed grid and offering fair and accurate compensation to all market participants: compensation of DER for the values they create. The REV initiative, through which the Commission is pursuing a consumer-centric, economically efficient, and environmentally sustainable energy future, demands accurate valuation of and compensation for DER. REV's tariff without sufficient consideration of their divergent attributes could lead to unintended consequences.

However, as commenters note, it is a key principle of REV that regulation and tariffs should be technologically neutral and focus on values provided and costs imposed by a DER and their behavior. Therefore, as part of Phase 2, VDER tariffs will be expanded beyond NEM-eligible DG technologies to all DER in a technologically-neutral, value-focused manner as soon as practicable.

B. Inclusion of Energy Storage

1. Staff Proposal

The Staff Proposal notes that energy storage technologies, such as batteries, are not addressed in PSL §§ 66-j or 66-l and recommends that storage be included in Phase One. Specifically, Staff recommends that: 1) projects that pair any energy storage technology with an eligible generation facility, including for the purposes of exporting stored energy, should be permitted to receive compensation under the Phase One tariff; 2) mass market and small wind systems that include storage should be permitted to retain NEM compensation; 3) for CDG, RNM, and large on-site systems, the installation of storage should require participation in the Value Stack, rather than NEM; 4) the presence of energy storage should not result in any change in compensation except that compensation for environmental value and the MTC should only be provided for net monthly exports; and; 5) while the use of system power to charge storage should be permitted, and even encouraged to the extent that it can support the system by reducing peak demand and variability, environmental and MTC compensation should not be provided for the export of stored system power.

The Staff Proposal also suggests that NYSERDA and the utilities examine solar-plus-storage intervention and demonstration strategies that can help to further monetize system value, especially in high value locations of the distribution system, as VDER Phase One tariffs are implemented. Lastly, Staff recommends that projects that include energy storage but no eligible generator should not be eligible for the VDER Phase One tariff at this time but that a methodology for their inclusion should be developed for implementation at or before Phase Two.

2. Comments

Many commenters, including AEEI and NY-BEST, support Staff's recommendation to include energy storage paired with eligible generators under Phase One noting the importance of energy storage under REV. AEEI, Borrego and SolarCity also stress the importance of taking up consideration of stand-alone energy storage and recommend this topic as a priority; EDF/Policy Integrity suggest that a clear roadmap for doing so, with consideration by the Commission in 2017, is necessary. NY-BEST and TASC are particularly supportive of the solar-plus-storage intervention that is currently being considered by NYSERDA. SolarCity argues that solar projects paired with storage should be permitted to both provide on-site demand and load reduction and export under the VDER tariff. SolarCity also argues that large, on-site projects paired with energy storage should be able to charge on mandatory-hourly pricing even if the customer is not on this pricing scheme; AEEI agrees.

CORE, EDF/Policy Integrity, and Pace comment that Staff's recommendation to provide environmental value only to net exports from facilities paired with energy storage is insufficient to capture the full environmental values associated with energy storage, including the value of shifting load from dirty to less dirty generation on the bulk system. CORE suggests that the environmental value associated with energy storage should be equivalent to how other clean generation is compensated for environmental value under VDER, which will help to encourage energy storage and further the State's clean energy goals.

3. Determination

The Commission adopts Staff's proposal to include energy storage when paired with an eligible VDER resource. Consistent with that proposal, mass market customers that include storage in their on-site systems will be permitted to retain NEM or Phase One NEM; however, customers that wish to pair storage with a CDG, RNM, or large on-site system will be required to receive compensation based on the Value Stack. While Staff's proposal limited the environmental and MTC compensation for energy storage to net monthly injections to avoid inappropriately providing compensation for those elements for non-green energy stored and then discharged, we recognize that such restrictions may not be reflective of expected storage installation configurations. Because of current federal tax credit rules, most energy storage systems are only charged with renewable power, and therefore the net monthly injection restriction may be unnecessary. Furthermore, the restriction could result in customers with significant usage, clean generation, and energy storage behind a single meter receiving compensation for less environmental value than they actually provide. Staff shall work with stakeholders to identify an alternate option for consideration by the Commission in implementing the Value Stack, such as a commitment by the customer to only charge using the eligible VDER resources, that still avoids uneconomic arbitrage while better reflecting actual storage configurations and value.

As the Staff Proposal and commenters acknowledge, energy storage is a key component of our energy future. The integration of storage into DER deployments and the utility system has the potential to substantially enhance DER's capability to lower system costs and provide a variety of energy services. In addition to working to include stand-alone energy storage projects within the VDER Phase One tariff as expeditiously as possible, other methods of further encouraging integration of storage, including non-wires alternative projects and demonstration projects, are addressed in the Commission's order regarding Distributed System Integration Plans (DSIPs) considered at the same session as this order.

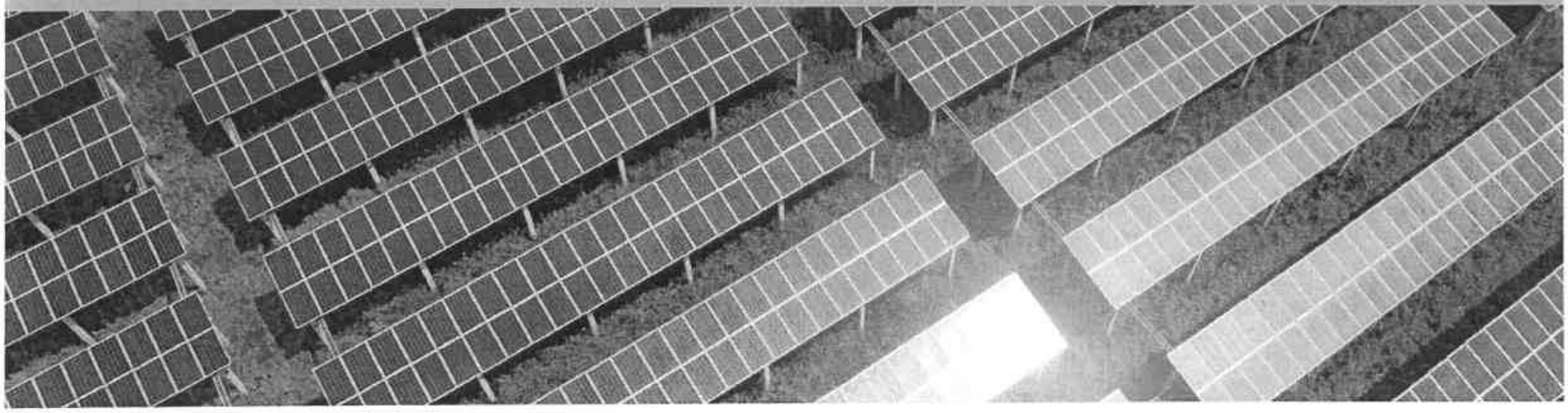
As noted in the Staff Proposal, NYSERDA is developing approaches to accelerating solar-plus-storage applications through the CEF. Staff shall work with NYSERDA and market participants to develop an Energy Storage Roadmap that identifies current and anticipated electric system needs that energy storage is uniquely suited to address, levels of energy storage that provide net benefit to ratepayers, and market-backed policies, consistent with REV objectives, to build energy storage in New York State.

While commenters' observation that projects that include energy storage could offer certain environmental benefits not recognized in the current Value Stack tariff, such as shifting energy consumption to a time of day when incremental generation is cleaner, is accurate, those benefits may not provide a cost savings to utilities and are not calculable at this time. As discussed further below, as part of Phase Two of this proceeding Staff and interested stakeholders should work to consider whether and how more granular values, including environmental benefits from time-shifted consumption, can be included in VDER tariffs.

Exhibit 4

The Value Stack

Compensation for Distributed Energy Resources



REDUCE
carbon footprint

MANAGE
solar energy development

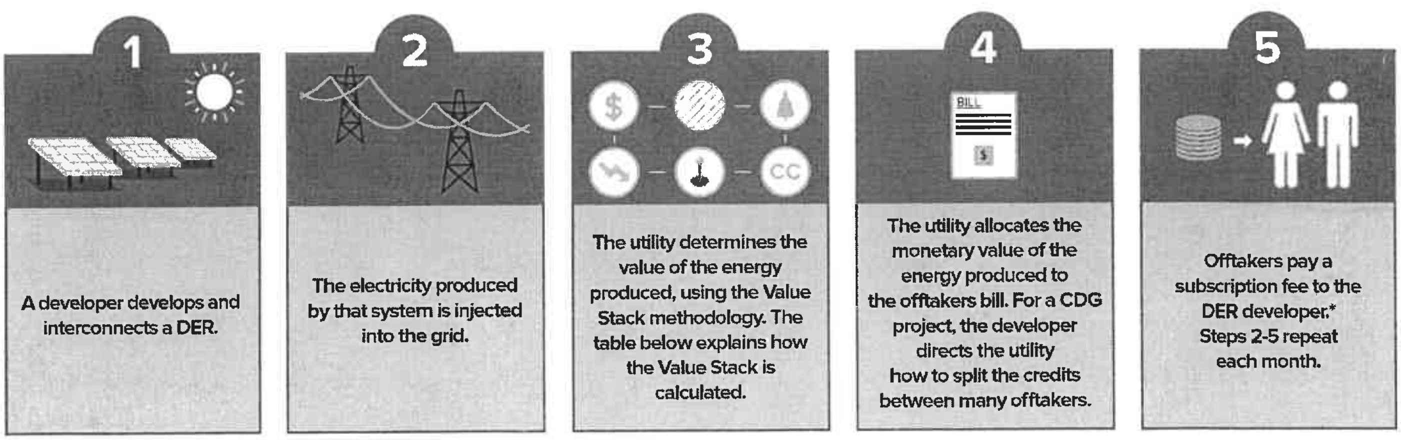
CREATE
cleaner communities

visit:
nyserda.ny.gov/vder

Accurate, fair, and bankable compensation

The Value of Distributed Energy Resources (VDER), which includes the Value Stack, is a methodology or tariff used to compensate energy created by distributed energy resources (DERs). Compensation under the Value Stack is based on the actual benefits a resource provides to New York's electric grid and is in the form of bill credits. This is determined by a DER's energy value, capacity value, environmental value, demand reduction value, and locational system relief value. The Value Stack methodology applies to onsite non-residential projects larger than 750 kilowatts AC and all remote metered projects including those using a Community Distributed Generation (CDG) configuration. Eligible technologies include solar photovoltaics (PV), stand-alone and co-located energy storage, certain types of combined heat and power (CHP), anaerobic digesters, wind turbines, small hydro and fuel cells.

How the Value Stack works



*Currently, the offtaker will receive a separate bill from the developer. Under consolidated billing, the payment will be made by the utility to the developer "behind the scenes" and offtakers will only see their single electric bill.

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Key ideas

- Starting in March 2017, New York State began a transition away from net metering to the Value Stack.
- The Value Stack was developed with robust feedback from utilities, project developers, and other external stakeholders to ensure an accurate and fair compensation model to provide project owners and developers with reasonable revenue certainty and bankability.
- The Value Stack compensates energy producers with monetary credits. Offtakers (customers receiving the bill credits from a DER) will see a dollar credit on their electric bill.

How the Value Stack is calculated

Value Name	Description	Eligible DERs
Energy Value (LBMP)	LBMP is the day-ahead wholesale energy price as determined by NYISO. It changes hourly and is different according to geographic zone.	All technologies: PV, storage, CHP, digesters, wind, hydro, and fuel cells.
Capacity Value (ICAP)	ICAP is the value of how well a project reduces New York State's energy usage during the most energy-intensive days of the year. Developers can choose from three payout alternatives and most ICAP rates change monthly.*	All technologies receive ICAP. Dispatchable technologies (stand-alone storage, CHP, digesters, and fuel cells) will receive Alternative 3.
Environmental Value (E)	E is the value of how much environmental benefit a clean kilowatt-hour brings to the grid and society. The E value is locked in for 25 years.**	PV, wind, hydro, and storage charged exclusively from PV or wind energy. Stand-alone storage is not eligible at this time.
Demand Reduction Value (DRV)	DRV is determined by how much a project reduces the utility's future needs to make grid upgrades. DRV is locked in for 10 years.**	All technologies.
Locational System Relief Value (LSRV)	LSRV is available in utility-designated locations where DERs can provide additional benefits to the grid. Each location has a limited number of MW of LSRV capacity available. The LSRV is locked in for 10 years.**	All technologies. Project must be on a utility-specified substation.
Community Credit (CC)	CC is available on a limited basis to encourage the development of Community Distributed Generation (CDG) projects. CC is the successor to the Market Transition Credit (MTC) and is similar in structure. The CC is locked in for 25 years.** PV projects in utility territories that have fully expended their CC may be eligible for the Community Adder – an upfront incentive administered by NY-Sun.	Available for CDG projects including PV and digesters. Wind, hydro, and fuel cells receive CC at a derated value. Not available for stand-alone storage or CHP.

**For more information on the three ICAP alternatives, view the most recent Value Stack presentation slides on the Value Stack Resources page at nyserda.ny.gov/value-stack-resources*

***Projects will lock in their E, DRV, LSRV, and CC values when they make their 25% upgrade payment to the utility. If no utility upgrade costs are required, the values are locked in when the interconnection agreement is fully executed.*

Find additional information and access resources to help you.

- **Solar Value Stack Calculator** – Better estimate compensation for specific solar jobs: nyserda.ny.gov/value-stack-calculator
- **Stand-alone Storage Value Stack Calculator** – Estimate compensation for stand-alone storage projects in Con Edison's service territory: nyserda.ny.gov/storage-technical-assistance
- **Value Stack Historic Data and Rates** – Find compiled rates updated monthly by the New York State Department of Public Service (DPS): nyserda.ny.gov/vder

Exhibit 5

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators

Applicable to SCs 1, 2, 5, 8, 9, 11, 12, and 13

A. Applicability

1. To any residential Customer with solar electric generating equipment located and used at the Customer's residence, provided the equipment has a rated capacity of not more than 25 kW unless the residence is also the location of the Customer's Farm Operation, in which case the equipment may have a rated capacity of not more than 100 kW;

2. To any Customer with farm waste electric generating equipment (as defined in Public Service Law Section 66-j) with a rated capacity of not more than 2,000 kW, provided such equipment is located and used (a) at the Customer's Farm Operation or (b) at the Customer's non-residential premises that is not its Farm Operation ("Non-farm Location");

3. To any non-residential Customer with solar electric generating equipment or wind electric generating equipment with a rated capacity of not more than 2,000 kW located and used at its premises;

4. To any residential Customer with wind electric generating equipment located and used at his or her primary residence, provided the equipment has a total rated capacity of not more than 25 kilowatts unless the primary residence is also the location of the Customer's Farm Operation, in which case the equipment may have a total rated capacity of not more than 500 kW, as specified in Public Service Law Section 66-l;

5. To any residential Customer with micro-combined heat and power ("micro-CHP") generating equipment (as defined in Public Service Law Section 66-j) located and used at the Customer's premises, provided such equipment has a rated capacity of at least 1 kW and not more than 10 kW and meets the requirements specified in Public Service Law Section 66-j and in the Standardized Interconnection Requirements;

6. To any Customer with fuel cell electric generating equipment (as defined in Public Service Law Section 66-j) located and used at the Customer's premises, provided (a) in the case of a residential Customer, such equipment has a rated capacity of not more than 10 kW, or (b) in the case of a non-residential Customer, such equipment has a rated capacity of not more than 2,000 kW;

7. To any Customer with micro-hydroelectric ("micro-hydro") generating equipment located and used at the Customer's premises, provided (a) in the case of a residential Customer, such equipment has a rated capacity of not more than 25 kW, or (b) in the case of a non-residential Customer, such equipment has a rated capacity of not more than 2,000 kW;

8. To any Customer: (a) with the generating equipment described above in A.1, A.2, A.3, A.4, A.6, and A.7 with a rated capacity greater than the rated capacities listed, up to 5,000 kW; (b) with a Hybrid Facility consisting of Electric Energy Storage where all of the other eligible electric generating equipment is the equipment described in A.1-A.7 up to the rated capabilities listed in A.1-A.7 by customer type; or (c) with a Hybrid Facility consisting of Electric Energy Storage where all of the other eligible electric generating equipment co-located on the account is the equipment described in A.1, A.2, A.3, A.4, A.6, or A.7 with a rated capacity greater than the rated capacities listed, up to 5,000 kW; and

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

Applicable to SCs 1, 2, 5, 8, 9, 11, 12, and 13

A. Applicability - Continued

9. Customers with: (a) biomass electric generating equipment rated up to 5,000 kW as defined in the NYSERDA Clean Energy Standard Tier 1 eligibility criteria, including biogas and liquid biofuel, with an in-service date after January 1, 2015; (b) tidal/ocean electric generating equipment rated up to 5,000 kW as defined in the NYSERDA Clean Energy Standard Tier 1 eligibility criteria, with an in-service date after January 1, 2015; (c) generating equipment rated up to 5,000 kW listed in (a) and (b) as a resource ineligible for Clean Energy Standard Tier 1 solely by virtue of having an in-service date prior to January 1, 2015; (d) Stand-alone Electric Energy Storage for any hourly injection into the grid; and (e) a Hybrid Facility consisting of Electric Energy Storage and at least one of the eligible electric generating equipment types described in (a) – (c). Such Customers taking service under Section A.9 of this Rider must also take service under SC 11.

Options A.1 – A.8 are not available to Customers who take service under SC 11.

The kW of facilities with generating equipment located near each other will be aggregated to determine if the kW limit is met unless each facility meets all of the following criteria: (a) each project up to the respective generating size limit must be separately metered and separately interconnected to the Company's grid; (b) 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) or Borough-Block-Lot (BBL) number, a separate lease, and a separate metes and bounds description recorded via either a deed or separate memorandum of lease uniquely identifying each project; and (c) each project must operate independently of the other units. The aggregated rated capacity of electric generating equipment shall be limited to 25 kW for residential Customers served under Grandfathered Net Metering or Phase One NEM, 2,000 kW for non-residential Customers served under Grandfathered Net Metering or Phase One NEM, and 5,000 kW for Customers served under the Value Stack Tariff. The Company will waive the 2,000 kW limit for a Grandfathered Net Metering or Phase One NEM Customer whose solar electric generating facility successfully participated in the NYSERDA – Competitive Solar PV Solicitation: Program Opportunity Notice ("PON") 2589, PON 2860, or PON 2956 or the New York City Department of Environmental Protection and Economic Development Corporation's March 2, 2012 Request for Proposals ("RFP") if the Customer demonstrates that the PON or RFP participant made good faith efforts to comply with the 2,000 kW limit in configuring its proposal.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

A. Applicability – Continued

Under no other circumstances shall a project larger than 2,000 kW receive compensation based on Grandfathered Net Metering or Phase One NEM. Electric generating equipment as described in paragraph A.2, A.3, A.6.b. and A.7.b. is eligible for Value Tariff Stack compensation for equipment with a rated capacity greater than 2,000 kW and not more than 5,000 kW pursuant to the Commission's Order issued February 22, 2018 in Case 15-E-0751. Electric generating equipment as described in paragraph A.8 and A.9 is eligible for Value Stack Compensation pursuant to the Commission's Order issued September 12, 2018 in Cases 15-E-0082 and 15-E-0751.

Service will be provided under this Rider to Customers with eligible electric generating equipment (as described above), subject to the provisions of this Rider, including the term of service specified in Section K, as follows:

Grandfathered Net Metering

Grandfathered Net Metering is applicable to Customers that have:

1. non-wind electric generating equipment, up to an aggregate of 156,609 kW of total rated generating capacity, for projects that were served by the Company under Public Service Law Section 66-j as of the close of business on March 9, 2017, including projects for which Step 4 of the SIR (for generation rated 50 kW or less) or Step 8 of the SIR (for generation rated above 50 kW) was completed by close of business on March 9, 2017; or

2. wind electric generating equipment, up to an aggregate of 33,246 kW of wind generating capacity served under Grandfathered Net Metering.

The kW limit on non-wind electric generating equipment will automatically decrease as non-wind projects served under PSL Section 66-j are taken out of service, but will not decrease below 110,802 kW.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

A. Applicability – Continued

Phase One Net Metering ("Phase One NEM")

Phase One NEM is applicable to Customers not eligible for Grandfathered Net Metering that are:

1. Large On-Site Customers or Customers with the electric generating equipment described in A.2, A.3, A.6, and A.7 that is located on the premises of an RNM Host Account or CDG Host Account (up to 137,000 kW of total rated generating capacity of CDG Hosts served under Phase One NEM); provided that 25 percent of interconnection costs have been paid on or before July 17, 2017, or an SIR contract has been executed on or before July 17, 2017, if no such payment is required; or

2. Large On-Site Customers with electric generating equipment described in A.2, A.3, A.6, and A.7 that has a rated capacity of 750 kW AC or lower and has an estimated annual output less than or equal to 110% of that Customer's historic annual usage in kWhr. Service under this provision will commence with the Customer's first bill having a "from" date on or after June 1, 2019 unless they choose to opt-in to the Value Stack Tariff.

3. Mass Market Customers with the electric generating equipment described in A.1 – A.7 that is placed in service after March 9, 2017 .

Customers with projects listed under (A)(3) above with electric generating equipment that is interconnected on or after January 1, 2022 will be subject to the Customer Benefit Contribution ("CBC") Charge described in Section I of this Rider. Customers with projects listed under A.2 and A.3 above with electric generating equipment that is interconnected on or after January 1, 2022 shall be permitted to elect a different rate option from the rate options available to the Customer under their service classification (e.g., non-TOD, TOD, or Standby Service, if available) once per year on their selected anniversary date; however, should the Customer elect Standby Service rates, the Customer will receive compensation under the Value Stack Tariff and will no longer be eligible for Phase One NEM.

In the event that a single project causes an exceedance of the 137,000 kW threshold for CDG Host Accounts, the project will qualify for Phase One NEM; however; the kW above the 137,000 threshold will be counted as kW under the Value Stack Tariff.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

A. Applicability – Continued

Value Stack Tariff

The Value Stack Tariff is applicable to Customers not eligible for Grandfathered Net Metering or Phase One NEM; provided, however, that Customers served under either Grandfathered Net Metering or Phase One NEM will be provided a one-time, irrevocable opt-in to the Value Stack Tariff. A Customer will be placed under either Value Stack Phase One or Value Stack Phase Two based on the criteria set forth below.

Value Stack Phase One applies: (1) to Customers that, on or prior to July 26, 2018, have paid at least 25 percent of their interconnection costs or executed the interconnection agreement if no such payment is required; and, (2) to Customers that have met criteria (1) and had opted into the Value Stack Tariff prior to June 1, 2019.

Value Stack Phase Two applies: (1) to Customers that, on or after July 27, 2018, have paid at least 25 percent of their interconnection costs or executed the interconnection agreement if no such payment is required; and, (2) to Customers who opt into the Value Stack Tariff on or after June 1, 2019 subject to the next paragraph.

Value Stack Phase One Customers will be provided a one-time, irrevocable opt-in for compensation under Value Stack Phase Two for all applicable Value Stack Phase Two components, unless that Customer has a CDG project that had been assigned a Tranche position on or prior to July 26, 2018. Such Customer assigned a Tranche position on or prior to July 26, 2018 shall receive compensation under Value Stack Phase One for the 25-year term from their in-service date.

Service under the Value Stack Phase Two provision will commence with the Customer's first bill having a "from" date on or after June 1, 2019.

The Company will process requests for interconnection under this Rider in accordance with the SIR. For interconnection requests made on or after December 1, 2017, for CDG projects and On-Site Mass Market Customer projects, a distributed generation provider must submit proof to the Company with its initial interconnection application that its project has been registered with Department of Public Service Staff in accordance with the UBP-DERS. The Company reserves the right to decline requests from generators to interconnect to the distribution network system when the Company deems it necessary to protect its system, facilities, or other Customers.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

A. Applicability – Continued

If there is a change in account name for the premises on which the generator is located (i.e., an RNM Host Account, an RC Host Account, a CDG Host Account, or the account of a Customer with on-site generation that does not participate in RNM, RC, or CDG), the successor Customer will be eligible for service under this Rider, subject to the Section G or Section H charges and credits applicable to its predecessor, for the remaining term of service. If there is a Customer-initiated change in the generating equipment that requires a new standardized interconnection request to be filed with the Company (e.g., due to an increase in the nameplate rating or replacement of the generating facility) or a change in the type of net metering (e.g., from CDG to RNM or from RNM or RC to a single net-metered account), the account will be subject to the applicable terms and conditions of service in effect at the time of such change.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

B. Definitions, applicable to this Rider only

"Avoided Energy Cost" refers to a calculation, determined for the NYISO load zone applicable to the Customer, equal to the Company's total energy cost with respect to the day-ahead and real-time NYISO energy markets for the specified period divided by the Company's total kWhr purchases from the NYISO for that period, based on the best available information at the time of the Company's calculation. This amount will be increased by a factor of adjustment of 1.066 for Customers taking service at the secondary distribution level.

"Community Distributed Generation" or "CDG" refers to net energy metering in which excess energy produced by a Customer's generating equipment is applied to other Customers' electric accounts pursuant to Section F of this Rider.

"CDG Host Banked Credit" refers to the unallocated credits from the Value Stack, Grandfathered Net Metering or Phase One NEM CDG Host Account that will be added to the retained credits on the CDG Host Account pursuant to Section F of this Rider.

"Farm Operation" means "farm operation" as defined in Subdivision 11 of Section 301 of the New York State Agriculture and Markets Law ("Agriculture Law"), unless the Customer uses wind electric generating equipment. "Farm Operation" means "land used in agricultural production" as defined in Subdivision 4 of Section 301 of the Agriculture Law if wind electric generating equipment is used.

"Hybrid Facility," for the purposes of this Rider, means a facility that co-locates, on the same Electric account, an Electric Energy Storage system with a Rider R eligible electric generator that is compensated under the Value Stack Tariff and has a maximum aggregate instantaneous export of no more than 5,000 kW .

"Large On-Site Customer" means a Customer billed under demand rates whose electric generating equipment supplies energy to a single account behind the same meter as the generating equipment.

"Mass Market Customer" means a Customer billed under energy-only rates whose electric generating equipment supplies energy to a single account behind the same meter as the generating equipment. Under Section H of this Rider, a Mass Market Customer means a customer taking service under SC No. 1 or SC No. 2 that is a CDG Satellite, or has opted into the Value Stack Tariff and whose electric generating equipment supplies energy to a single account behind the same meter as the generating equipment.

"Net consumption" or "Net hourly consumption" is the amount of energy consumed by a Customer from the Company's system.

"Net energy metering" measures the reverse flow of electricity so as to register the difference between the electricity supplied by the Company and the electricity provided to the Company by the Customer's generating equipment.

"Net energy" is the difference between the amount of energy supplied by the Company and the amount of energy provided to the Company by the generating equipment during a billing period.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

B. Definitions, applicable to this Rider only – Continued

"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.

"Remote Crediting" or "RC" refers to the process of applying Value Stack credits derived from the excess energy produced by a Customer's electric generating equipment to other electric accounts pursuant to Section F of this Rider. RC only applies to Value Stack Customers.

"Remote Crediting Customer" or "RC Customer" refers to a Customer participating in an RC project that can have any number of RC Satellite Accounts that are allocated credit from an RC Host Account provided, however, that all such RC Satellite Accounts are established in a common customer name and located on properties owned or leased by the Customer.

"Remote Net Metering" or "RNM" refers to net energy metering in which excess energy produced by a Customer's electric generating equipment is applied to that Customer's other electric accounts pursuant to Section F of this Rider. RNM only applies to Grandfathered Net Metering or Phase One NEM Customers.

"Residential," for purposes of this Rider, refers to service under SC 1, and "Non-residential" refers to service under any other Service Classification.

"Stand-alone Electric Energy Storage," for the purposes of this Rider, includes regenerative braking, whether or not paired with a separate battery, and Vehicle to Grid ("V2G") or Vehicle-to-Grid Integration ("VGI") systems.

C. Applications for Service

1. Customers' applications for interconnection to the Company's system will be made using the applications set forth in Addendum-SIR.

2. Assuming the conditions of the Standardized Interconnection Requirements are met, the Company and the Customer will execute the New York State Standardized Contract set forth in Addendum-SIR.

3. Customers' applications for service under this Rider for net metering or the Value Stack Tariff will be made using Application Form G in the General Rules. Applications for CDG will be made using the application form set forth in the Company's CDG Program Procedural Requirements. CDG Hosts required to take Standby Service and/or SC 11 must also complete Application Form G in addition to the application form set forth in the Company's CDG Program Procedural Requirements. Applications for CDG Net Crediting, pursuant to paragraph 3.d of Section F of this Rider, will be made in conformance with the Company's CDG Net Crediting Manual. Applications for RC must include an initial allocation request, in a format acceptable by the Company and pursuant to Section F of this Rider, in addition to completing Application Form G.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

D. Requirements for Parallel Operation

Electric generating equipment may be operated in parallel with the Con Edison system under this Rider under the following conditions:

1. The generating equipment must be designed, installed, interconnected, tested, and operated in accordance with applicable government, industry, and Company standards and must comply with the standards contained in the Standardized Interconnection Requirements.

2. The Company may install a dedicated transformer or transformers or other equipment if necessary to protect the safety or adequacy of electric service provided to other Customers. Upon the written request of the Customer, the Company will furnish within 45 days a written explanation for the Company's decision to install a dedicated transformer or other equipment. A Customer taking service under this Rider shall pay for the cost of installing such transformer or other equipment to protect the safety or adequacy of electric service provided to other Customers only up to a maximum amount, inclusive of taxes, as follows:

Electric Generating Equipment	Total Rated Capacity	Maximum Amount
Residential micro-CHP	1 to 10 kW	$350
Residential fuel cells	up to 10 kW	$350
Residential micro-hydro	up to 25 kW	$350
Solar	up to 25 kW	$350
Wind	up to 25 kW	$750
Farm waste at Farm Operation	up to 5,000 kW	$5,000
Farm wind	above 25 kW up to 500 kW	$5,000
Nonresidential solar or wind	above 25 kW up to 5,000 kW	Company's actual cost*
Non-residential fuel cells	up to 5,000 kW	Company's actual cost *
Non-residential micro-hydro	up to 5,000 kW	Company's actual cost *
Non-residential farm waste at non-farm Location	up to 5,000 kW	Company's actual cost*
All other Electric Generating Equipment and Rating Capacities Served Under this Rider		Company's actual cost*

*Actual cost applies unless otherwise specified in the SIR.

The Customer will not unreasonably refuse the Company's request to install a dedicated transformer on the Customer's premises and will cooperate with the Company to facilitate such installation in a cost effective manner. If a dedicated transformer cannot be installed in a cost effective manner or if the dedicated transformer(s) or other equipment does not satisfactorily ameliorate the concerns prompting its installation, the Customer is responsible to implement such additional measures as required to satisfactorily ameliorate the concerns as a condition for continued service under this Rider.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

D. Requirements for Parallel Operation - Continued

3. Generation equipment interconnected to the Company's distribution system must be installed, interconnected, tested, and operated in accordance with applicable Company standards, which are not to be inconsistent with the Standardized Interconnection Requirements.

4. [RESERVED FOR FUTURE USE]

5. In addition to the costs set forth in Section D.2, Customers may be required to contribute to interconnection costs, as described in the SIR. The Customer may also be responsible for the costs of Interval Metering and the telecommunications service as described in Section E of this Rider.

   The costs of interconnection include the costs of initial engineering evaluations, switching, metering, transmission, distribution, safety provisions, engineering, administrative costs, and any associated tax expenses incurred by the Company directly related to the installation of the facilities deemed necessary by the Company to permit interconnected operations with a Customer, to the extent such costs are in excess of the corresponding costs which the Company would have incurred had the Customer not taken Standby Service under the Service Classification that would have otherwise been applicable to the Customer. All such facilities will remain the property of the Company.

6. The Customer will not be responsible for any other costs to the Company to interconnect its system to the Customer's generation equipment other than the costs specified hereunder and in the Standardized Interconnection Requirements.

7. The Customer must permit the Company to enter the property, without notice when necessary, in the event the Customer's generation equipment malfunctions and entry is necessary to protect the public safety or preserve system reliability.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

D. Requirements for Parallel Operation - Continued

8. Except as specified in General Rules 8.1 and 8.2 of this Rate Schedule, if there is a generator on the premises in addition to the electric generating equipment eligible for net metering or the Value Stack Tariff, the Customer will not qualify for service under this Rider unless the Customer segregates the additional equipment and associated load so that it is not served under this Rider. If a Customer has solar, wind, and/or micro-hydro electric generating equipment as well as micro-CHP and/or fuel cell electric generating equipment, the Customer will qualify for service under Grandfathered Net Metering or Phase One NEM only if the load served by the residential micro-CHP and/or fuel cell electric generating equipment is not served under the same net-metered account as the load served by the solar, wind, and/or micro-hydro electric generating equipment. If a non-residential Customer has farm waste electric generating equipment as well as solar, wind, and/or micro-hydroelectric generating equipment at its Non-farm Location, the Customer will qualify for service under Grandfathered Net Metering or Phase One NEM only if the load served by the farm waste electric generating equipment is not served under the same net-metered account as the load served by the solar, wind and/or micro-hydroelectric generating equipment.

   Mass Market Customers may qualify for service under Grandfathered Net Metering or Phase One NEM if there is Electric Energy Storage on the premises in addition to the electric generating equipment eligible for net metering. All other Customers with a Hybrid Facility will qualify for service under the Value Stack Tariff. Customers with a Hybrid Facility described in Section A.9 of this Rider will be subject to Standby Service and Standby Service Rates, as applicable.

9. Prior to commencing service under this Rider, a Customer with micro-CHP generating equipment must submit technical documentation, acceptable to the Company, establishing that the equipment meets the requirements specified in Public Service Law Section 66-j and in the Standardized Interconnection Requirements. No more than once annually thereafter, the Company may require the Customer to submit technical documentation establishing continued eligibility. A Customer who fails to provide documentation acceptable to the Company within 30 days of a Company request will be deemed ineligible to participate under this Rider until the first billing cycle commencing after acceptable documentation is received.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

E. Metering

1. The Company will employ net energy metering to measure and charge for the net energy supplied by the Company.

    a. If: (1) the customer requests metering equipment that is not required by the Company; (2) the customer requires multiple meters in accordance with the SIR to be eligible to receive compensation under Section H.5 of this Rider; or (3) the customer makes a one-time election to change from Option H.5.b.(i), or H.5.b.(ii) to H.5.b.(iii) of this Rider requiring additional meters or other equipment to accommodate the change, such metering equipment shall be installed at the Customer's expense.

    b. If the Customer is billed under demand rates, the Company will select a metering configuration that enables it to credit the Customer for the kWhr supplied to the Company by the Customer and measure the peak kW delivered by the Company to the Customer.

2. Large On-Site Customers, RNM Host Accounts, RC Host Accounts, and CDG Host Accounts are required to have Interval Metering with telecommunications capability for service under either Phase One NEM or the Value Stack Tariff. Mass Market Customers are required to have Interval Metering with telecommunications capability for service under the Value Stack Tariff. If Interval Metering is not required for billing under the Customer's Service Classification or if Interval Metering cannot be provided through the Company's deployment of AMI meters, the Customer shall be responsible for the installation of the meter upgrade at the cost described in General Rule 17.6 and shall provide and maintain the communications service pursuant to General Rule 6.5.

3. As provided in General Rule 7.1, the Customer shall furnish, install, and maintain all meter equipment (except meters and metering transformers) and meter wiring. The Company will install the metering necessary to obtain the data required to credit the Customer for the kWhr and/or kW supplied to the Company.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation

1. Remote Net Metering

Remote Net Metering ("RNM") is only applicable to Grandfathered Net Metering and Phase One NEM Customers. Customers who take service under this Rider may apply for RNM if: (a) they are non-residential Customers; or (b) they are residential Customers with Farm Operations that have farm waste, wind, solar, micro-hydroelectric, or fuel cell electric generating equipment.

Remote Net Metering is subject to the following conditions:

a. The account for electric service at the premises where the electric generating equipment is located shall be designated the "RNM Host Account." The account(s) to which net energy is applied shall be designated the "RNM Satellite Account(s)." All RNM Satellite Accounts must be located in the same NYISO zone as the Host Account and within the Company's service territory. An RNM Satellite Account must be metered if the RNM Host Account is served under Grandfathered Net Metering, unless such RNM Host Account makes a one-time, irrevocable opt-in to the Value Stack Tariff. An RNM Satellite Account served by a Phase One NEM RNM Host Account may be unmetered provided the RNM Satellite Account receives monetary credits. The RNM Satellite Account shall not take service under SC 11 nor be billed under Standby Service rates. If a customer is served under Special Provision 8 of the PASNY Rate Schedule, the Customer may designate an RNM Satellite Account only for requirements in excess of that served under the PASNY Rate Schedule.

b. The RNM Host Account and RNM Satellite Account(s) shall be established in the same Customer name and located on property owned or leased by the Customer. The Company reserves the right to require the Customer to prove that the properties served by the RNM Host Account and all RNM Satellite Accounts are owned or leased by the same Customer.

c. The Customer shall designate in its initial application for remote net metered service the RNM Host Account and RNM Satellite Account(s) that will be remote net metered. The Customer may designate additional RNM Satellite Accounts or remove existing RNM Satellite Accounts once per year, with the new designations to take effect commencing with the January bill issued on the RNM Host Account. The Customer shall designate whether all or a portion of any net energy credit remaining after being applied to the RNM Host Account's bill shall be applied to the RNM Satellite Account(s).

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

1. Remote Net Metering - Continued

   d. An RNM Satellite Account may have more than one RNM Host and may also be a net-metered customer-generator; provided, however, that the RNM Satellite cannot also be an RNM Host. The aggregate rated capacity of generating equipment of the RNM Host Account(s) designated to serve an RNM Satellite plus the rated capacity of net-metered generating equipment on the RNM Satellite Account, if any, cannot exceed 2,000 kW.

   e. If a Grandfathered Net Metering or Phase One NEM RNM Satellite Account is also a net-metered Customer-generator, charges and credits will first be determined pursuant to paragraphs G.2.a. and G.2.b. of this Rider. RNM credits will then be applied pursuant to paragraph G.2.c.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

2. Remote Crediting

Customers who take service under this Rider may apply to be a Remote Crediting ("RC") Host Account if: (a) they are non-residential Customers; or (b) they are residential Customers with Farm Operations that have farm waste, wind, solar, micro-hydroelectric, or fuel cell electric generating equipment or Stand-alone or Hybrid Electric Energy Storage. A Customer that meets these criteria will be eligible to allocate the Value Stack credits derived from such Customer's electric generating equipment to up to ten designated RC Customers served under this Rate Schedule or the PASNY Rate Schedule, including the RC Host Account itself. The RC Host Account may allocate credits to any number of RC Customer accounts subject to the following conditions:

a. The account for electric service at the premises where the electric generating equipment is located shall be designated the "RC Host Account." The account(s) to which Value Stack credits are allocated shall be designated the "RC Satellite Account(s)." An RC Host Account may designate additional RC Satellite Accounts or remove existing RC Satellite Accounts once per billing cycle, with the new designations to take effect commencing within 30 days of the Company's receipt of the revised allocation list. The RC Host Account and all associated RC Satellite Accounts can be located in different NYISO zones within the Company's service territory as defined in General Rule No. 1. RC Satellite Accounts shall neither take service under SC 11 nor be required to be billed under Standby Service rates pursuant to General Rule 20. Each RC Satellite Account established in a common customer name and located on properties owned or leased by a common customer shall be designated as the same RC Customer for the purposes of this section.

b. All existing RNM projects that have interconnected prior to September 1, 2021, where compensation is received under Value Stack Phase One or Value Stack Phase Two will become RC projects beginning with the RC Host Account's first bill with a "from-date" on or after September 1, 2021 and shall continue to receive compensation under either Value Stack Phase One or Value Stack Phase Two, as applicable. Value Stack RNM is no longer available.

c. Each RC Host Account's aggregated rated capacity of on-site electric generating equipment is limited to 5 MW pursuant to the Commission's Order issued September 17, 2020 in Case 19-E-0735.

d. The RC Host Account shall designate in its initial application for RC service the RC Host Account and RC Customer(s) that will be remote credited along with the name and account number designating each RC Satellite Account. The RC Host Account shall allocate, on a percentage basis with up to three decimal places of accuracy, its monthly Value Stack credits to itself and/or to each of the RC Satellite Accounts such that the allocation totals 100 percent. The RC Host Account shall provide its allocation list to the Company in a manner that is acceptable to the Company. If the RC Host Account's allocation list provided to the Company totals less than 100 percent, the unallocated portion of the credits will be applied to the RC Host Account's banked credits.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

2. Remote Crediting - Continued

e. The RC Host Account may allocate to RC Satellite Accounts any portion of the RC Host Account's banked credits if written instructions are received by the Company 15 days before the RC Host Account is next billed. Any remaining available RC Host Account banked credits shall offset the RC Host Account's monthly electric charges. After offsetting the RC Host Account's electric charges, any remaining amount shall carry over on the RC Host Account's banked credits.

f. The total amount of credit allocated to an RC Satellite Account will be applied as a direct monetary credit, up to the RC Satellite Account's current electric utility bill for any outstanding energy, customer, demand, or other electric charges. Any remaining unused credit for that RC Satellite Account shall be carried over to the RC Satellite Account's next billing period pursuant to Section H.4.h of this Rider.

g. An RC Satellite Account may receive allocations from multiple RC Host Accounts and/or be a customer-generator.

(i) Such RC Satellite Accounts are limited to a cumulative total of 5 MW of installed capacity allocated to the RC Satellite Account as determined by adding the total installed on-site capacity to the allocated capacity from all RC projects in which the RC Satellite Account is a participant. The RC Host Account must certify in writing to the Company, both prior to commencing RC and annually thereafter, that it has met all program criteria set forth in the Commission's Orders, including, but not limited to, certifying that the cumulative total installed capacity of each of its RC Satellite Accounts does not exceed 5 MW. If it is determined that an RC Satellite Account is receiving more than the aggregated capacity of 5 MW, the Company shall suspend any allocation of credits to the RC Satellite Account and those credits will remain with the appropriate RC Host Account. The allocation to the RC Satellite Account will resume once the RC Satellite Account meets the 5 MW limitation.

(ii) If such RC Satellite Account has onsite generation, the Company shall first add together the current month's credits from onsite generation and any prior period excess carryover credits from the RC Satellite Account's onsite generation. This total will then be applied as a direct monetary credit to the RC Satellite Account's current electric utility bill. The remaining electric bill, if any, shall be offset by allocations to the RC Satellite Account from its RC Host Account(s).

(iii) For an RC Satellite Account participating in multiple RC projects, if the remaining electric charges, after applying any applicable onsite generation credits, are less than the allocated credits from the RC Host Accounts, the RC Satellite Account will receive credit in proportion to the associated available credit from each of the RC Host Accounts.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

2. Remote Crediting - Continued

h. – Continued

(iii) – Continued

1. After applying any onsite generation credits, if applicable, the current month's allocation from RC Host Account 1 plus any allocation from RC Host Account 1's banked credits, plus excess carryover attributed to credits previously allocated from RC Host Account 1 shall represent the total available credits from RC Host 1. The current month's allocation from RC Host Account 2 plus any allocation from RC Host Account 2's banked credits, plus excess carryover attributed to credits previously allocated from RC Host Account 2 shall represent the total available credits from RC Host Account 2 and, so forth for any other RC Host Account(s).

2. If the total available credits from all RC Host Accounts exceeds the RC Satellite Account's electric charges, less credits applied from on-site generation served under this Rider, the Company shall use a pro-rata share of credits to offset the remaining electric charges. Such pro-rata share shall be determined by calculating the relative percentage of the available credits from each RC Host Account. Total credits applied are limited to the RC Satellite Account's remaining electric charges. Any unused credit from each source (either from onsite generation or from RC Host Account(s) allocation(s) will be tracked separately on the RC Satellite Account for use in the subsequent billing period).

i. The Company will transfer any carried over credits from an RC Satellite Account to its RC Host Account banked credit when the RC Satellite Account is no longer included on its RC Host Account's allocation.

When an RC Satellite Account is closed and a credit remains after the RC Satellite Account's final bill is rendered, such credit will be returned to the RC Host Account banked credit. If an RC Satellite Account that is allocated credits from multiple RC Hosts closes, the credit associated with each RC Host Account will be returned to the RC Host Accounts' banked credit according to the available credit associated with each RC Host Account, pursuant to the calculations in provision h.(iii).1 and h.(iii).2 above.

j. Non-Value Stack RNM projects that opt into the Value Stack must adhere to the rules and requirements of Remote Crediting. Customers served under Grandfathered Net Metering or Phase One NEM must forfeit any remaining kWh credits prior to their enrollment in Remote Crediting.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation – Continued

2. Remote Crediting – Continued

   h. RC Satellite Accounts are not permitted to participate in RNM, CDG or be an RC Host Account. RC Host Accounts are not permitted to participate as an RC Satellite Account in another RC project or as an RNM Satellite Account.

   i. In-service CDG projects, whether volumetric, monetary, Value Stack, or Net Crediting, are eligible to opt into RC and vice versa subject to the rules set forth in Section F.4. of this Section and in the Commission's July 14, 2022 *Order Approving Remote Crediting Banking Rules and Addressing Switching Between Community Distributed Generation and Remote Crediting Programs,* in Case 15-E-0751.

3. Community Distributed Generation

   A "CDG Host" is defined as a non-residential Customer that owns or operates electric generating equipment eligible for net metering or the Value Stack Tariff under this Rider and whose net energy produced by its generating equipment is applied to the accounts of other electric Customers served under this Rate Schedule or under the PASNY Rate Schedule ("CDG Satellites") with which it has a contractual arrangement related to the disposition of net metering credits. A CDG Host served under this Rider with Stand-alone or Hybrid Electric Energy Storage shall take service under the Value Stack Tariff.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

   a. Applications by CDG Hosts

   The CDG Host shall designate in its initial application for CDG service the CDG Host Account and its associated CDG Satellite Accounts. The CDG Host must designate no fewer than ten CDG Satellite Accounts unless: (1) all the CDG Satellite Accounts are located on the site of the same property as the CDG Host serving residential and/or non-residential customers; or (2) the CDG project only serves CDG Satellite Accounts that are a Farm Operation as defined in Subdivision 11 of Section 301 of the Agricultural and Markets Law and residences of individuals who own or are employed by the served Farm Operation ("Farm Operation CDG Projects"). 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). The CDG Host, by submitting a completed application to the Company, is certifying that its project meets the PSC's eligibility requirements specified in its Order issued July 17, 2015, in Case 15-E-0082 and in its Order issued April 20, 2018, in Cases 15-E-0751 and 15-E-0082, and as may be revised thereafter.

   For a CDG Host Account served under Grandfathered Net Metering or Phase One NEM, the CDG Host Account and all associated CDG Satellite Accounts must be located within the same NYISO zone and within the Company's service territory. For a CDG Host Account served under the Value Stack Tariff, the CDG Host Account and all associated CDG Satellite Accounts can be located in different NYISO zones within the Company's service territory. A CDG Satellite Account shall have only one CDG Host Account either under this Rate Schedule or the PASNY Rate Schedule. A CDG Host taking service under this Rate Schedule serving any CDG Satellite Accounts taking service under the PASNY Rate Schedule must take service under the Value Stack Tariff. A CDG Satellite Account must be metered if the CDG Host Account is served under Grandfathered Net Metering, unless such CDG Host Account makes a one-time, irrevocable opt-in to the Value Stack Tariff. A CDG Satellite Account served by a non-Grandfathered Net Metering CDG Host Account may be unmetered subject to the following conditions: (1) the CDG Satellite Account receives monetary credits from a Phase One NEM CDG Host Account; (2) the CDG Satellite Account receives volumetric credits from a Phase One NEM CDG Host Account and has opted to be served under the Value Stack Tariff; or (3) the CDG Host Account and its Satellite Accounts will be served under the Value Stack Tariff. The CDG Satellite Account shall not: (1) be a net metered customer-generator; (2) be a Remote Net Metered Host or Satellite Account; (3) be an RC Host or Satellite Account; (4) take Standby Service, unless such Standby Service Customer has on-site generating equipment that has a total nameplate rating less than or equal to 15 percent of the maximum potential demand served from all sources; or (5) take service under SC 11.

   A Customer that was formerly a CDG Satellite Account may not be allocated credit from a CDG Host until the billing period after which all kWhr or monetary credits described in Sections G.2.c.(v), G.2.c.(vi) of the Charges and Credits– Grandfathered Net Metering and Phase One NEM, and H.3 and H.4 of the Charges and Credits – Value Stack Tariff of this Rider, as applicable, are transferred to the former CDG Host Banked Credit.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

   a. Applications by CDG Hosts - Continued

      A CDG Host Account shall not be a Remote Net Metered Host, RC Host, CDG Satellite Account, or RC Satellite Account. If the CDG Host Account was previously established under Remote Net Metering as an energy-only account whose Satellite Accounts receive monetary crediting pursuant to paragraph 2.c.(iii) of Section G of this Rider, the CDG Host must permanently surrender its rights to monetary crediting under an energy-only account before participating in CDG. If the CDG Host account was previously established as a net metered or Value Stack Tariff customer-generator or Remote Net Metered Host, it must forfeit any remaining kWhr or Value Stack credits at the time it becomes a CDG Host.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

b. Requirements of CDG Hosts

The CDG Host 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, Case 15-M-0180, and Case 15-E-0751, as they may be amended or superseded from time to time.

The CDG Host must certify to the Company in the format specified in the CDG Program Procedural Requirements, both prior to commencing net metered or Value Stack Tariff service under CDG and annually thereafter, that: (1) for all but a Farm Operation CDG Project, its CDG Satellite Accounts with demands of 25 kW or greater receive, in aggregate, no more than 40 percent of the generator's output (as adjusted, if applicable, for dwelling units of CDG Satellite Accounts billed under SC 8 or SC 12 or in multi-unit residential buildings served indirectly under the PASNY Rate Schedule); (2) for a Farm Operation CDG Project, each CDG Satellite Account is either a Farm Operation or the owner or employee of the Farm Operation; and, (3) the CDG Host meets creditworthiness standards and other requirements established by the PSC. The Company may notify the PSC if it becomes aware that a CDG project does not meet one or more of the PSC's requirements or if the CDG Host fails to provide annual certification.

A CDG Host that provides a Customer's name and account number to the Company (and such other information as the Company may require if it is unable to verify the Customer's account based on the information provided), as described in the Company's CDG Program Procedural Requirements, 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.

The Company's CDG Program Procedural Requirements and CDG Net Crediting Manual detail the format and requirements for CDG submissions. Additionally, the Company's CDG Program Procedural Requirements and UBP-DERS sets forth consumer protections required of CDG Hosts. A CDG Host may not request termination or suspension of electric service to a CDG Satellite Account.

Service under this Rider will terminate if 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 outlined in paragraph 4 of Section G and paragraph 6 of Section H of this Rider shall apply.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output

(a) CDG Projects In-Service on or before February 12, 2021

For all but Farm Operation CDG Projects, CDG Hosts that meet all the following criteria:
(1) whose in-service date is on or before February 12, 2021; and,
(2) who was a CDG Host served under the Value Stack, Grandfathered Net Metering, or Phase One NEM tariff, as applicable, on or before February 12, 2021; and,
(3) whose allocation on or prior to February 12, 2021, in accordance with the allocation submission requirements in this section c, does not meet the otherwise-applicable requirement that no more than 40 percent of the output of the CDG Host may serve CDG Satellites that have an annual average billed demand of greater than 25 kW,

must continue to use the allocation methodology accepted by the Company in its allocation, for purposes of the project's compliance with the 40 percent output limit to CDG Satellites of 25 kW or greater, for the remainder of the CDG Host's term of service.

(b) CDG Projects in Development as of February 13, 2021

For all but Farm Operation CDG Projects, CDG Hosts that meet all the following criteria:
(1) whose 25 percent of interconnection costs have been paid on or before February 12, 2021, or an SIR contract has been executed on or before February 12, 2021, if no such payment is required; and
(2) whose in-service date is on or after February 13, 2021, or whose in-service date is on or before February 12, 2021 but was not a CDG Host served under the Value Stack, Grandfathered Net Metering, or Phase One NEM tariff, as applicable, on or before February 12, 2021; and,
(3) whose initial allocation as a CDG Host serviced under the Value Stack, Grandfathered Net Metering, or Phase One NEM tariff, as applicable, in accordance with the allocation submission requirements in this section c, does not meet the otherwise-applicable requirement that no more than 40 percent of the output of the CDG Host may serve CDG Satellites that have an annual average billed demand of greater than 25 kW,

no more than 40 percent of the output of the CDG Host may serve demand-billed CDG Satellites whose percentage allocation, multiplied by the rated capacity of the CDG Host's generating equipment, exceeds 25 kW. A CDG Host that qualifies for these provisions shall have such provision apply for the remainder of the CDG Host's term of service.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output - Continued

(c) All other CDG projects, except Farm Operations CDG Projects

No more than 40 percent of the output of the CDG Host may serve CDG Satellite Accounts that have an annual average billed demand of greater than 25 kW, measured using the most recent 12 months of CDG Satellite Accounts' bills at time of the Company's receipt of a CDG Host's allocation; CDG Satellite Accounts that do not count towards the 40 percent output limit are Residential customers, Non-residential customers that are not billed on a demand basis, and Non-residential customers that are billed on a demand basis with annual averaged billed demand that is less than or equal to 25 kW, measured using the most recent 12 months of bills at time of project allocation submitted to the Company.

A CDG Host may treat each dwelling unit served indirectly under SC 8 or SC 12 or in multi-unit residential buildings served indirectly under the PASNY Rate Schedule as though it were a separate participant for determining whether the ten-CDG Satellite Account minimum and 40-percent output limit are reached.

Once a CDG Host served under the Grandfathered Net Metering, Phase One NEM, or Value Stack tariff, as applicable, begins crediting pursuant to the Grandfathered Net Metering, Phase One NEM, or Value Stack tariff, as applicable, the CDG Host must continue to use the allocation methodology approved by the Company for that project.

The Company will rely exclusively on the CDG Host's allocations pursuant to sections (i) Initial Allocation and (ii) Monthly Allocation, below, provided to the Company to verify the CDG Satellite Account's participation in the CDG Host's project.

Verification of the above requirements shall be completed by the Company each time an allocation is submitted by a CDG Host based on the methodology established during the Company's final approval of the CDG Host's initial allocation.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output - Continued

(i) Initial Allocation

At least 60 days before commencing net metered or Value Stack Tariff service under CDG, the CDG Host must submit to the Company its list of CDG Satellite Accounts and the percentage (at up to three decimal places of accuracy) of the CDG Host's net energy output to be allocated to each, as well as the percentage to be retained by the CDG Host. If less than 100.000% of the CDG Host net energy output is allocated by the CDG Host, the difference becomes the unallocated CDG Satellite percentage. Allocations that total more than 100.000% shall be rejected.

For a CDG Host served under Grandfathered Net Metering or Phase One NEM pursuant to Section G.2.a.(i), G.2.a.(ii), or G.2.b of Charges and Credits– Grandfathered Net Metering and Phase One NEM of this Rider, as applicable, the unallocated CDG Satellite percentage, together with the percentage retained by the CDG Host, will be multiplied by the CDG project's net energy output for the billing period and converted to a monetary credit, if applicable, to determine the unallocated credits.

For a CDG Host served under the Value Stack Tariff, the unallocated CDG Satellite percentage, together with the percentage retained by the CDG Host, will be multiplied by the CDG project's Value Stack compensation for the applicable billing period, excluding any Market Transition Credit and Community Credits, in accordance with paragraphs H.4.d and H.4.g. of this Rider, to determine the unallocated credits.

The unallocated credits from either the Value Stack, Grandfathered Net Metering or Phase One NEM CDG Host will be added to the CDG Host Banked Credit for future distribution to the CDG Satellites, pursuant to (iii) and (iv) below.

(ii) Monthly Allocation

For any monthly billing period in which there is insufficient metering data available to ascertain the kWhr supplied by the CDG Host to the CDG Satellite Accounts, the CDG Host's excess credits will be assumed to be zero. If actual data later becomes available, credits will be applied as appropriate.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output - Continued

(ii) Monthly Allocation - Continued

After commencing net metered or Value Stack Tariff 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. If less than 100.000% of the CDG Host net energy output is allocated by the CDG Host, the difference becomes the unallocated CDG Satellite percentage. Allocations that total more than 100.000% shall be rejected.

For a CDG Host served under Grandfathered Net Metering or Phase One NEM pursuant to Section G.2.a.(i), G.2.a.(ii), or G.2.b of Charges and Credits– Grandfathered Net Metering and Phase One NEM of this Rider, as applicable, the unallocated CDG Satellite percentage, together with the percentage retained by the CDG Host, will be multiplied by the CDG project's net energy output for the billing period and converted to a monetary credit, if applicable, to determine the unallocated credits.

For a CDG Host served under the Value Stack Tariff, the unallocated CDG Satellite percentage, together with the percentage retained by the CDG Host, will be multiplied by the CDG project's Value Stack compensation for the applicable billing period, excluding any Market Transition Credit and Community Credits, in accordance with paragraphs H.4.d and H.4.g. of this Rider, to determine the unallocated credits.

The unallocated credits from either the Value Stack, Grandfathered Net Metering or Phase One NEM CDG host will be added to the CDG Host Banked Credit for future distribution to the CDG Satellites, pursuant to (iii) and (iv) below.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output - Continued

(iii) CDG Host Banked Credit Allocation

The CDG Host may allocate to CDG Satellite Accounts any portion of its CDG Host Banked Credit if written instructions are received by the Company 15 days before the CDG Host Account is next billed. The CDG Host Banked Credit allocation must be submitted in the format specified in the CDG Program Procedural Requirements. The CDG Host may allocate credits to any of their active CDG Satellites, including to non-mass market satellites who are otherwise ineligible to receive the Market Transition Credit.

(iv) Annual CDG Host Banked Credit Allocation

For Grandfathered Net Metering or Phase One NEM service, the CDG Host must furnish to the Company, once each year, no less than 30 days before the CDG Host's 12-month anniversary of commencing CDG net-metered service, written instructions for allocating the CDG Host Banked Credit, as applicable, that remain on the CDG Host Account at the end of the annual period ("Annual Credit") to one or more of its CDG Satellite Accounts. No portion of the Annual Credit may be allocated to the CDG Host Account. No distribution will be made if instructions are not received by the required date.

For Value Stack service, the CDG Host must furnish to the Company, once each year, no less than 30 days before the CDG Host Account's 12-month anniversary of commencing CDG Value Stack service, written instructions for allocating any remaining CDG Host Banked Credit at the end of the annual period ("Annual Value Stack CDG Credit") to one or more of its CDG Satellite Accounts. No portion of the Annual Value Stack CDG Credit may be allocated to the CDG Host Account. No distribution will be made if instructions are not received by the required date.

The CDG Host may allocate credits to any of their active CDG Satellites, including to non-mass market satellites who are otherwise ineligible to receive the Market Transition Credit.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

c. Allocations of Generators' Output - Continued

(iv) Annual CDG Host Banked Credit Allocation - Continued

The CDG Host Account may retain, for up to two years, measured from the end of an annual period in which credits were added to the CDG Host Banked Credit, any undistributed credit that remains after the Annual Credit or Annual Value Stack CDG Credit is distributed to the CDG Satellite Accounts, provided that the CDG Host, in its instructions for allocating the Annual Credit or Annual Value Stack CDG Credit, allocated credits to each CDG Satellite Account equal to no less than the CDG Satellite Account's total kWhr usage in the final month of the annual period, if the CDG Host Account is billed under Grandfathered Net Metering or Phase One NEM for energy-only, or no less than the CDG Satellite Account's monthly electric charges in the final month of the annual period, if the CDG Host Account is demand-billed or served under the Value Stack Tariff. At the end of the two-year period, the CDG Host Account will forfeit credits (i.e., (1) kWhr credits if the CDG Host Account is billed under Grandfathered Net Metering or Phase One NEM for energy-only; or (2) monetary credits if the CDG Host Account is demand-billed or served under the Value Stack Tariff) equal to the smallest number of credits in its account at any point during the two-year period.

d. CDG Net Crediting Program

CDG Hosts served under the Value Stack Tariff can enroll in the CDG Net Crediting Program under this Rider in conformance with the CDG Net Crediting Manual and by executing a CDG Net Crediting Agreement with the Company, at least 60 days prior to commencing participation in the CDG Net Crediting Program, in addition to any other forms and registrations required under this Rider and the Net Crediting Manual. Applications from CDG Hosts for the CDG Net Crediting Program will be accepted by the Company commencing on April 1, 2021.

The CDG Host enrollment information includes the CDG Savings Rate for the project, which is the percentage of the Value Stack compensation applied to the project's CDG Satellite accounts, excluding an Anchor Satellite, if applicable. The CDG Savings Rate may not be less than five percent and may not exceed 100 percent less the Utility Administrative Fee, as specified in paragraph 3.d.(ii) of Section F of this Rider.

The CDG Savings Rate will be applicable to all CDG Satellites designated by the CDG Host pursuant to paragraph 3.c of Section F of this Rider, except for an Anchor Satellite, if applicable, as specified in paragraph 3.d.(iv) of Section F under this Rider.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

d. CDG Net Crediting Program - Continued

The CDG Host will provide the Company the percentage of the CDG Host's net energy output to be allocated to each CDG Satellite pursuant to paragraph F.3.c. A CDG Host's enrollment in the CDG Net Crediting Program represents the enrollment of all its CDG Satellites except for an Anchor Satellite, if applicable. The CDG Host may modify its CDG Savings Rate in accordance with the CDG Net Crediting Manual no less than 30 days prior to the CDG Host account's billing date to which the modifications apply.

CDG Hosts will be required to follow the requirements provided in the Company's CDG Net Crediting Manual, which may be modified from time to time.

As described below, the Company will facilitate crediting the CDG Satellite's bills and retaining, from the same CDG Satellites, CDG Subscription Fees (from which the Company will pay the CDG Host), resulting in Net Member Credits to the CDG Satellites.

(i) Determination of CDG Satellite's Net Member Credits

The Company will calculate and apply a Net Member Credit to the participating CDG Satellite's bill based on the CDG Host's net injections and associated Value Stack Compensation, as determined in accordance with Section H under this Rider for each applicable billing period, with modifications as follows. Net Member Credits shall be determined as the CDG Savings Rate multiplied by the Applied Credit, which is defined as the minimum of:

(1) the Total Available Credit, determined as the sum of (a) the CDG Host's Value Stack Compensation for the applicable billing period as calculated in conformance with Section H under this Rider, allocated by the CDG Host to the CDG Satellite in accordance with the CDG Satellite's Allocation Percentage; (b) any Value Stack credits that have been carried forward from CDG Satellite's preceding billing periods, pursuant to paragraph 4.h.(iii) of Section H of this Rider; and (c) any Value Stack credits allocated from a CDG Host's Banked Monetary Credit (pursuant to paragraph 3.c of section F of this Rider); and

(2) the CDG Satellite's current electric bill for the applicable billing period.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

d. CDG Net Crediting Program - Continued

(i) Determination of CDG Satellite's Net Member Credits - Continued

If the Total Available Credit exceeds the CDG Satellite's current electric bill for the applicable billing period, the amount above the CDG Satellite's current electric bill will be banked on the CDG Satellite's account for use in the CDG Satellite's subsequent billing month's Total Available Credit. All provisions relating to the CDG Host Banked Credit relating to any credits that have been carried forward from a CDG Satellite's preceding billing periods pursuant to paragraph 4.h.(iii) of Section H of this Rider shall be extended to CDG Net Crediting projects.

The CDG Host and CDG Satellite may make their own agreements for any further payments between the CDG Satellite and the CDG Host, provided the Satellite is not a Mass Market Customer.

(ii) Determination of CDG Host Payment

The Company will calculate the CDG Host Payment each month and remit it to the CDG Host as a payment in the month following distribution of the Net Member Credits to the CDG Satellites. The CDG Host and the Company will follow the terms of the CDG Net Crediting Agreement and CDG Net Crediting Manual.

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 period less the Utility Administrative Fee. The CDG Subscription Fee for each CDG Satellite will be determined by subtracting the Net Member Credit from the Applied Credit. The Utility Administrative Fee is a percentage of the sum of the CDG Subscription Fees and Net Member Credits, as determined in accordance with section (i) above, for the applicable billing period. The Utility Administrative Fee will be retained by the Company to support implementation and operation costs of the program. The Utility Administrative Fee percentage will be set forth on the Value Stack Credits Statement.

(iii) Unenrollment

CDG Hosts may unenroll from the CDG Net Crediting Program with 30 days' notice, in a manner pursuant to the CDG Net Crediting Manual. A CDG Host that has previously unenrolled from the CDG Net Crediting Program may re-enroll after at least 12 months from when they were removed.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation - Continued

3. Community Distributed Generation - Continued

d. CDG Net Crediting Program - Continued

(iv) Anchor Satellite

The CDG Host may choose to designate one large CDG Satellite to be an Anchor Satellite. The selection of an Anchor Satellite must be made pursuant to the CDG Net Crediting Manual. The Anchor Satellite will be subject to the crediting rules for CDG Satellites as outlined in Section H.4.h of this Rider.

4. Switching Between Community Distributed Generation and Remote Crediting

A customer that is a CDG Host Account or RC Host Account shall be provided a one-time irrevocable option to switch from the CDG Program (including Net Crediting) to the RC Program, or vice-versa. Such CDG Host Account or RC Host Account shall provide the Company with notice of its intent to switch programs and submit a completed switching certification form within at least 60 calendar days of the new project's first account billing date or within 45 calendar days of the existing project's last Host Account billing date. The switching certification must affirm that all of the project's Satellite Accounts have been notified of program changes and that the Host has notified NYSERDA of its intent to switch from CDG to Remote Crediting or vice versa. Within five business days, the Company will review the switching certification and new Host Account allocation forms and notify the Host Account via electronic mail of any rejected accounts and the reason for the rejection. The Host Account shall respond via electronic mail and notify the Company of the notification receipt date for the record. In the case of rejected accounts, within five calendar days of notification, the Host Account shall either resubmit a revised Host Account allocation form or confirm that the Company should move forward with the original allocation form with the rejected accounts removed, via electronic mail. Additional rules for the six-step process to switch as a Host Account from a CDG Program to an RC Program, or vice versa, are addressed in_the Commission's July 14, 2022 *Order Approving Remote Crediting Banking Rules and Addressing Switching Between Community Distributed Generation and Remote Crediting Programs,* in Case 15-E-0751.

Projects that choose to switch from one Value Stack program to another Value Stack program will keep the same rates that were locked in on the project's eligibility date, and all project elections will carry forward. Projects switching from a non-Value Stack program into a Value Stack program will lock in eligibility date-specific rates on the date that the Company is notified, in the same manner as above, of the project's intent to switch programs.

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators – Continued

F. Remote Net Metering, Remote Crediting, and Community Distributed Generation – Continued

4. Switching Between Community Distributed Generation and Remote Crediting – Continued

The term of the project will depend on the program to which the project is switching. Regardless of the term (e.g., 20 or 25 years), the term start date will be based on the project's original interconnection date.

CDG Host Accounts that are currently receiving volumetric credits who switch into the RC Program must forfeit any remaining volumetric credits prior to their enrollment in RC.

For non-Value Stack CDG projects registered in the New York Generating Asset Tracking System ("NYGATS") that switch to the RC Program and are eligible to receive compensation under the Value Stack Environmental component, the project owner has the option to retain their RECs or receive the Environmental component. If transferring the RECs to the Company, the project owner must contact the NYGATS administrator to initiate a transfer of the generator in NYGATS to the Company and must authorize the Company to register and report through NYGATS by submitting the Designation of Responsible Party form.

G. Charges and Credits – Grandfathered Net Metering and Phase OneNEM

1. Charges to a Customer Served Under this Rider

   a. The Customer will pay the rates and charges of the Customer's applicable Service Classification for net energy supplied by the Company. Phase One NEM Customer-generators specified in Section A.6 of this Rider will be billed pursuant to the provisions specified in General Rule 20 for net energy supplied by the Company. If the Customer is served under time-of-day ("TOD") rates, the charge for net energy supplied by the Company will be determined for each time period.

   For an account served under Rider M or otherwise eligible to be served under Rider M on a mandatory basis, kilowatthour charges/credits for supply will be determined for each hour in which electricity is either consumed or produced and then summed for the billing period. If the result is a net credit for the billing period, the credit will be applied towards any outstanding charges, and any remaining credit will be carried forward to the succeeding billing period.

   b. A Customer served under this Rider shall pay any customer charge or minimum charge, Billing and Payment Processing Charge, and any other rates and charges under the Customer's applicable Service Classification regardless of whether the amount of energy produced by the generating equipment is less than, equal to, or greater than the amount of energy used by the Customer. A Customer taking service under a demand-billed Service Classification shall pay kW delivery charges based on the maximum demand delivered by the Company to the Customer during the billing period, and, if this is a Full Service account, shall pay kW supply charges as described in General Rule25.1.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM

1. Charges to a Customer Served Under this Rider

   c. The following provisions are applicable to all Customers served under this Rider except for Satellite Accounts:

   The Customer will be exempt from the Minimum Monthly Charge specified in General Rule 10.10. A Customer served under both this Rider and Rider Y shall be subject to all Rider Y terms and conditions, except that Contract Demand will not be used to determine demand delivery charges. If a Customer is served under both this Rider and Rider J, the Energy Delivery Charge reductions under Rider J will be applicable only to the net energy delivered by the Company.

   d. A Retail Access Customer may enter into a net metering arrangement with an ESCO. The Customer will pay the applicable rates and charges of the Customer's Service Classification based on the net amount of energy delivered by the Company during a billing period. The Customer will receive credits for supplying net energy to the Company as set forth in paragraph 2 below.

2. Credits to a Customer Who Supplies Net Energy to the Company

   a. For Customers Billed Under Energy-only Rates:

      (i) For Customers with micro-CHP generating equipment or fuel cell electric generating equipment at their premises and non-residential Customers with farm waste generating equipment at their Non-farm Location, any kWhr of net energy provided to the Company during the billing period will be converted to a monetary credit based on the Company's Avoided Energy Cost for the month. The monetary credit will be applied towards any outstanding customer or other charges, excluding the CBC Charge, in the billing period.

      Any remaining monetary credit will be carried forward to the succeeding billing period unless the Customer is: (a) an RNM Host with fuel cell electric generating equipment at its non-residential premises or Farm Operation; (b) an RNM Host with farm waste generating equipment at its Non-farm Location; or (c) a non-residential Customer that is a CDG Host. Any remaining monetary credit on an RNM or CDG Host Account will be applied as described in paragraph G.2.c.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM - Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

a. For Customers Billed Under Energy-only Rates: - Continued

(ii) For Phase One NEM Customers described in paragraphs 2. or 3. of the Phase One NEM Applicability Section of this Rider with electric generating equipment that interconnects on or after January 1, 2022 and are billed under TOD rates:

Any kWhr of net energy provided to the Company during the billing period will be converted to the equivalent monetary value at the per-kWhr rate applicable to the Customer's Service Classification. Separate monetary credits will be determined for each TOD period and added together.

The monetary credit will be applied towards any outstanding energy, customer, demand, or other charges, excluding the CBC Charge, in the billing period. Any remaining monetary credit shall be carried forward to the succeeding billing period.

(iii) For all other Customers:

Any kWhr of net energy provided to the Company during the billing period will be applied as a kWhr credit towards any net kWhr used during the succeeding billing period. If the Customer is billed under TOD rates, the kWhr credit will be determined and applied, as appropriate, to each time period.

Any remaining kWhr credit will be carried forward to the succeeding monthly billing period unless the Customer participates in Remote Net Metering or Community Distributed Generation.

RNM and CDG Host Accounts will be credited as follows:

(a) If an RNM Host's Satellite Accounts receive monetary crediting pursuant to paragraph G.2.c.(iii), any kWhr of net energy provided to the Company by the RNM Host Account shall be converted to its equivalent monetary value at the per-kWhr rate applicable to the RNM Host Account's Service Classification and applied, along with any prior period remaining monetary credits, as a direct monetary credit to the RNM Host Account's electric bill for any outstanding energy, customer, or other charges. Any remaining monetary credit on the Host Account will be applied to the RNM Satellite(s) as described in paragraph G.2.c.(iii).

(b) For all other RNM Hosts and for all CDG Hosts, any remaining kWhr credit on the RNM or CDG Host Account will be applied to its Satellite Account(s) as described in paragraph G.2.c.(iv).

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits– Grandfathered Net Metering and Phase One NEM - Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

   b. For Customers Billed Under Demand Rates:

      (i) For Customers with fuel cell electric generating equipment at their premises and non-residential Customers with farm waste electric generating equipment at their Non-farm Location, any kWhr of net energy provided to the Company during the billing period will be converted to a monetary credit based on the Company's Avoided Energy Cost for the month. The monetary credit will be applied towards any outstanding energy, customer, demand, or other charges in the billing period. Any remaining monetary credit will be carried forward to the succeeding billing period unless the Customer participates in Remote Net Metering or Community Distributed Generation, in which case the remaining monetary credit on the RNM or CDG Host Account will be applied as described in paragraph G.2.c. below.

      (ii) For all other Customers:

      Any kWhr of net energy provided to the Company will be converted to the equivalent monetary value at the per-kWhr rate applicable to the Customer's Service Classification. If the Customer participates in Remote Net Metering or Community Distributed Generation, the per-kWhr rate will be the rate applicable to the RNM or CDG Host Account's Service Classification. Where service is taken under Special Provision G of SC 9, the "per-kWhr rate" as determined under sections G.2.b and G.3.a(ii) of this Rider will exclude the System Benefits Charge and Revenue Decoupling Mechanism Adjustment. Where both high-tension and low-tension service are supplied and billed to a Customer under a single agreement, separate kWhr credits will be determined for the high-tension service and low-tension service if the per-kWhr rates differ.

      The monetary credit will be applied towards any outstanding energy, customer, demand, or other charges, excluding the CBC Charge, in the billing period. Any remaining monetary credit shall be converted back to its kWhr value and carried forward to the succeeding billing period, unless: (a) the Customer participates in Remote Net Metering or Community Distributed Generation; (b) the Customer has farm wind or farm waste electric generating equipment and is served under Rider M or would be served under Rider M on a mandatory basis if they purchased supply from the Company; or (c) the Customer is a Phase One NEM Customer described in paragraph 3. of the Phase One NEM Applicability Section of this Rider with electric generating equipment that interconnects on or after January 1, 2022 and is billed under TOD rates. If the Customer participates in Remote Net Metering or Community Distributed Generation, any remaining monetary credit on the Host Account will be applied to its Satellite Accounts as described in paragraph G.2.c. below.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM - Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

b. For Customers Billed Under Demand Rates: - Continued

(ii) For all other Customers: - Continued

If the Customer has farm wind or farm waste electric generating equipment at its Farm Operation and is served under Rider M or would be served under Rider M on a mandatory basis if the Customer purchased supply from the Company, any remaining monetary credit will be carried forward to the succeeding billing period, as described in the Commission's November 29, 2012 Order in Case 12-E-0043, in two separate credits: one for energy supply, and one for the balance of the monetary credit. The energy supply credit will be determined by multiplying the total monetary credit by the ratio of (a) the credit for energy based on NYISO market prices for the prior month's bill and the current bill to (b) the total monetary credit for the prior month's bill and the current bill. This process will be repeated each subsequent billing period to the extent excess credits remain. If the Customer also participates in Remote Net Metering, any remaining monetary credit will be applied to the Satellite Account(s) as described in paragraph G.2.c. before being carried forward on the Host Account as described hereunder.

If the Customer is a Phase One NEM Customer described in paragraphs 3. of the Phase One NEM Applicability Section of this Rider with electric generating equipment that interconnects on or after January 1, 2022 and is billed under TOD rates, any remaining monetary credit will be carried forward to the succeeding billing period.

c. Remote Net Metering and Community Distributed Generation

If the Customer participates in Remote Net Metering or Community Distributed Generation, any remaining credit on the RNM or CDG Host Account, after application pursuant to paragraphs G.2.a. and G.2.b., will be applied to each Satellite Account, as designated by the RNM or CDG Host, in the following manner:

(i) Credits on the RNM or CDG Host Account shall be applied to its Satellite Account(s) in the order in which the Satellite Account(s) are billed. RNM and CDG credits will be applied until such time that the credit is reduced to zero or all the Satellite Account(s) have been credited. If more than one RNM Satellite Account of an RNM Host bills on the same day, the credit shall be applied to its RNM Satellite Accounts in order of kWhr usage from highest to lowest.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM - Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

c. Remote Net Metering and Community Distributed Generation - Continued

(i) Continued

If an RNM Satellite Account has more than one RNM Host, it will receive credits from the RNM Host Accounts in the order in which the Host Accounts are billed. If more than one RNM Host bills on the same day, credits will be applied from the RNM Hosts to their RNM Satellite Accounts, in the following priority order, with the highest priority listed first and lowest priority listed last:

Energy-only RNM Host Accounts whose RNM Satellite Accounts receive monetary credits up to each Satellite Account's kWh usage pursuant to paragraph G.2.c.(iii);

Other energy-only RNM Host Accounts, whose RNM Satellite Accounts receive monetary credits up to each Satellite Account's outstanding electric bill; and

Demand-billed RNM Host Accounts, whose RNM Satellite Accounts receive monetary credits up to the outstanding electric bill.

Notwithstanding the above, RNM Hosts whose Satellite Accounts receive credits at the Company's Avoided Energy Cost pursuant to paragraph G.2.a.(i) or G.2.b.(i) will be applied last. Within each of the above priorities, credits from RNM Hosts with farm waste or farm wind electric generating equipment will be applied first.

(ii) The monetary credit on the RNM or CDG Host Account will be applied towards its Satellite Account's energy, customer, demand or other charges on its electric bill, if the RNM or CDG Host Account is either: billed under demand rates and credited for net energy pursuant to paragraph G.2.b.; or billed under energy-only rates and credited for net energy pursuant to paragraph G.2.a.(i).

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators – Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM – Continued

2. Credits to a Customer Who Supplies Net Energy to the Company – Continued

c. Remote Net Metering and Community Distributed Generation - Continued

(iii) The monetary credit on the RNM Host Account will be applied towards the RNM Satellite Account's energy, customer, demand or other charges on its electric bill, if the RNM Host Account is billed under energy-only rates and credited for net energy pursuant to paragraph G.2.a.(ii), provided that both of the following two conditions exist.

(1) The RNM Host Account met one of the following requirements at a qualifying remote net-metered location as of June 1, 2015:
   (a) the RNM Host Account was billed as an energy-only RNM Host Account; or
   (b) the RNM Host Account completed interconnection for the eligible generation; or
   (c) the RNM Host Account submitted a completed preliminary interconnection application under the SIR in the Customer's name to the Company; or
   (d) the RNM Host Account completed an application for a grant under NYSERDA's Program Opportunity Notice ("PON") 2112, 2439, 2589, 2860, or 2956 or the Request for Proposals ("RFP") process conducted by New York City for development of renewable facilities at the Freshkills Landfill; or
   (e) the RNM Host Account completed an application for a grant under NYSERDA's NY-Sun MW Block Program for projects sized at more than 200 kW; or
   (f) the RNM Host Account's eligible generation was solicited by a New York state, municipal, district, or local governmental entity through an RFP or a Request for Information issued in conformance with applicable law; and

(2) The eligible generation pursuant to (1) (b), (c), (d), (e), or (f) above entered service by:
   (a) the date specified in the applicable NYSERDA PON or NY-Sun MW Block Program for projects sized at more than 200 kW, or the New York City Freshkills Landfill RFP, or another governmental entity process, as that date may be extended by the relevant governmental entity; or
   (b) by December 31, 2017 if no date is specified by a governmental entity; or
   (c) after December 31, 2017, if the RNM Host Account meets all of the following conditions: (i) provided payment for a CESIR study (as required under the SIR) prior to March 1, 2016; (ii) demonstrated, upon receipt of the CESIR study results, that the estimated construction schedule will allow it to receive final authorization to interconnect on or after July 1, 2017; (iii) made payment by January 31, 2017, of the full estimated interconnection cost or at least the first installment amount; and (iv) submitted an affidavit from the engineer of record for the project by November 30, 2017, attesting that substantially all of the generating equipment has been constructed and that the only remaining requirements to interconnect the equipment depend on the Company (e.g., remaining utility construction and/or authorization to interconnect).

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

c. Remote Net Metering and Community Distributed Generation - Continued

(iii) – Continued

Customers with RNM Host Accounts described in (1)(d), (e), or (f) above must indicate in writing the solicitation that serves as the basis for their eligibility for monetary crediting. The Company will provide written acknowledgement or rejection.

The Company will apply monetary credits from the RNM Host Account to its RNM Satellite Accounts pursuant to G.2.c.(iii) for a term of up to 25 years from the later of April 17, 2015, or the project in-service date, or such longer period as may be granted by the Commission upon a showing that the contractual arrangement for financing a particular project cannot be accomplished within a 25-year period.

Customers eligible for crediting pursuant to G.2.c.(iii) will be instead be credited under G.2.c.(iv) if requested in writing: within 60 days of the Company's written acknowledgement of a preliminary interconnection application for Host Accounts described in (1)(c) above; or with preliminary interconnection applications filed after June 1, 2015, for Host Accounts described in (1)(d), (e), or (f) above. The Company will confirm in writing a Customer's selection of this option.

(iv) Except as specified in subparagraph (iii) above, if an RNM or CDG Host Account is billed under energy-only rates and credited for net energy pursuant to paragraph G.2.a.(ii), the kWhr credit on the RNM or CDG Host Account will be applied to each Satellite Account.

The kWhr credit will be applied to each RNM or CDG Satellite Account's electric bill, up to that account's kWh usage, at its equivalent monetary value at the per-kWhr rate applicable to the Satellite Account's Service Classification ("Satellite Rate"). Where the Satellite Account is billed under time-of-day rates, a Delivery Service rate that has more than one kWhr rate block, or Rider M, or is not a Full Service Customer and would otherwise be served under Rider M on a mandatory basis, the Satellite Rate will be determined as follows: (a) if the Satellite Account is billed under time-of-day rates, the kWhr credit will based on the non-time-of-day rate applicable to the Customer's Service Classification; (b) if the Satellite Account is billed under a rate that has more than one kWhr rate block, the delivery portion of the kWhr credit will be based on the highest-value block in which usage was registered on the Satellite Account's meter; and (c) if the Satellite Account is billed under Rider M, or is not a Full Service Customer and would otherwise be served under Rider M on a mandatory basis, the supply portion of the kWhr credit will be based on the rate applicable to non-Rider M Customers served under the Customer's Service Classification.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits– Grandfathered Net Metering and Phase One NEM – Continued

2. Credits to a Customer Who Supplies Net Energy to the Company - Continued

c. Remote Net Metering and Community Distributed Generation - Continued

(v) After all RNM Satellite Accounts have been credited pursuant to subparagraph (ii) or (iii) above, any remaining monetary credit will be carried forward on the RNM Host Account to the succeeding billing period. After all RNM Satellite Accounts have been credited pursuant to subparagraph (iv) above, any remaining kWhr credit will be carried forward on the Host Account to the succeeding billing period.

After a CDG Satellite Account has been credited pursuant to subparagraph (ii) above, any remaining monetary credit will be carried forward on that CDG Satellite Account to the succeeding billing period. After a CDG Satellite Account has been credited pursuant to subparagraph (iv) above, any remaining kWhr credit will be carried forward on that CDG Satellite Account to the succeeding billing period.

(vi) If a CDG Satellite Account receives a kWhr Annual Credit from its CDG Host, as described in paragraph F.2.c., the CDG Satellite Account will be credited using the methodology described in subparagraph (iv) above. Any remaining kWhr credit will be carried forward on that CDG Satellite Account to the succeeding billing period.

3. Annual Reconciliation

a. Except as described in subparagraph b. below, an Annual Reconciliation will be performed for the following types of Grandfathered Net Metering Customers: residential Customers that have solar or wind electric generating equipment at their residence, which may also be the location of the Customer's Farm Operation; Customers that have farm wind or farm waste electric generating equipment at their Farm Operation; and non-residential Customers that have farm waste electric generating equipment at their Non-farm Location. The Annual Reconciliation will be performed following the first billing period that ends on or after the last day of each calendar year, unless the Customer made a one-time election to have the Annual Reconciliation performed in an alternate month.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM - Continued

3. Annual Reconciliation - Continued

a. – Continued

The Company will promptly issue a monetary credit to Customers subject to the Annual Reconciliation. The credit will be issued as described below:

(i) If the Customer does not participate in Remote Net Metering, the monetary credit shall be issued for the value of any kWhr credit remaining after the Annual Reconciliation. The credit will be calculated at the Company's Avoided Energy Cost for the calendar year except as specified in (iii).

If a credit greater than $100 remains after issuance of the first bill in the next annual period, the Company will issue a refund. If a credit of less than $100 remains, it will be applied against future charges, unless the Customer requests a refund.

(ii) If the Customer participates in Remote Net Metering, any monetary credit remaining on the Host Account after all Satellite Account(s) have been credited (as described in Section G.2.c.) shall be converted back to the kWhr equivalent at the per-kWhr rate applicable to the Host Account's Service Classification for the current billing period. The kWhr shall then be converted to a monetary credit based on the Company's Avoided Energy Cost for the calendar year, except as specified in (iii).

If a credit greater than $100 remains after issuance of the first bill on the Host Account in the next annual period, the Company shall issue a refund. If a credit of less than $100 remains, it shall be applied against future charges, unless the Customer requests a refund.

(iii) If the Customer has farm wind or farm waste electric generating equipment at its Farm Operation and is served under Rider M or would be served under Rider M on a mandatory basis if the Customer purchased supply from the Company, the monetary credit will be equal to the energy supply credit as determined under Section G.2.b.(ii).

b. Each year, any Annual Credit on the CDG Host Account will be distributed to one or more of its CDG Satellite Accounts pursuant to the CDG Host's instructions, as described in Section F.3.c, and carried forward on that Satellite Account to the next year. Any undistributed portion of the Annual Credit will be carried forward on the CDG Host Account for up to two years and forfeited thereafter, pursuant to Section F.3.c.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM – Continued

3. Annual Reconciliation - Continued

   c. The Company will carry forward the credit to all other Customers, as described below:

      If the Customer does not participate in Remote Net Metering, any excess net energy kWhr credits shall be carried forward to the next year on the Customer's account. If the Customer participates in Remote Net Metering, any credit remaining on the RNM Host Account after all of its Satellite Accounts have been credited (as described in section G.2.c. of this Rider) shall be carried forward to the next year on the RNM Host Account.

4. Account Closure

   The Company requires an actual reading to close a Rider R account. The Company will close an account on the earlier of: (a) the first cycle date on which a reading is taken following the requested turn off date, (b) the date of a special reading, which a Customer may request at the charge specified in General Rule 17.1, or (c) the date of request for Customers with communicating AMI meters. After a CDG Satellite is removed from a monthly allocation by its CDG Host, pursuant to section F.2.c of this Rider, or its final bill is rendered on a net-metered Customer's account, including the account of an RNM or CDG Host, any remaining kWhr credit will not be cashed out or transferred, except as provided below. Any remaining CDG Host Banked Credit will not be refunded or transferred. RNM and CDG Satellite Account(s) shall no longer receive credits after the final bill is rendered on the account of its RNM or CDG Host.

   a. CDG Satellite Account Closure

      When a CDG Satellite Account is closed and a credit remains on a CDG Satellite Account after its final bill is rendered, such credit will be returned to the CDG Host Account.

      When a CDG Satellite Account terminates its subscription with a CDG Host, any remaining banked credits on a CDG Satellite Account will be transferred to the CDG Host Banked Credit. The Company will transfer any banked credits on the CDG Satellite Account to the CDG Host Banked Credit when the CDG Satellite Account is no longer included on the CDG Host's allocation.

      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 Satellite banked credits are returned to the original CDG Host Banked Credit.

      Any remaining kWhr or monetary credits described in Sections G.2.c.(v) or G.2.c.(vi) of this Rider, as applicable, will be transferred to the CDG Host Banked Credit after the CDG Satellite's final bill is rendered.

GENERAL RULES

24. Service Classification Riders (Available on Request) –Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff

1. The Company will employ two readings: net hourly consumption from the Company's system and net hourly injections into the Company's system.

2. The Customer will be billed for the net hourly consumption in a billing period at the rates specified in the Customer's applicable Service Classification, including applicable customer, metering, and demand charges. Customer-generators specified in Sections A.6 and A.9 of this Rider will be billed for the net hourly consumption in a billing period pursuant to the provisions specified in General Rule 20.

3. For CDG Accounts, the net hourly injection kWhr generated on the CDG Host Account will be allocated to the CDG Host and CDG Satellite Accounts based on the Allocation of Generator Output methodology outlined in section F.3.c. of this Rider. Each CDG Satellite Account will then be credited for its allocated net hourly injections as described in (4) below. For RC Accounts, the net hourly injection kWhr generated on the RC Host Account will be converted to a monetary value as described in (4) below and distributed to the RC Host and RC Satellite Accounts as described in section F.2 of this Rider.

4. The Customer will be credited for net hourly injections as follows:

   a. Value Stack Energy Component

      For any hour in a monthly billing period where there is a net injection into the Company's system by a Customer-generator, the customer-generator will receive a credit for energy by multiplying the injection in that hour times the Value Stack Energy Component rate. These dollars will be summed up in the Customer's billing period.

      The Value Stack Energy Component rate will be equal to the NYISO's day-ahead Locational Based Marginal Price for the Customer-generator's applicable NYISO electric load zone, adjusted by the Factor of Adjustment for Losses as shown in General Rule 25.1.

      Customer-generators participating under the Wholesale Value Stack, as specified in General Rule 24.L, either directly or through an aggregation, will not receive the Value Stack Energy Component.

   b. Value Stack Capacity Component

      Customer-generators with intermittent generation (i.e., solar, wind, micro-hydro, and farm waste electric generating equipment) will choose between Alternative 1, 2, or 3 for their Value Stack Capacity Component credits as follows: Alternative 1 is the default methodology for intermittent generation; however, customer-generators with intermittent generation can choose Alternative 2 or 3; provided that, once chosen, the customer-generator cannot switch from Alternative 2 to Alternative 1 or switch from Alternative 3 to either Alternative 1 or 2. Customer generators will notify the Company in writing to make such election. For a CDG or RC Account, the Value Stack Capacity Component alternative chosen by the Host Account will be applicable to all credit allocations to Satellite Accounts served by the Host and to all allocations retained by the Host.

      Customer-generators with dispatchable generation (i.e., all other electric generating equipment served under this Rider) and customer-generators, including Stand-alone Electric Energy Storage, that are not PSL Sections 66-j and 66-l eligible resources (based on generator type) will be required to receive the Value Stack Capacity Component credit under Alternative 3.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff

4. - Continued

b. Value Stack Capacity Component

Customer-generators with intermittent generation (i.e., solar, wind, micro-hydro, and farm waste electric generating equipment) will choose between Alternative 1, 2, or 3 for their Value Stack Capacity Component credits as follows: Alternative 1 is the default methodology for intermittent generation; however, customer-generators with intermittent generation can choose Alternative 2 or 3; provided that, once chosen, the customer-generator cannot switch from Alternative 2 to Alternative 1 or switch from Alternative 3 to either Alternative 1 or 2. Customer generators will notify the Company in writing to make such election. For a CDG or RC Account, the Value Stack Capacity Component alternative chosen by the Host Account will be applicable to all credit allocations to Satellite Accounts served by the Host and to all allocations retained by the Host.

Customer-generators with dispatchable generation (i.e., all other electric generating equipment served under this Rider) and customer-generators, including Stand-alone Electric Energy Storage, that are not PSL Sections 66-j and 66-l eligible resources (based on generator type) will be required to receive the Value Stack Capacity Component credit under Alternative 3.

Customer-generators participating under the Wholesale Value Stack, as specified in General Rule 24.L, either directly or through an aggregation, will not receive the Value Stack Capacity Component.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

   b. Value Stack Capacity Component - Continued

      i. Value Stack Phase One Alternative 1: The Value Stack Phase One Capacity Component Rate 1 will be the SC No. 9 – Rate 1 capacity rate as shown on a volumetric ($/kWhr) basis on the Value Stack Credits Statement. The credit under Value Stack Phase One Alternative 1 will be calculated by multiplying the total net kWhr injection for the billing period by the customer-generator onto the Company's system by the Value Stack Capacity Component Rate 1.

      ii. Value Stack Phase Two Alternative 1: The Value Stack Phase Two Capacity Component Rate 1 will equal the monthly NYISO $/kW-month auction price multiplied by the proxy capacity factor as determined by the Commission, divided by the regional average monthly solar production (kWhr/kW) as determined by the Commission, to arrive at a volumetric ($/kWhr) rate.

      The capacity rates determined above are adjusted by the Factor of Adjustment for Losses as shown in General Rule 25.1 and excess requirements ICAP adjustments per the NYISO.

      The credit under Value Stack Phase Two Alternative 1 will be calculated by multiplying the total net kWhr injection for the billing period by the customer-generator onto the Company's system by the Value Stack Phase Two Capacity Component Rate 1. The $/kWhr capacity rates will be shown on the Value Stack Credits Statement.

      The proxy capacity factors and the regional average monthly solar production are shown on the Value Stack Credits Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

b. Value Stack Capacity Component - Continued

iii. Value Stack Phase One Alternative 2: The Value Stack Phase One Capacity Component Rate 2 will be the capacity rate as shown on the Value Stack Credits Statement, which is based on the total annual SC No. 9 – Rate 1 capacity costs concentrated into 460 hours occurring during the hours beginning 2 PM through the end of the hour beginning 6 PM during the months of June, July, and August. The credit under Alternative 2 will be calculated by multiplying net injections starting at the hour beginning 2 PM through the end of the hour beginning 6 PM in the months of June, July, and August by the Value Stack Phase One Capacity Component Rate 2 and summing these credits up in the billing period. The Value Stack Phase One Capacity Component Rate 2 will be $0/kWhr outside of the months and hours listed above. For Customers with energy storage paired with electric generating equipment, only the non-storage generation can qualify for Value Stack Phase One Alternative 2 compensation.

A Customer must elect Value Stack Phase One Alternative 2 by May 1 to be eligible to receive Value Stack Capacity Component Rate 2 beginning June 1 of that summer. A Customer electing Value Stack Phase One Alternative 2 after May 1 will remain on Value Stack Phase One Alternative 1 until April 30 of the following calendar year.

iv. Value Stack Phase Two Alternative 2: The Value Stack Phase Two Capacity Component Rate 2 as shown on the Value Stack Credits Statement is calculated on a volumetric ($/kWhr) basis annually based on the sum of the most recently available monthly NYISO $/kW-month auction prices for the 12 prior months as of May 31 of each year divided by the total number of available hours (i.e., 240 or 245). Available hours are the five hours beginning 2 PM through the end of the hour beginning 6 PM on non-holiday weekdays from June 24 to August 31. The Value Stack Phase Two Capacity Component Rate 2 will be $0/kWhr outside of the months and hours listed above.

The capacity rates determined above are adjusted by the Factor of Adjustment for Losses as shown in General Rule 25.1 and excess ICAP adjustments per the NYISO.

The credit under Value Stack Phase Two Alternative 2 will be calculated by multiplying the total net kWhr injection by the customer-generator onto the Company's system for each hour of the available hours in the billing period, as noted above, by the Value Stack Phase Two Capacity Component Rate 2 and summing these credits up for the billing period.

A Customer must elect Value Stack Phase Two Alternative 2 by May 1 to be eligible to receive Value Stack Phase Two Capacity Component Rate 2 beginning June 1 of that summer. A Customer electing Value Stack Phase Two Alternative 2 after May 1 will remain on Value Stack Phase Two Alternative 1 until April 30 of the following calendar year.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

b. Value Stack Capacity Component - Continued

v. Alternative 3: The Value Stack Capacity Component Rate 3 will be the capacity rate as shown on the Value Stack Credits Statement and will be determined by the NYISO ICAP monthly auction market clearing prices applicable in the current billing period and the applicable reserve requirement. The credit under Alternative 3 will be the product of: (1) the NYISO ICAP market clearing price in effect during the current billing period; (2) the applicable reserve requirement; (3) the customer-generator's net injection, during the New York Control Area ("NYCA") peak hour of the previous calendar year; and (4) the Factor of Adjustment for Losses as shown in General Rule 25.1.

If the metering was not in place to measure the customer-generator's net injection during the NYCA peak hour of the previous calendar year, then the Company will estimate such net injection during that hour.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff – Continued

4. Continued

c. Environmental Component

The Environmental Component credit will be calculated by multiplying the net hourly injections for the billing period by the Environmental Component Rate.

For Customers with generation that is eligible to receive Clean Energy Standard Tier 1 Renewable Energy Credits ("RECs"), Customers will transfer all RECs generated by the generator to the Company and receive compensation under the Environmental Component unless: (1) they make a one-time irrevocable election prior to the date of interconnection to retain all RECs generated by the generator; or (2) the customer-generator paid at least 25 percent of its interconnection costs after August 13, 2019, or executed an interconnection agreement after this date if no such payment was required, and does not meet the definition of an eligible energy system as defined in the Climate Leadership and Community Protection Act ("CLCPA") or in Public Service Law Section 66-p ("non-CLCPA eligible customers"). Customers who retain the RECs, including non-CLCPA eligible customers, will not receive compensation under the Environmental Component. The Company will be the Responsible Party within the New York Generation Attribute Tracking System ("NYGATS") for all Tier 1 eligible Value Stack projects receiving compensation under the Environmental Component, including Tranche 0 CDG projects, and will receive all associated RECs. Tier 1 eligible Value Stack projects making an election to opt-out of receiving compensation under the Environmental Component and retain their RECs must designate a Responsible Party with NYGATS. Customers with Stand-alone Electric Energy Storage will not be eligible for the Environmental Component.

To the extent that any changes are made to the types of generators included in the CLCPA definition of an eligible energy system in the future, then the new projects meeting the new requirements will be eligible for the Environmental Component and existing projects not receiving the Environmental Component will have the option to transfer their RECs to the Company and receive compensation under the Environmental Component prospectively, once such a change has been enacted.

For Customers who elect to transfer their RECs to the Company and for CDG Satellite Accounts whose CDG Host Account elects to transfer their RECs to the Company, the Environmental Component Rate will be set forth on the Value Stack Credits Statement. For all other Customers, the Environmental Component Rate is $0/kWhr.

The Environmental Component Rate will be determined at the time the Customer pays at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required or, for a Customer opting into the Value Stack Tariff that has already met either of these criteria in the interconnection process, at the time the Customer opts-in to the Value Stack Tariff and will be fixed for the term of the customer-generator's eligibility of 25 years from the project's in-service date.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

   d. Market Transition Credit ("MTC") Component

   A CDG project taking service under Value Stack Phase One will receive an MTC for Mass Market Customer CDG Satellite Accounts provided that the customer-generator is a PSL Section 66-j or 66-l eligible resource (based on customer type, generator type, and size). The MTC will be equal to the MTC SC No. 1 Component Rate applicable to the customer-generator's assigned Tranche (as determined in compliance with the PSC's March 9, 2017 Order in Cases 15-E-0751 and 15-E-0082) times the net injection during the billing month times the percentage of SC No. 1 Satellite Account allocations; plus the MTC SC No. 2 Component Rate times the net injection during the billing month times the percentage of SC No. 2 Satellite Account allocations.

   A Mass Market Customer who has opted into Value Stack Phase One will receive the MTC for SC No. 1 or SC No. 2 based on the customer's service classification.

   The MTC Rates for SC No. 1 and SC No. 2 are based on the active Tranche into which a customer-generator was assigned at the time the Customer paid at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required or, for a Customer opting into the Value Stack Tariff that has already met either of these criteria in the interconnection process, at the time the Customer opted-in to the Value Stack Tariff and is fixed for the term set forth in Section K of this Rider for the customer-generator.

   The MTC Component Rate shall be multiplied by a factor of 0.16 for any project with a high capacity-factor resource (i.e., a fuel cell) provided that, after August 13, 2019, the Customer paid at least 25 percent of its interconnection costs or executed the interconnection agreement if no such payment is required.

   The MTC Rates are set forth on the Value Stack Credits Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued
   e. Demand Reduction Value ("DRV") Component

The Customer's Value Stack Phase One DRV Component Rate or Value Stack Phase Two DRV Component Rate is determined at the time the Customer pays at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required or, for a Customer opting into the Value Stack Tariff that has already met either of these criteria in the interconnection process, at the time the Customer opts-in to the Value Stack Tariff.

The DRV Component Rate will be set forth on the Value Stack Credits Statement.

Customers can opt-out of receiving DRV compensation as a one-time, irreversible decision at any point during a project's Value Stack compensation term and participate in Rider T. The Customer will commence service under Rider T once all requirements for participation under Rider T have been met. Any Customer taking service under the Value Stack Tariff at the time of enrollment in Rider T will not be eligible to receive the Value Stack DRV Component for the remainder of the project's Value Stack compensation term.

A Customer taking service under the Value Stack Tariff and enrolled in Rider AC will not receive DRV compensation for the duration of their participation in Rider AC.

i. Value Stack Phase One DRV Component

The Value Stack Phase One DRV Component credit will be calculated by multiplying the customer-generator's average hourly net injection in the ten peak hours of the customer-generator's assigned Commercial System Relief Program ("CSRP") zone from the previous calendar year, weighted by the CSRP zone peak MW, by the Value Stack Phase One DRV Component Rate in effect. This credit will be calculated annually, divided by twelve, and credited monthly. If the customer-generator is a CDG Host Account or a non-Mass Market Customer Satellite Account of the customer-generator, the Value Stack Phase One DRV credit will be multiplied by the percentage of non-Mass Market Customer Account allocations to arrive at the DRV credit. Any account receiving an MTC will not be eligible to receive the Value Stack Phase One DRV.

If the metering was not in place to measure the customer-generator's average hourly net injection during the ten peak hours of the customer-generator's assigned CSRP zone from the previous calendar year, then the Company will estimate such average hourly net injection during those hours.

The Value Stack Phase One DRV Component Rate will be fixed for a period of 3 years from the customer-generator's in-service date. At the end of the initial three year period, the Value Stack Phase One DRV Component Rate will be reset and fixed for a subsequent three year period based on the then applicable Value Stack Phase One DRV Component Rate as shown on the Value Stack Credits Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

e. Demand Reduction Value ("DRV") Component - Continued

ii. Value Stack Phase Two DRV Component

The Value Stack Phase Two DRV Component credit will be calculated by multiplying the customer-generator's net injection during the available hours outlined below by the Customer's Value Stack Phase Two DRV Component rate. The available DRV hours will be those within the Customer's applicable CSRP Call Window that fall on weekdays from June 24 and September 15 inclusive, excluding Independence Day (July 4) and Labor Day (the first Monday in September). The Customer's applicable CSRP Call Window will be that in effect at the time the Customer pays at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required or, for a Customer opting into Value Stack Phase Two that has already met either of these criteria in the interconnection process, at the time the Customer opts-in to the Value Stack Phase Two.

The Customer's Value Stack Phase Two DRV Component rate and hours will be fixed for a period of 10 years from the customer-generator's in-service date. At the end of the initial 10-year period, the Customer will be transitioned to the then-applicable DRV rate and hours as shown on the Value Stack Credits Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

f. Locational System Relief Value ("LSRV") Component

Customer generators taking service under the Value Stack Tariff in eligible locations in the Company's service territory will receive an LSRV Component credit. Eligibility for an LSRV Component will be subject to MW caps by location, and eligibility will be determined and communicated to the Customer during the interconnection process.

The Customer's LSRV Component Rate will be determined at the time the Customer pays at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required or, for a Customer opting into the Value Stack Tariff that has already met either of these criteria in the interconnection process at the time the Customer opts-in to the Value Stack Tariff and will be fixed for a period of 10 years from the customer-generator's in-service date.

The LSRV Component Rate will be set forth on the Value Stack Credits Statement.

Customers can opt-out of receiving LSRV compensation as a one-time, irreversible decision at any point during a project's Value Stack compensation term and participate in Rider T. The Customer will commence service under Rider T once all requirements for participation under Rider T have been met. Any Customer taking service under the Value Stack Tariff at the time of enrollment in Rider T will not be eligible to receive the Value Stack LSRV Component for the remainder of the project's Value Stack compensation term.

A Customer taking service under the Value Stack Tariff and enrolled in Rider AC will not receive LSRV compensation for the duration of their participation in Rider AC.

i. Value Stack Phase One LSRV Component

The Value Stack Phase One LSRV Component credit will be calculated by multiplying the customer-generator's average hourly net injection in the ten peak hours in the customer-generator's assigned CSRP zone from the previous calendar year weighted by the CSRP zone peak MW times the Value Stack Phase One LSRV Component Rate in effect. This credit will be calculated annually, divided by twelve, and credited monthly.

If the metering was not in place to measure the customer-generator's average hourly net injection during the ten peak hours of the customer-generator's assigned CSRP zone in the previous calendar year, then the Company will estimate such average hourly net injection during those hours.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

f. Locational System Relief Value ("LSRV") Component - Continued

ii. Value Stack Phase Two LSRV Component

The Value Stack Phase Two LSRV Component credit will be calculated by dividing the Customer's Value Stack Phase Two LSRV Component Rate ($/kW-year) by 10, multiplying this value by the Customer-generator's minimum hourly net injections for each Value Stack Phase Two LSRV Event, and summing the total of these values. This amount will be calculated annually, divided by twelve, and credited monthly during the following calendar year. The Customer's Value Stack Phase Two LSRV Component Rate will be fixed for the first 10 years from the Customer-generator's in-service date.

Value Stack Phase Two LSRV Events will be from a minimum of one hour up to a maximum of four hours. The Company will provide at least 21 hours of notice before each Event. The LSRV capability period will be weekdays from June 24 through September 15 inclusive, excluding Independence Day (July 4) and Labor Day (the first Monday in September). Each LSRV zone will have a minimum of ten events per year. Should a Customer commence service under the Value Stack Phase Two Tariff after the start of a capability period, the number of events for which the customer can receive credit may be less than ten for that first capability period.

g. Value Stack Community Credit Component

i. Commencing with a CDG Host bill with a "from" date on or after August 1, 2020, a CDG project taking service under the Value Stack Phase One Tariff and assigned to Tranche 1, 2, or 3 will receive a Community Credit for non-Mass Market CDG Satellite Accounts provided that the customer-generator is a PSL Section 66-j or 66-l eligible resource (based on customer type and generator type). The Community Credit will be equal to the Community Credit Component Rate applicable to the customer-generator as set forth in the PSC's June 12, 2020 Order in Case 15-E-0751 times the net injection during the billing month times the percentage of the non-Mass-Market CDG Satellite Account allocations.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

g. Value Stack Community Credit Component

ii. A CDG project taking service under the Value Stack Phase Two Tariff will receive a Value Stack Phase Two Community Credit provided that the customer-generator is a PSL Section 66-j or 66-l eligible resource (based on customer type, generator type, and size). A Mass Market Customer opting into Value Stack Phase Two that is a PSL Section 66-j or 66-l eligible resource (based on customer type, generator type, and size) is also eligible to receive a Community Credit.

The Value Stack Phase Two Community Credit Component will be calculated and applied monthly by multiplying the eligible Customer-generator's total net injections (kWh) by the Value Stack Phase Two Community Credit Rate applicable at the time the Customer pays at least 25 percent of its interconnection costs or executes the interconnection agreement if no such payment is required; or for a Customer opting into the Value Stack Phase Two Tariff that has already met either of these criteria in the interconnection process, at the time the Customer opts-in to the Value Stack Tariff.

The Value Stack Phase Two Community Credit Rate was established by the Commission based on the assumed output of a solar array. The Community Credit will be available for a maximum allocation of 350 MW of eligible CDG projects under this Rate Schedule and under the PASNY Rate Schedule and on- site Mass Market Customer generation under this Rate Schedule.

Pursuant to the Commission's April 21, 2023 Order in Case 15-E-0751, projects that have not received the Community Credit MW allocations as of May 1, 2023 will no longer be eligible for the Community Credit. Customers with projects allocated a Community Credit between October 6, 2021, and May 1, 2023, and contained on a list provided by NYSERDA, have a one-time option to select the Community Credit or the Community Adder.

The Community Credit Component Rates shall be multiplied by a factor of 0.16 for any project with a high capacity-factor resource (i.e., a fuel cell) provided that, after August 13, 2019, the Customer paid at least 25 percent of its interconnection costs or executed the interconnection agreement if no such payment is required.

The terms of the Community Credit Component Rates will be fixed for the term set forth in Section K of this Rider for the Customer-generator.

The Community Credit Component Rates will be set forth on the Value Stack Credits Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

4. Continued

h. For Mass Market Customers and Large On-Site Customers, the sum of the applicable Value Stack Credits will be applied as a direct monetary credit to the Customer's current electric utility bill for any outstanding energy, customer, demand, or other electric charges, excluding the CBC Charge, if applicable. If the Customer's current billing period's Value Stack Credit exceeds the current electric bill, the remaining monetary credit will be carried forward to the succeeding billing period.

For CDG Satellite Accounts and RC Satellite Accounts, any remaining monetary credit will be carried forward on that CDG Satellite Account or RC Satellite Account to the succeeding billing period.

The Company will transfer any banked monetary credits associated with a CDG Satellite Account to the CDG Host Banked Credit when a Customer is no longer designated as a CDG Satellite on the CDG Host's monthly allocation form, pursuant to Section F.3.c of this Rider.

A Customer that was formerly a CDG Satellite may not be allocated credit from a CDG Host until the billing period after which all monetary credits are transferred to the CDG Host Banked Credit associated with the Customer's former CDG Host.

i. The CDG Host Banked Credit and an RC Host Account banked credit will be subject to the provisions described in sections F.3.c and F.2, respectively, of this Rider.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

5. Hybrid Facilities

a. For Customers with Hybrid Facilities, the Company will calculate the Value Stack Capacity Component credit, the Environmental Component credit, and the MTC (or Community Credit, as applicable) pursuant to the rules set forth below. All other Value Stack components, including the Value Stack Energy Component credit, DRV Component credit, and LSRV Component credit, will be calculated as specified in paragraphs H.4.a, H.4.e, and H.4.f of this Rider. Consistent with paragraphs H.4.b, H.4.c, H.4.d, and H.4.g. of this Rider, the Environmental Component credit will only be provided where the electric generating equipment is eligible to receive Tier 1 RECs, the MTC (or Community Credit, as applicable) will only be provided for eligible Customers and consistent with the MTC rate (or Community Credit rate) applicable to the customer, and the Value Stack Capacity Component credit will be calculated based on Alternative 1, Alternative 2, or Alternative 3 based on Customer election.

b. Customers operating Hybrid Facilities will have the opportunity to elect one of the four compensation methodologies described below in H.5.b.(i), H.5.b.(ii), H.5.b.(iii), or H.5.b.(iv). Customers will make this election at the same time they select a capacity compensation methodology in accordance with paragraph H.4.b of this Rider. The default option, if no other election is made by the Customer, is compensation methodology H.5.b.(iv) below.

Customers operating Hybrid Facilities will have a one-time option to change their initial election of H.5.b.(i) or H.5.b.(ii) to the election of H.5.b.(iii). This one-time election may be made at any time following the initial election but will 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 Electric Energy Storage system charges exclusively from the qualified electric generating equipment, the Value Stack Capacity Alternative 1 or Alternative 2 Component credit (if elected), Environmental Component credit, and MTC (or Community Credit, as applicable) will 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 paragraphs H.4.b.(i), H.4.b.(ii), H.4.b.(iii), H.4.b.(iv), H.4.c, H.4.d and H.4.g. The Value Stack Capacity Component Alternative 3 credit (if elected) will be calculated as specified in paragraph H.4.b.(v) of this Rider. Customers will be responsible for any work required to accommodate the appropriate controls and/or multiple meter configuration. The Company may require two Company time-synchronized revenue-grade meters if the Electric Energy Storage system and electric generating equipment share a common inverter, or three Company time-synchronized revenue-grade meters if the Electric Energy Storage system and electric generating equipment each have a separate inverter.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R – Net Metering and Value Stack Tariff for Customer-Generators – Continued

H. Charges and Credits – Value Stack Tariff – Continued

5. Hybrid Facilities – Continued

b. - Continued

(ii) Storage Controls Configuration – For Customers operating Hybrid Facilities who install appropriate controls to ensure that net hourly injections are only made with the Electric Energy Storage system not in a charging or discharging mode from the electric grid, the Value Stack Capacity Component Alternative 1 or Alternative 2 credit (if elected), Environmental Component credit, and MTC (or Community Credit, as applicable) will be based on net hourly injections to the Company's system and calculated as described in paragraphs H.4.b.(i), H.4.b.(ii), H.4.b.(iii), H.4.b.(iv), H.4.c, H.4.d, and H.4.g of this Rider. The Value Stack Capacity Component Alternative 3 credit (if elected) will be calculated as specified in paragraph H.4.b.(v) of this Rider. Customers will 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 5.b.(i) or 5.b.(ii) above, the Value Stack Capacity Component Alternative 1 credit (if elected), Environmental Component credit, and MTC (or Community Credit, as applicable) will 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. The Value Stack Capacity Component Alternative 2 credit (if elected) will 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. The Value Stack Capacity Component Alternative 3 credit (if elected) will be calculated as specified in paragraph H.4.b.(v) of this Rider.

(iv) Storage Default Configuration - For all other Customers with an Electric Energy Storage system paired with electric generating equipment, the Value Stack Capacity Component Alternative 1 or Alternative 2 credit (if elected), Environmental Component credit, and MTC (or Community Credit, as applicable) will be based on netting of all metered consumption and injections at the PCC over the applicable billing period. The Value Stack Capacity Component Alternative 3 credit (if elected) will be calculated as specified in paragraph H.4.b.(v) of this Rider.

(v) The Customer is responsible for any costs associated with additional metering requirements and telemetry as described in the Metering Section of this Rider.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

6. SC 11 Customer-generators taking service under this Rider as specified in Section A.9 will receive compensation fort net hourly injections based on the Value Stack Tariff rather than on the SC 11 Payment Rate for Energy and will receive compensation for capacity based on the Value Stack Tariff rather than on the SC 11 Payment Rate for Capacity. Customer-generators specified in Section A.9 and served under the Value Stack Tariff will be considered to be Rider R Customers for the purposes of this Rate Schedule. Customer-generators qualifying for Section A.9 and not taking service under the Value Stack Tariff will not be considered to be Rider R Customers for the purposes of this Rate Schedule.

7. A Full Service Customer-generator with a Hybrid Facility or Stand-alone Electric Energy Storage technology served under the Value Stack Tariff is subject to the provisions of Rider M.

8. Crediting under the Value Stack Tariff will commence with the bill to the customer-generator having a "from" date that commences after all necessary metering is installed and final acceptance as per the SIR has been granted by the Company.

9. After a final bill is rendered for a Customer receiving Value Stack credits, any remaining credit will not be cashed out, refunded, or transferred.

   When a CDG Satellite Account is closed, any remaining monetary credit described in Sections H.3 and H.4 of this Rider, as applicable, will be transferred to the CDG Host Banked Credit after the CDG Satellite's final bill is rendered.

   Any remaining banked monetary credits removed from a CDG Satellite's bank and added to a CDG Host Banked Credit will be returned in full without any reduction for the Market Transition Credit or Community Credit, if applicable. CDG Hosts are permitted to allocate returned credits to any of their active CDG Satellites in accordance with Section F.2.c of this Rider; returned credits may also be allocated to non-mass market satellites who are otherwise ineligible to receive Market Transition Credit or Community Credit compensation.

10. Value Stack Credits Statements will be filed with the Commission no less than three days prior to the effective date. The Value Stack Credits Statement will be posted to the Company's website prior to its effective date.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

H. Charges and Credits – Value Stack Tariff - Continued

11. Effective September 1, 2023, Customers that are allocated Value Stack credits where the credits are applied more than two calendar months after the Value Stack generator's applicable bill period ends will be credited $10.00 for each month beyond the two months that the Value Stack credits are delayed ("Monthly Credits"). The Monthly Credits will be provided for any delayed Value Stack credits retroactive to June 1, 2023. The Monthly Credits will be placed on Customer accounts during the same period the Value Stack credits are provided.

    Monthly Credits will not be provided in instances where the delay in crediting is caused by the CDG or Remote Crediting Host not timely providing the Company with an up-to-date subscriber list and/or allocations.

    Unless otherwise ordered by the Commission, the provision of Monthly Credits will end if the Commission adopts a statewide negative revenue adjustment and/or customer compensation requirement for CDG and/or VDER billing and crediting performance.

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

I. Charges and Credits – Customer Benefit Contribution ("CBC") Charge

Phase One NEM Customers described in paragraph 3. of the Phase One NEM Applicability Section of this Rider with electric generating equipment that interconnects on or after January 1, 2022, who either remain on Phase One NEM or receive compensation under the Value Stack Tariff will be subject to a CBC Charge for the Customer's term of service specified in Section K. The amount a customer is billed for the CBC will be determined each billing period by multiplying the CBC Charge by the nameplate capacity rating in kW DC of the customer's electric generating equipment.

For Customers with more than one electric generating technology for which the CBC is applicable, the CBC Charge will be assessed separately based on the nameplate capacity rating of each technology; however, where one of the multiple electric generating technologies is an Electric Energy Storage system, the CBC shall be assessed solely on the nameplate rating(s) of the other electric generating technology or technologies.

The CBC Charge cannot be offset by any credit described in Sections G and H of this Rider.

The CBC rates will be set forth on the Statement of Customer Benefit Contribution. This Statement will be filed with the Commission at least 15 days before January 1 of each year.

J. Restrictions

Service under this Rider shall not be available to a Customer taking service under:

(a) SC 9 – Special Provision H; or
(b) the PASNY Rate Schedule, except PASNY CDG Satellites of CDG Hosts taking service under this Rate Schedule.

With the exception of the Customer-generators specified in Section A.6 and Section A.9 of this Rider and Rate Choice Customers as described in General Rule 20, all other Customers served under this Rider shall be exempt from General Rule 20.

Customers served under Section A.9 of this Rider are ineligible to take service under Option C of Rider Q.

Customers served under Grandfathered Net Metering and Phase One NEM of this Rider are ineligible to participate in Rider AC.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

K. Term of Service

Unless otherwise directed by the Public Service Commission, there is no end-date to the term of service under this Rider for Customers with Grandfathered Net Metering, except for RNM Customers receiving monetary crediting under Section G.2.c.(iii). The term of service for those Customers is 25 years from the later of April 17, 2015, or the project in-service date.

The term of service under this Rider is 20 years from the in-service date for Customers with Phase One NEM, unless a one-time, irrevocable election was made to opt-in to the Value Stack Tariff or the Commission issues a new compensation methodology.

The term of service under this Rider is 25 years from the project's in-service date for Customers served under the Value Stack Tariff. Generators currently in-service for greater than 25 years at the time of application under this Rider can take service under the Value Stack Tariff until such time that a successor to the Value Stack Tariff is established by the Commission.

At the end of the term of service, Customers with on-site generation, RNM Host Accounts, RC Host Accounts, CDG Host Accounts, RNM Satellite Accounts, RC Satellite Accounts, and CDG Satellite Accounts will forfeit any net-metering or Value Stack credit that remains. Projects still in operation will be billed and credited based on the tariff that is then in effect.

A Customer served under A.9 of this Rider may elect to change its compensation mechanism (i.e., the Value Stack Tariff credit or the SC 11 Payment Rate for Energy and Payment Rate for Capacity, as applicable) no more than once every 12 months, with 60 days' notice.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

L. Wholesale Value Stack

Value Stack Customers, including Customers served under Section A.9 of this Rider, exporting to the NYISO or to third parties, either directly or through an aggregation, can take service under the Wholesale Value Stack ("WVS") as follows:

1. WVS Customers will receive payment for the energy and capacity (if applicable) components directly from the NYISO in lieu of the Company's Value Stack Tariff under Sections H.4.a. and H.4.b of this Rider.

2. WVS Customers are still eligible to receive the applicable compensation under Value Stack Tariff Sections H.4.c. – H.4.g: Environmental Component Credit, Market Transition Credit ("MTC") Component, Demand Reduction Value ("DRV") Component, Locational System Relief Value ("LSRV") Component, and the Value Stack Community Credit Component.

3. An existing Value Stack Tariff Customer electing to take service under WVS must make that election by August 1 for such service to be effective the following May 1. Similarly, an existing WVS Customer who then elects to export directly to the Company under the Value Stack Tariff must notify the Company by August 1 for such service to be effective the following May 1.

   a. If the Customer-generator was previously enrolled in the Value Stack, the Customer-generator must return to its Value Stack Capacity Component compensation election. In addition, such Customer-generator will retain the same Value Stack Eligibility Date as well as any Value Stack component rates elected at the time of previous Value Stack eligibility.

   b. If the Customer-generator was not previously enrolled in the Value Stack, the Customer-generator must elect any Eligibility Date-specific component rates at the time the project notifies the Company of the project's intent to switch from WVS to Value Stack.

   c. All Customer-generators opting into the Value Stack from the WVS will have a term based on the Value Stack compensation methodology and the start date of such term will be based on the project's original interconnection to the Company's distribution system.

4. Customers who are not yet interconnected to the Company's distribution system that are eligible for Value Stack and that elect to participate in WVS must notify the Company at time of the Customer's Value Stack Eligibility Date to receive compensation under the WVS at time of successful enrollment with the NYISO.

5. A WVS Customer must also take service under WDS and execute the applicable Service Agreement for Wholesale Distribution Service.

6. WVS Customers must meet all of the eligibility and metering requirements that a Value Stack Customer must meet.

Customers exporting to the NYISO or to third parties, either directly or through an aggregation, are ineligible to participate in Grandfathered Net Metering or Phase One Net Metering.

Exhibit 6

New York State
Public Service Commission

New York State Standardized Interconnection Requirements and Application Process For New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems

Effective: February 1, 2024

Table of Contents

Section I. Application Process

A. Introduction

This Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (SIR) provides a framework for processing applications to:

- interconnect new distributed generation (DG) facilities with an alternating current (AC) generator nameplate rating of 5 MW or less aggregated on the customer side of the point of common coupling (PCC);
- interconnect new energy storage system (ESS) facilities with an AC inverter/converter nameplate rating of 5 MW or less aggregated on the customer side of the PCC that may be stand-alone systems or combined with existing or new DG (Hybrid Projects), however, maximum export capacity onto the utility distribution system is capped at an AC nameplate rating or AC inverter/converter nameplate rating of 5 MW; and,
- review any modifications affecting the interface at the PCC to existing DG and/or ESS facilities with an AC nameplate rating of 5 MW or less (aggregated on the customer side of the PCC) that have been interconnected to the utility distribution system, and where an existing contract between the applicant and the utility is in place.

Distributed Generation or Energy Storage Systems neither designed to operate, nor operating, in parallel with the utility's electrical system are not subject to these requirements. This document will ensure that applicants are aware of the technical interconnection requirements and utility interconnection policies and practices. This SIR will also provide applicants with an understanding of the process and information required to allow utilities to review and accept the applicants' equipment for interconnection in a reasonable and expeditious manner.

The time required to complete the process will reflect the complexity of the proposed project. Projects using previously submitted designs certified per the requirements of Section II.H, Equipment Certification, will move through the process more quickly, and several steps may be satisfied with an initial application depending on the detail and completeness of the application and supporting documentation submitted by the applicant. Applicants submitting systems utilizing certified equipment however, are not exempt from providing utilities with complete design packages necessary for the utilities to verify the electrical characteristics of the generator systems, the interconnecting facilities, and the impacts of the applicants' equipment on the utilities' systems.

The application process and the attendant services must be offered on a non-discriminatory basis. The utilities must clearly identify their costs related to the applicants' interconnections, specifically those costs the utilities would not have incurred but for the applicants' interconnections. The utilities will keep a log of all applications, milestones met, and justifications for application-specific requirements. The applicants are to be responsible for payment of the utilities' costs, as provided for herein. Any unspent project analysis/study fees shall be applied forward to any subsequent analysis applicable to a given application/project.

All application timelines shall commence the next Business Day following receipt of information from the applicant or the utility. For purposes of determining the date of an applicant's payment, when a payment is required, fees paid by wire transfer shall be deemed paid on the day of the transfer, whereas fees paid by check shall be deemed paid on the day the check clears.

Staff of the Department of Public Service ("DPS Staff") will monitor the application process to ensure that applications are addressed in a timely manner. To perform this monitoring function, DPS Staff will meet periodically with utility and applicant representatives.

A glossary of terms used herein is provided in Section III.

B. Application Process Steps for Systems 50 kW or Less

Exception 1:

For inverter based systems above 50 kW up to 300 kW, applicants may follow the expedited application process outlined in this section provided that the inverter based system has been certified and tested in accordance with the most recent revision of UL 1741, including supplement B ("UL 1741 SB") , with settings as specified in the utility's technical requirements document , and the utility has approved the project accordingly. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for the expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the inverter based system is not eligible for the expedited application process, the applicant can:

1) Proceed with the remaining steps of Section I.C of the SIR (Systems above 50 kW up to 5 MW); or
2) request a review by DPS Staff.

Exception 2:

For non-inverter based system 50 kW or less, the applicant should be aware that additional information and review time may be required by the utility (refer to Step 3). The applicant must include the items required in Step 5 of the Application Process Steps for Systems above 50 kW up to 5 MW in its original application. This exception should not be considered the rule but used by the utility only in justified situations. Utilities are encouraged to use the expedited process whenever possible. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the non-inverter based system is not eligible for the expedited application process, the applicant can:

1) Proceed with the remaining steps of Section I.C of the SIR (Systems above 50 kW up to 5 MW); or
2) Request a review by DPS Staff.

Exception 3:

For all systems 50 kW or less, that are proposed to be installed in underground secondary network areas, the applicant should be aware that additional information and review time may be required by the utility (refer to Step 3). In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities. For this reason, additional review and analysis may be needed on a case by case basis. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for the expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the DG system cannot be interconnected, the applicant can request a review by DPS Staff.

STEP 1: Initial Communication from the Potential Applicant

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project

Technical staff from the utility may discuss the scope of the interconnection with the potential applicant (either by phone or in person) and provide a copy of the SIR document and any utility specific technical specifications that may apply. A utility representative shall be designated to serve as the single point of contact for the applicant in coordinating the potential applicant's project with the utility.

STEP 3: Potential Applicant Files an Application

The potential applicant submits an application package in the name of the customer[1] to the utility. No application fee is required of the applicant for systems 50 kW or less. A complete application package will consist of all items detailed in Appendix F. Electronic submission of all documents via the Interconnection Online Application Portal ("IOAP") is required. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, meets the SIR technical requirements in Section II, and/or approved for interconnection if all other requirements are met. The utility shall notify the applicant by email, fax, or other form of written communication. If the application is deemed not complete by the utility, the utility shall provide a detailed explanation of the deficiencies identified and a list of the additional information required from the applicant.

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1 Per the Community Distributed Generation Program Order (issued July 17, 2015, in Case 15-E-0082), the project sponsor shall submit the interconnection application to the electric utility for approval. The sponsor may be any single entity, including the generation facility developer, an energy service company (ESCO), a municipal entity such as a town or village, a business or not-for-profit corporation, a limited liability company, a partnership, or other form of business or civic association.

Once it has received the required information, the utility shall notify the applicant of the acceptance or rejection of the application within ten (10) Business days. If the applicant fails to submit the additional information to the utility within thirty (30) Business Days following the date of the utility's written notification, the application shall be removed from the queue and no further action on the part of the utility is required.

The utility's notification of acceptance to the applicant shall include an executed New York State Standardized Interconnection Contract and the applicant may proceed with the proposed installation. The utility shall also indicate in its response to the applicant whether or not it plans to witness the testing and verification process in person.

An application will be placed in each utility's interconnection inventory once it is accepted as complete. If the final acceptance as set out in Step 6 below is not completed within twelve (12) months as a result of applicant inactivity, the utility has the right to notify the applicant by U.S. first class mail with delivery receipt confirmation or via email that the applicant's project will be removed from the utility's interconnection inventory if the applicant does not respond within thirty (30) Business Days of the issue of such notification and provide a project status update and/or justification as to why the project should remain in the utility's interconnection inventory for an additional period of time.

With respect to an applicant proposing to install a system rated 25 kW or less, that is to be net- metered, if the utility determines that it is necessary to install a dedicated transformer(s) or other equipment to protect the safety and adequacy of electric service provided to other customers, the applicant shall be informed of its responsibility for the actual costs for installing the dedicated transformer(s) and other safety equipment. Appendix E sets forth the responsibility each applicant shall have with respect to the actual cost of the dedicated transformer(s) and other safety equipment.

STEP 4: System Installation

The applicant will install the DG system according to the utility accepted design and the equipment manufacturer's requirements. If there are substantive design variations from the originally accepted system diagram, a revised system diagram (and other drawings for non-inverter based systems) shall be submitted by the applicant for the utility's review and acceptance. All inverter based systems will be allowed to interconnect to the utility system for a period not to exceed two hours, for the sole purpose of ensuring proper operation of the installed equipment.

For net metered systems as defined in Section II.A.6, Metering, any modifications related to metering configurations to allow for net energy metering for residential, farm service and non-residential wind electric generating systems shall be completed by the utility within ten (10) Business Days of either notification to the utility that the installation has been completed and inspected, or a request for a verification test, whichever comes first. If the utility requires inspection of the new metering configuration installation, such inspection shall be completed within the ten (10) Business Days allotted for the new meter installation.

STEP 5: The Applicant's Facility is Tested in Accordance with the Standardized Interconnection Requirements

Verification testing will be performed by the applicant in accordance with the written verification test procedure specified in Appendix F. If the utility requested to witness the testing and verification process in person as required in Step 3, the applicant shall provide a written letter of notification to the utility that the system installation is completed, including any applicable inspections and authorization. After receipt of notification, the verification testing will be performed within ten (10) Business Days, at a mutually agreeable time. If the utility has opted not to witness the test, the applicant will send the utility within five (5) Business Days of completion of such tests a written notification certifying that the system has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 5. The applicant must have complied with, and must continue to comply with, all contractual and technical requirements.

STEP 6: Final Acceptance

Within five (5) Business Days of receiving the written notification of successful test completion from Step 5, the utility will issue to the applicant a formal letter of acceptance for interconnection. Within five (5) Business Days of the completion of the on-site verification, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the system.

C. Application Process Steps for Systems above 50 kW up to 5 MW

If, at any point in its review of an application, the utility determines that the project may benefit from or require a Qualifying Upgrade, the procedures of Appendix E shall apply.

For inverter based systems above 50 kW up to 300 kW, certified and tested in accordance with the most recent revision of UL 1741, including supplement B (UL 1741 SB), and with settings as specified in the utility's technical requirements document , applicants and utilities are encouraged, but not required, to use the expedited application process (Section I.B).

Exception 1: For all systems 50 kW up to 5 MW that are proposed to be installed in underground secondary network areas, the applicant should be aware that a Coordinated Electric System Interconnection Review (CESIR) may be required by the utility, based on each utility's specific technical requirements and design considerations on a case-by-case basis. In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities. The utility has ten (10) Business Days upon receipt of the original application submittal and payment to determine if the application is complete and whether it is eligible for interconnection. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the DG system cannot be interconnected or requires additional information be submitted and/or additional review time is needed, the applicant can:

1) Work with the utility on an appropriate timeframe and approval schedule agreeable to both parties; or

2) request a review by DPS Staff.

STEP 1: Initial Communication from the Potential Applicant.

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project.

Technical staff from the utility may discuss the scope of the interconnection with the potential applicant (either by phone or in person) and shall provide a copy of the SIR and any utility specific technical specifications that may apply. A utility representative shall be designated to serve as the single point of contact for the applicant in coordinating the potential applicant's project with the utility. At this time the applicant may also request that a Pre-Application Report (see Appendix D herein) be provided by the utility. The applicant shall provide a non-refundable fee of $750 with its request for completion of the Pre-Application Report. The Pre-Application Report shall be provided to the applicant within ten (10) Business Days of receipt of the form and payment of the fee. The Pre-Application Report will be non-binding and shall only provide the electrical system data and information requested that is readily available to the utility. Should the applicant formally apply to interconnect their proposed DG project within fifteen (15) Business Days of receipt of the utility's Pre-Application Report, the $750 will be applied towards the application fee in Step 3.

STEP 3: Potential Applicant Files an Application

The potential applicant submits an application to the utility in the name of the customer.[2] A complete application package will consist of all items detailed in Appendix F. Electronic submission of all documents via the Interconnection Online Application Portal (IOAP) is required. If a Pre-Application Report has been provided to the customer, and an application is received by the utility within fifteen (15) Business Days of the date of issue of the Pre-Application Report, a $750 credit will be applied towards the application fee. If an application is received by the utility later than fifteen (15) Business Days from the date of issue of the Pre-Application Report, the $750 fee will not be applied to the application fee. If the applicant proceeds with the project to completion, the application fee will be applied as a payment to the utility's total cost for interconnection, including the cost of processing the application.

The utility shall review the application to determine whether it is complete in accordance with Appendix F, and whether any additional information is required from the applicant. The utility shall notify the applicant in writing within ten (10) Business Days following receipt of the application and the application fee. If the application is not complete, the utility shall provide a detailed explanation of the deficiencies and provide a list of additional

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2 Per the Community Distributed Generation Program Order (issued on July 17, 2015, in Case 15-E-0082), the project sponsor shall submit the interconnection application to the electric utility for approval. The sponsor may be any single entity, including the generation facility developer, an energy service company (ESCO), a municipal entity such as a town or village, a business or not-for-profit corporation, a limited liability company, a partnership, or other form of business or civic association.

information needed to the applicant. The utility shall notify the applicant by email, fax, or other form of written communication. The utility review at this stage is limited to the determination of completeness from an administrative perspective and does not mean the application has also received approval from an engineering perspective. The utility may require supplemental materials and information for purposes of performing a CESIR.

If the applicant fails to submit all items required by Appendix F, or to provide additional information identified by the utility within thirty (30) Business Days following the date of the utility's notification, the application shall be deemed withdrawn and no further action on the part of the utility is required.

A completed application shall be placed in the utility's interconnection queue.

If the required documentation is presented in this step, it will allow the utility to move to Step 4 and perform the required reviews and allow the process to proceed as expeditiously as possible.

The utility will refund any advance payments for services or construction not yet completed should the applicant be removed from the utility's interconnection inventory. If the costs incurred by the utility exceed the advance payments made by the applicant prior to removal from the interconnection inventory, the applicant will receive a bill for any balance due to the utility.

STEP 4: Utility Performs Preliminary / Supplemental Screening Analysis and Develops a Cost Estimate for the Coordinated Electric System Interconnection Review (CESIR) if required

The utility shall perform a Preliminary Screening Analysis of the proposed system interconnection utilizing the technical screens A through F detailed in Appendix G. The Preliminary Screening Analysis shall be completed and a written response detailing the results of each screen and the overall outcome of the Preliminary Screening Analysis shall be sent to the applicant within fifteen (15) Business Days of the completion of Step 3. Depending on the results of the Preliminary Screening Analysis and the subsequent choices of the applicant, the following process(es) will apply:

If the Preliminary Screening Analysis finds that the applicant's proposed system passes all of the relevant technical screens (i.e., Screens A through F) and is in compliance with the Interconnection Requirements outlined in Section II, and there are no requirements for Interconnection Facilities or Distribution Upgrades, the utility will return a signed and executed New York State Standardized Interconnection Contract to the applicant. The applicant will sign and return the contract within 15 Business Days after receipt from the utility and proceed with the interconnection process.

If the Preliminary Screening Analysis finds that the applicant's proposed system cannot pass all of the relevant technical screens (i.e., Screens A through F), the utility shall provide the technical reasons, data and analysis supporting the Preliminary Screening Analysis results in writing. The applicant shall notify the utility within ten (10) Business Days following such notification whether to (i) proceed to a Preliminary Screening Analysis results meeting, (ii) proceed to Supplemental Screening Review, (iii) proceed to a full CESIR, or (iv) withdraw the Interconnection Request. If a cost estimate for the CESIR is not provided with the Preliminary

Screening Analysis results, the utility shall provide one within five (5) Business Days of a request from the applicant. If the applicant opts to proceed to a full CESIR, the utility shall provide an invoice for the CESIR fee to the applicant within ten (10) Business Days of receipt of the applicant's notification. The applicant shall have ten (10) Business Days from receipt of the invoice to pay the CESIR fee. If the applicant fails to meet either the notification or the payment deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

i. If the applicant chooses to proceed to a Preliminary Screening Analysis results meeting and modifications that obviate the need for Supplemental Screening Analysis are identified, and the applicant and the utility agree to such modifications, the utility shall return a signed and executed New York State Standardized Interconnection Contract within fifteen (15) Business Days of the Preliminary Screening Analysis results meeting if no Interconnection Facilities or Distribution Upgrades are required. The applicant will sign and return the contract within 15 Business Days after receipt from the utility and proceed with the interconnection process.

   If Interconnection Facilities or Distribution Upgrades are required and agreed to, the utility shall provide the applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Preliminary Screening Analysis results meeting. The applicant will pay the cost estimate as provided in Section I-D.

   If the applicant chooses to proceed to a Preliminary Screening Analysis results meeting and modifications that obviate the need for Supplemental Analysis are not identified and agreed to, the applicant shall notify the utility within ten (10) Business Days of the meeting of their intention to (i) proceed to Supplemental Screening Analysis, (ii) proceed to a full CESIR, or (iii) withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

ii. Applicants that elect to proceed to Supplemental Screening Analysis shall provide a nonrefundable fee of $2,500 with their response; however actual costs up to a maximum of $5,000 will be billable to the applicant upon reconciliation of utility costs as defined in Step 11 or exit from the interconnection queue. The utility shall complete the Supplemental Screening Analysis within twenty (20) Business Days, absent extraordinary circumstances, following authorization and receipt of the fee. If the Supplemental Screening Analysis finds that the applicant's proposed system passes all of the relevant technical screens (i.e., screens G through I) and is in compliance with the Interconnection Requirements outlined in Section II, then there are no requirements for Interconnection Facilities or Distribution Upgrades. Thus, the utility will return a signed and executed New York State Standardized Interconnection Contract to the applicant within fifteen (15) Business Days of providing the applicant the results of the Supplemental Screening Analysis. The applicant will sign and return the contract within fifteen (15) Business Days after receipt from the utility and proceed with the interconnection process.

If the Supplemental Screening Analysis finds that the applicant's proposed system cannot pass all of the relevant technical screens (i.e., Screens G through I), the utility shall provide the technical reasons, data, and analysis supporting the Supplemental Screening Analysis results in writing. The applicant shall notify the utility within ten (10) Business Days following such notification whether to (i) proceed to a Supplemental Screening Analysis results meeting, (ii) proceed to a full CESIR, or (iii) withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

i. If the applicant chooses to proceed to a Supplemental Screening Analysis results meeting and modifications that obviate the need for a CESIR are identified, and the applicant and the utility agree to such modifications, the utility shall return a signed and executed New York State Standardized Interconnection Contract within fifteen (15) Business Days of the Supplemental Screening Analysis results meeting if no Interconnection Facilities or Distribution Upgrades are required. The applicant will sign and return the contract within fifteen (15) Business Days after receipt from the utility and proceed with the interconnection process.

   If Interconnection Facilities or Distribution Upgrades are required and agreed to, the utility shall provide the applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Supplemental Screening Analysis results meeting. The applicant will pay the cost estimate as provided in Section D.

ii. If the applicant chooses to proceed to a Supplemental Screening Analysis results meeting and modifications that obviate the need for a CESIR are not identified and agreed to, the applicant shall notify the utility, within ten (10) Business Days of the meeting, of their intention to proceed to a full CESIR or withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

iii. If the applicant decides to proceed to a CESIR after the Supplemental Screening Analysis results meeting, or if the applicant chooses at any time in the above process to proceed directly to a CESIR, the utility shall provide a cost estimate for the CESIR, if not already provided with preliminary analysis results, within five (5) Business Days of a request from the applicant. If the applicant opts to proceed to a full CESIR, the utility shall provide an invoice for the CESIR fee to the applicant within ten (10) Business Days of receipt of the applicant's notification. The applicant shall have ten (10) Business Days from receipt of the invoice to pay the fee. If the applicant fails to meet the payment deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

If Interconnection Facilities or Distribution Upgrades are required to interconnect a proposed system that passes the relevant screens, the utility shall provide the applicant with a non-binding cost estimate for the Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Preliminary or Supplemental Screening Analysis. The applicant will pay the cost estimate as provided in Section D.

STEP 5: Applicant Commits to the Completion of the CESIR

Prior to commencement of the CESIR, the applicant shall provide the following information to the utility:

- a complete updated interconnection design package, if there have been any changes to the documents submitted with the application;
- proof of site control by executing the New York State Standard Site Control Certification Form, Appendix J;
- the name, phone number, and agent letter of authorization (if appropriate) of the individual(s) responsible for addressing technical and contractual questions regarding the proposed system;
- if applicable, advance payment of the costs associated with the completion of the CESIR; and
- electrical studies as requested by the utility to demonstrate that the design is within acceptable limits, inclusive and not limited to the following: system fault, relay coordination, flicker, voltage drop, and harmonics. This shall include all relay, communication, and controller set points.

The utility may require a three-line diagram for solar photovoltaic (PV) and BESS designs proposed on three-phase systems, which shall include detailed information on the wiring configuration at the PCC and an exact representation of the existing utility service.

If the utility determines that the detailed interconnection design package provided by the applicant is incomplete or otherwise deficient, the utility shall notify the applicant within ten (10) Business Days and provide a detailed explanation of the deficiencies identified and a list of what is required by the applicant. Unless otherwise notified by the utility, the CESIR review period begins upon confirmed receipt and acceptance of the applicant's interconnection design package and associated fees.

If the applicant fails to provide the utility authorization to proceed, CESIR fee, and information requested within thirty (30) Business Days of the request, the application shall be removed from the queue and no further action on the part of the utility is required.

STEP 6: Utility Completes the CESIR

The CESIR will consist of two parts:

1) a detailed review and explanation of the impacts to the utility system associated with the interconnection of the proposed system, and
2) a detailed review and explanation of the proposed system's compliance with the

applicable criteria set forth below.

A CESIR will be performed by the utility to determine if the proposed generation on the circuit results in any protective coordination, fault current, thermal, voltage, power quality, or equipment stress concerns.

The CESIR shall be completed within sixty (60) Business Days of receipt of the information set forth in Step 5. For systems utilizing type-tested equipment, the time required to complete the CESIR may be reduced. The utility shall complete the CESIR within sixty (60) Business Days, absent extraordinary circumstances, following authorization, receipt of the CESIR fee, and complete information set forth in Step 5. If the applicant fails to provide the utility authorization to proceed, CESIR fee and information requested within thirty (30) Business Days, the interconnection request shall be removed from the queue and no further action on the part of the utility is required.

The applicant and the utility may agree to allow up to an additional forty (40) Business Days beyond the time specified above for completion of the CESIR, provided that no other application is adversely impacted.

Upon completion of the CESIR, the utility will provide the following, in writing, to the applicant:

1. notification of whether the proposed system meets the applicable criteria considered in the CESIR process;
2. utility system impacts, if any;
3. a description of where the proposed system is not in compliance with these requirements;
4. detailed description of reasoning and justification for any system upgrades and associated equipment deemed necessary for interconnection of the project;
5. a good faith, detailed estimate of the total cost of completion of the interconnection of the proposed system and/or a statement of cost responsibility for any system upgrades and associated equipment deemed necessary for interconnection of the project; and
6. a Qualifying Upgrade Disclosure, if applicable

Appendix E sets forth the responsibility each applicant shall have with respect to the actual cost of the system upgrades and equipment necessary for the interconnection of the project. Utility cost estimates provided in the CESIR shall be detailed and broken down by specific equipment requirements, material needs, labor, overhead, and any other categories or efforts incorporated in the estimate. Contingencies associated with the cost estimates shall not exceed 15%.

STEP 7: Applicant Commits to Utility Construction of Utility's System Modifications

The applicant will execute the New York Standardized Interconnection Contract for interconnection and provide the utility with an advance payment of 25% of the utility's estimated costs as identified in Step 6 within the time provided in Section I-D. The utility is not required to procure any equipment or materials associated with the project or begin construction until full payment has been received.

For applications subject to 25% and 75% payment requirements pursuant to Section I-D, the applicant shall provide both an updated three-line diagram and site-specific testing procedures within thirty (30) Business Days of making the 25% payment. For applications that do not require system modifications, a three-line diagram and site-specific testing procedure is required within thirty (30) Business Days after executing the New York State Standardized Interconnection Contract. For applications subject to a single 100% payment requirement under Section I-D, applicants are required to provide a three-line diagram and site-specific testing procedure within thirty (30) Business Days after the 100% payment. Three-line diagrams shall meet utility requirements as specified in Appendix F.

STEP 8: Project Construction

The applicant and the utility shall collaborate to identify an in-service date and develop a project construction schedule (Appendix L). The applicant shall build the facility in accordance with the utility-accepted design and the project schedule. The utility shall commence construction/installation of system modifications in accordance with the project schedule. Utility system modifications will vary in construction time depending on the extent of work and equipment required. The schedule for this work is to be discussed and agreed upon with the applicant in Step 6.

STEP 9: The Applicant's Facility is Tested in Accordance with the Standardized Interconnection Requirements

The verification testing shall be performed by the applicant in accordance with the written test procedure(s) provided by the applicant in Step 7 and any site-specific requirements identified by the utility in Step 6. The final verification testing shall be performed within ten (10) Business Days of notification to the utility by the applicant of complete installation at a mutually agreeable time, and the utility shall be given the opportunity to witness the tests. If the utility opts not to witness the tests, the applicant shall send the utility within five (5) Business Days of completion of such testing a written notification certifying that the system has been installed and tested in compliance with the SIR, the utility accepted design, and the equipment manufacturer's instructions.

STEP 10: Interconnection

The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 9. In addition, the applicant must have complied with and must continue to comply with the contractual and technical requirements.

STEP 11: Final Acceptance and Utility Cost Reconciliation

Except as provided in Appendix E, final project costs shall be reconciled pursuant to this section. If the utility witnessed the verification testing, then, within ten (10) Business Days of the completion of such testing, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the installed DG system, ESS, or Hybrid Project. If the utility did not witness the verification testing, then, within ten (10) Business Days of receiving the written test notification from Step 9, the utility will either issue to the applicant a formal letter of acceptance for interconnection, or will request that the applicant and utility set a date and time to witness operation of the installed DG system, ESS, or Hybrid Project. This witnessed verification testing must be completed within twenty (20) Business Days after being requested. Within ten (10) Business Days of the completion of any such witnessed testing, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the installed DG system, ESS, or Hybrid Project. Within sixty (60) Business Days after issuance of the utility's formal letter of acceptance, or submittal of final as-built drawings to the utility, whichever occurs last, the utility shall prepare and submit to the applicant a final reconciliation statement of its actual costs less any CESIR and construction advance payments made by the applicant. Within twenty (20) Business Days after delivery of the reconciliation statement, the applicant will receive either a bill for any balance due or a reimbursement for overpayment from the utility as determined by the utility's reconciliation. The applicant may contest the reconciliation with the utility. If the utility's final reconciliation invoice states a balance due from the applicant, unless it is challenged by a formal complaint interposed by the applicant, it shall be paid to the utility within thirty (30) Business Days or the utility reserves the right to lock the generating system offline. If the utility's final reconciliation invoice states a reimbursement for overpayment to be paid by the utility, unless the reimbursement amount is challenged by a formal complaint interposed by the applicant, it shall be paid to the applicant within thirty (30) Business Days. If the applicant is not satisfied, a formal complaint may be filed with the Secretary to the Commission.

D. Payment and Construction Milestones

Applicants are responsible for payment of utility system modification cost estimates in accordance with the following rules and deadlines. All project costs will be subject to the provisions of Appendix E, where applicable.

When the utility's estimated cost is $10,000 or less, the applicant shall pay the utility 100% of the estimate within ninety (90) Business Days of receiving the cost estimate from the utility. Within fifteen (15) Business Days of receiving the payment, the utility will provide the applicant, via electronic communication, a signed New York State Standardized Interconnection Contract in the form of Appendix A and a written confirmation, on utility letterhead, of the compensation eligibility for which the project has qualified. The applicant will sign and return the contract to the utility within fifteen (15) Business Days. If the applicant does not return the signed contract within this period, the application shall be removed from the utility's interconnection queue, and no further action on the part of the utility is required.

When the estimated cost is greater than $10,000, the applicant will make an advance payment of 25% of the estimate to the utility within ninety (90) Business Days of receiving the cost estimate. Within fifteen (15) Business Days of receiving the applicant's payment, the utility will provide the applicant, via electronic communication, a receipt for the payment, a signed New York State Standardized Interconnection Contract in the form of Appendix A, and a written confirmation, on utility letterhead, of the compensation eligibility for which the project has qualified. The applicant will sign and return the contract to the utility within fifteen (15) Business Days. The applicant may request an extension of no more than fifteen (15) Business Days to return the contract. If the applicant does not return the signed contract within the time allowed, the application shall be removed from the utility's interconnection queue, and no further action on the part of the utility is required.

Within thirty (30) Business Days of receiving the 25% payment, the utility shall provide an initial construction schedule to the applicant (consistent with Appendix L). The utility shall commence design work in accordance with its published guidance, unless otherwise directed by the applicant.

The applicant will have one hundred and twenty (120) Business Days from when the utility confirms receipt of the 25% payment to pay the remaining 75% to the utility. The utility will provide a receipt to the applicant. Within thirty (30) Business Days of the payment, the utility will provide an updated project construction schedule (consistent with Appendix L).

If the applicant does not make a payment due under this section in the time required, the application shall be removed from the utility's interconnection queue with no further action required of the utility.

Within (10) Business Days of completion of design work, the utility will provide an updated upgrade cost estimate if the scope of work changed from the CESIR estimate.

If the applicant withdraws or is removed from the interconnection queue at any point after making a payment required under this section, any unspent portions of these payments will be refunded to the applicant consistent with the timelines described in Section I-C, Step 11.

If a local permitting moratorium prevents an applicant from meeting the above timelines, the utilities may grant affected project applicants an extension. To be granted an extension of the required timelines, the applicant must submit the New York State Standard Moratorium Attestation Form, Appendix I. Upon the applicant's payment of 25% of expected upgrade costs, if applicant has received its CESIR, returned the executed New York State Standardized Interconnection Contract, and submitted the Attestation Form to the utility, the due date for the remainder of the total upgrade payment shall be adjusted to one hundred and twenty (120) Business Days from the end of the moratorium. If applicable, any unused portion of the 25% payment shall be refunded if the project does not move forward after receiving an extension.

If the final acceptance as set out in Section I-C, Step 11 is not completed within twelve (12) months of the date the applicant returns the executed New York State Standardized Interconnection Contract as a result of applicant inactivity, the utility has the right to notify the applicant by U.S. first class mail with delivery receipt confirmation or via email that the applicant's project will be removed from the utility's interconnection queue if the applicant does not respond within thirty (30) Business Days of the issue of such notification and provide a project status update and/or justification as to why the project should remain in the utility's interconnection inventory for an additional period of time.

E. Application Process for Energy Storage Systems (ESS)

Except as provided in this Section, the rules in Sections I-B and I-C shall apply to applications to: construct new Hybrid Projects; construct new stand-alone storage; add an ESS to an existing DG facility; and change the operating mode of an existing Hybrid Project or stand-alone storage facility. Whether an application will be handled under Section I-B or I-C will be determined by the sum of the AC nameplate ratings of all DG facilities and ESS facilities comprising the proposed Hybrid Project.

STEP 1: The Application

An applicant proposing a Hybrid Project or stand-alone ESS shall complete and submit Appendix K with Appendix F.

The owner of an existing DG facility may apply to add an ESS by submitting a completed Appendix K to the utility at any time.

For all projects involving ESS, the utility shall review the application and respond within the time frames provided in Section I-B or I-C, as applicable.

Following interconnection of a Hybrid Project or a stand-alone ESS, the applicant may apply to the utility to change the operating characteristics of the storage component. To initiate review, the applicant shall submit a completed Appendix K specifying the proposed new operating characteristics to the utility.

STEP 2: Protection and Control Review

When performing screening analysis and system impact studies associated with ESS, operating characteristics including maximum export and import capacity shall be utilized, except that fault current contribution shall be evaluated based on aggregate AC nameplate rating. The utility's technical review shall determine whether the proposed facility, operating per the characteristics identified in the application (Appendix K), can be safely and reliably interconnected to the utility's distribution system. The applicant shall pay the costs for the utility's review in advance.

Following the completion of Step 3 in Section I.B, or upon passing the Preliminary or Supplemental Screening Analysis in Step 4 in Section I.C, based on the application and proposed operating parameters, the utility will determine if a Protection and Control Review is required. The utility will notify the applicant of this determination. The applicant will have thirty (30) Business Days from the notification to pay the nonrefundable fee for the review, which shall be calculated as $500 plus $4/kW capped at $3,000. The utilities shall have twenty (20) Business Days to perform the review and provide the results to the applicant, including a description of any modifications to the control systems that the utility determines are necessary.

Within ten (10) Business Days of an applicant's request, the utility shall discuss the results of the Protection and Control Review. Following the discussion, the applicant will have twenty (20) Business Days to determine whether or not to accept any required modifications to the control system and take the next step in the process as defined in Section I.B or I.C, as applicable, or to withdraw the application.

For all applications relating to ESS, the utility's written report of its technical review shall include a completed Attachment I, as defined below, specifying the operating parameters studied for the proposed facility. The utility and the applicant shall discuss the listed operating parameters promptly after delivery of the study results to the applicant.

For ESS applications requiring a CESIR, the utility will provide the applicant with any additional testing procedures required in connection with the ESS, using the applicant's load management control systems to limit reverse power. The utility will provide this information with the CESIR results.

STEP 3: Contract and Payment for Utility Construction Costs

An applicant proposing a Hybrid Project, stand-alone storage, or the addition of ESS to an existing DG facility shall execute the New York State Standardized Interconnection Contract for Systems including Energy Storage, and make payment to the utility for its estimated construction costs within the time required by Section D.

Each contract shall include a completed Attachment I, which shall specify the operating parameters for the interconnected ESS after consultation with the applicant.

An applicant proposing to change the operating characteristics listed in Appendix K for an existing ESS shall sign an amendment to the New York State Standard Interconnection Contract for Facilities including Energy Storage to incorporate the revised Attachment I and make payment for any utility construction costs within the time required by Section I-D.

F. Rules for Combining DG Applications

Distributed Generation applications that have been determined to be complete and that meet the following criteria may be combined:

(a) the applications must be sequential in the utility's queue on both the circuit and substation bus, or non-sequential combined applications may proceed with the lower queue position;

(b) there can be no non-SIR applications in the utility's queue between the applications that propose to aggregate;

(c) the proposed projects must be located on the same or adjacent parcels;

(d) both applications must be compensated at the same rate and; and

(e) the size of the combined projects may not exceed an AC nameplate rating of 5 MW.

If none of the applications has reached the deadline for payment of 25% of the estimated utility construction costs necessary for its interconnection, the applicant(s) may ask the utility to perform a technical review of the applications as a combined project. The applicant(s) shall submit its request in writing to the utility. The utility shall cease any ongoing work on the individual applications and notify the applicant(s) within ten (10) Business Days of any additional information that is needed to perform the requested analysis and of the fee that will be charged. The utility shall apply any unspent study fees related to the individual applications to the charge for the new study. The applicant(s) shall pay the fee and provide the information sought by the utility within ten (10) Business Days of the notification. The construction cost payment due dates for the applications that are proposed to combine will be suspended until a new due date is established pursuant to this Section.

If any of the applications proposed to be combined has made a payment for estimated utility construction costs, the applicant(s) may still submit a request to study them as a combined project as provided above. Any additional payment due dates associated with the applications shall be suspended until a new due date is established. The utility shall cease work on the individual applications and shall cancel any procurements that the applicant(s) agree should be cancelled. The applicant(s) shall bear any cost associated with such cancellations. The utility shall notify the applicant(s) of any information that is needed to perform the requested analysis and of the fee that will be charged for the study within ten (10) Business Days of receiving the request. The applicant(s) shall pay the fee and provide the information sought by the utility within ten (10) Business Days of the notification.

The utility shall have sixty (60) Business Days from receipt of the fee and the project information to perform the technical review of the combined applications. The utility's report of the results shall provide the information specified in Step 6 of Section I-C to the applicant(s). The applicant(s) may:

(1) proceed to construct the combined project;

(2) resume the interconnection of the separate applications; or

(3) withdraw one or more of the applications.

If the applicant(s) selects option (1), payment for the full amount of the estimated utility construction costs shall be due sixty (60) Business Days after receipt of the results of the technical review. If the applicant(s) selects either option (2) or (3), full payment of the construction cost associated with the applications that are to continue to interconnect shall be due within the same time period. If the applicant(s) does not meet these deadlines, the applications shall be deemed withdrawn with no further action required by the utility.

G. Interconnection On-Line Application Portal (IOAP)

Each utility shall maintain an IOAP system to provide applicants a web-based application submittal process. Hard copy, email, and/or mailed in application will no longer be allowed or accepted unless the utility IOAP systems are down for maintenance or failure. The IOAP shall also provide applicants with updated information regarding the status of their SIR application process. The system shall be customer specific and post the real-time status of the SIR process. At a minimum, the following content shall be provided:

1. The applicant's name and project/application identification number.
2. Description of the project, including at a minimum, the project's type (energy source), size, metering, and location.
3. SIR project application status, including all the steps completed and to be completed, along with corresponding completion/deadline dates associated with each step.
    - If the next action is to be taken by the utility, the expected date that action will be completed,
    - If the next action is to be taken by the applicant, what exactly is required and a contact for more information.
4. Information regarding any outstanding information request made by the utility of the applicant, and
5. The status of all amounts paid and/or due to the utility by the applicant.

Access shall be available for the customer and their authorized agent(s), such that both can access the information. The IOAP must be private and secure from unauthorized access. Access to the IOAP shall be easily found on each electric utility's Interconnection / Distributed Generation home web page.

The IOAP application process must be consistent with the latest version of the SIR and include the ability to attach associated documentation or drawings for each project. Electronic signatures shall be accepted and approved for this process.

H. Modifications

Applicants may propose a Modification at any time by submitting a request to the utility through the utility's on-line application portal and /or via email. Submission of such a request will not suspend any deadlines applicable to the pending application. The utility will review the request to determine whether the proposed Modification is a Material Modification and provide its determination to the applicant within ten (10) Business Days, unless the utility first notifies the applicant that additional information is needed to make the evaluation. In that case, the utility will have ten (10) Business Days from receipt of the additional information to determine whether the proposed Modification is a Material Modification.

A Material Modification to a project will require a new application, a new queue position, and removal of the original application if the applicant elects to move forward with the modification (if not yet interconnected).

The utility reserves the right to make the final determination as to whether a proposed change is a Material Modification.

When making the materiality determination, the utility will consider the DPS Staff posted Guidance Document on DER Material Modifications and will provide the applicant with a written explanation of its finding. At the applicant's request, the utility will meet with the applicant to discuss the materiality determination.

A Modification that is not determined to be material may still require evaluation and acceptance by the utility through the process described below. The applicant is obligated to pay any necessary study costs of the evaluation. The utility will notify the applicant of any additional funding and/or information that may be required to evaluate the Modification within five (5) Business Days of providing the materiality determination. The applicant shall have ten (10) Business Days to provide any requested information and pay the associated fees or choose to remain with the original interconnection application with associated uninterrupted timeline.

If the proposed change is not a Material Modification, and is proposed prior to the start of a CESIR, the utility will study the modified project in the CESIR process.

If the proposed change is not a Material Modification and is proposed following the start of a CESIR but no later than forty (40) Business Days after the start date, the utility may have an additional forty (40) Business Days to complete the CESIR incorporating the change.

If the proposed change is not a Material Modification and is proposed at a later date, or after completion of a CESIR, the change may require further study and will require mutual agreement between the utility and the applicant. The utility retains the right to determine the extent of evaluation necessary but will endeavor to complete any necessary study within a timeframe no longer than a standard CESIR. The applicant will be responsible for any costs related to the change.

Section II. Interconnection Requirements

A. Design Requirements

1. Common

The generator-owner shall provide appropriate protection and control equipment, including a protective device that utilizes an automatic disconnect device that will disconnect the generation in the event that the portion of the utility system that serves the generator is de-energized for any reason or for a fault in the generator-owner's system. The generator-owner's protection and control equipment shall be capable of automatically disconnecting the generation upon detection of an islanding condition and upon detection of a utility system fault.

The type and size of the generation facility or energy storage system is based on electrical generator or inverter AC nameplate rating.

The generator-owner's protection and control scheme shall be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified by the required operating ranges. Upon request from the utility, the generator-owner shall provide documentation detailing compliance with the requirements set forth in this document.

The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the generator-owner's generation, as well the generator-owner's load level, in addition to the characteristics of the particular portion of the utility's system where the generator-owner is interconnecting.

The generator-owner shall have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface shall disconnect for voltage or frequency trip conditions sensed by the protective devices. Voltage protection shall be wired phase to ground for single phase installations and for applications using wye grounded-wye grounded service transformers.

The settings below are listed for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review will be performed by the utility and the revised settings identified in Step 6 of the Application Process.

The requirements set forth in this document are intended to be consistent with those contained in the most current version of IEEE Std 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. The requirements in IEEE Std 1547 above and beyond those contained in this document shall be followed and any other Standards included in or referenced to in IEEE Std 1547 shall be adhered to.

<u>Voltage Response</u>

The required operating range for the generators shall be as detailed in the most current version of IEEE Std 1547 and the Category (related to Area EPS abnormal conditions) as specified by the utility's technical requirements document . In addition, the generator shall not cause the system voltage at the PCC to deviate from a range of 95% to 105% of the utility system voltage. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator-owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functionalities shall be permitted as agreed upon by the utility and generator-owner.

Frequency Response

The required operating range for the generators shall be as detailed in the most current version of IEEE Std 1547 and the Category (related to Area EPS abnormal conditions) as specified by the utility's technical requirements document . If deemed necessary due to abnormal system conditions the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the load shedding schemes of the utility system. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator- owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities shall be permitted as agreed upon by the utility and generator-owner.

Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the generator-owner's equipment shall remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits as defined in the most current version of IEEE Std 1547 for a minimum of five (5) minutes. Systems greater than 25 kW that do not utilize inverter based interface equipment shall not have automatic recloser capability unless otherwise approved by the utility. If the utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

2. Synchronous Generators

Synchronous generation shall require synchronizing facilities. These shall include automatic synchronizing equipment or manual synchronizing with relay supervision, voltage regulator, and power factor control.

For all synchronous generators sufficient reactive power capability shall be provided by the generator-owner to withstand normal voltage changes on the utility's system. The generator voltage VAR schedule, voltage regulator, and transformer ratio settings shall be jointly determined by the utility and the generator-owner to ensure proper coordination of voltages and regulator action. Generator-owners shall have synchronous generator reactive power capability to withstand voltage changes up to 5% of the base voltage levels.

A voltage regulator must be provided and be capable of maintaining the generator voltage under steady state conditions within plus or minus 1.5% of any set point and within an operating range of plus or minus 5% of the rated voltage of the generator.

Generator-owners shall adopt one of the following grounding methods for synchronous generators interconnected to effectively grounded circuits:

a. Solid grounding
b. High- or low-resistance grounding
c. High- or low-reactance grounding
d. Ground fault neutralizer grounding

Synchronous generators shall not be permitted to connect to utility secondary network systems without the acceptance of the utility.

3. Induction Generators

Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the PCC is acceptable based on current inrush limits. The same requirements also apply to induction generation connected at or near synchronous speed because a voltage dip is present due to an inrush of magnetizing current. The generator-owner shall submit the expected number of starts per specific time period and maximum starting kVA draw data to the utility.

Starting or rapid load fluctuations on induction generators can adversely impact the utility's system voltage. Corrective step-switched capacitors or other techniques may be necessary. These measures can, in turn, cause ferro resonance. If these measures are installed on the customer's side of the PCC, the utility will review these measures and may require the customer to install additional equipment.

4. Inverters

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design shall be such as to disconnect this synchronous inverter upon a utility system event. Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in Section II.A.1 shall be provided with the required onboard functionality to allow for the equipment to remain online for the duration of the event.

It is recommended that equipment be selected from the Department of Public Service "Certified Interconnection Equipment list" maintained on the Commission's website. Interconnected DG systems utilizing equipment not found in such list must meet all functional requirements of the current version of IEEE Std 1547 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section.

Synchronization or re-synchronization of an inverter to the utility system shall not result in a voltage deviation that exceeds the requirements contained in Section II.E, Power Quality. Only inverters designed to operate in parallel with the utility system shall be utilized for that purpose.

5. Minimum Protective Function Requirements

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the distributed generation facility

- Voltage level of the interconnection
- Location of the distributed generation facility on the circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the distributed generation facility under isolated conditions
- Amount of existing distributed generation on the local distribution system.

As a result, protection requirements cannot be standardized according to any single criteria. Minimum protective function requirements shall be as detailed in the table below. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points shall be field adjustable.

Synchronous Generators	**Induction Generators**	**Inverters**
Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)
Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)
Anti-Islanding Protection	Anti-Islanding Protection	Anti-Islanding Protection
Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)

For energy storage systems or distributed generation where net export is limited, Reverse Power (Function 32) shall be required.

The need for additional protective functions shall be determined by the utility on a case-by-case basis. If the utility determines a need for additional functions, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, and an explicit justification for the necessity of the enhanced capability. The utility shall specify and provide settings for those functions that the utility designates as being required to satisfy protection practices. Any protective equipment or setting specified by the utility shall not be changed or modified at any time by the generator- owner without written consent from the utility.

The generator-owner shall be responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment. Protective devices shall utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the generator-owner's protective devices, including loss of control power, shall open the automatic disconnect device, thus disconnecting the generation from the utility system. A generator-owner's protection equipment shall utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points.

All interface protection and control equipment shall operate as specified independent of the calendar date.

For monitoring and control of new DG projects, the most current version of the Monitoring and Control Criteria shall be employed by the utilities to evaluate the need for such equipment. The Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG). This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information. The communications hardware, protocols, and data models must comply with utility standards.

6. Metering

Metering requirements shall be determined by the configuration of the DER system. New metering or modifications to existing metering will be reviewed on a case-by-case basis and shall be consistent with metering requirements adopted by the Commission.

Any incremental metering costs are included in interconnection costs that may be required of an applicant.

The following table summarizes the applicable New York Net Metering Rules:

New York (PSL §66-l) - Net Metering*			
Incentive Type:	Net Metering Rules		
Eligible Renewable/Other Technologies:	Wind		
Applicable Sectors:	Residential	Non-Residential	Farm-Service Wind
Limit on System Size:	25 kW	Up to 2 MW	500 kW
Remote Net Metering	No**	Yes	Yes
Limit on Overall Enrollment:	.3% of 2005 Demand per IOU		

* Refer to specific utility tariff leaves for more detailed rules and regulations applicable to net metering wind electric generating systems.

** Residential customers who own or operate a farm operation as defined by Agriculture and Markets Law §301(11) and locate solar photovoltaic, micro-hydroelectric, wind, or fuel cells on property owned or leased by the customer are also eligible for remote net metering.

B. Operating Requirements

The generator-owner shall provide a 24-hour telephone and email/electronic contact. This contact will be used by the utility to arrange access for repairs, inspection, or emergencies. The utility will make such arrangements (except for emergencies) during normal business hours. For all required disconnections of the generator-owner's system to facilitate non-emergency utility work on the electric power system, the utility will provide two (2) Business Days'f advance notice to the generator-owner contact with an indication of anticipated duration.

Voltage and frequency trip set point adjustments shall be accessible to service personnel only. Any changes to these settings must be reviewed and approved by the utility.

The generator-owner shall not supply power to the utility during any outages of the utility system that serves the PCC. The generator-owner's generation may be operated during such outages only with an open tie to the utility. Islanding will not be permitted. The generator-owner shall not energize a de-energized utility circuit for any reason.

Energy storage systems cannot disconnect to self-generate if their operating characteristics require their stored energy to be discharged at that time. All control systems must be password protected from modification by the interconnection customer and property owner following Interconnection.

The disconnect switch specified for system size larger than 25 kW and non-inverter based systems of 25 kW or less in Section II.D, Disconnect Switch, may be opened by the utility at any time for any of the following reasons:

a. to eliminate conditions that constitute a potential hazard to utility personnel or the general public;
b. pre-emergency or emergency conditions on the utility system;
c. a hazardous condition is revealed by a utility inspection; protective device tampering; or,
d. parallel operation prior to utility approval to interconnect.

The disconnect switch may be opened by the utility for the following reasons, after notice to the responsible party has been delivered and a reasonable time to correct (consistent with the conditions) has elapsed:

a. A generator-owner has failed to make available records of verification tests and maintenance of its protective devices;
b. A generator-owner's system adversely impacts the operation of utility equipment

or equipment belonging to other utility customers; or,

c. A generator-owner's system is found to adversely affect the quality of service to adjoining customers.

The utility will provide a name and telephone number so that the generator-owner can obtain information about the utility lock-out.

The generator-owner shall be allowed to disconnect from the utility without prior notice to self-generate.

If a generator-owner proposes any modification to the system that has an impact on the interface at the PCC after it has been installed and a contract between the utility and the generator-owner has already been executed, then any such modifications must be reviewed and approved by the utility before the modifications are made.

C. Dedicated Transformer

The utility reserves the right to require a power-producing facility to connect to the utility system through a dedicated transformer. The transformer shall either be provided by the connecting utility at the generator-owner's expense, purchased from the utility, or conform to the connecting utility's specifications. The transformer that is part of the normal electrical service connection of a generator-owner's facility may meet this requirement if there are no other customers supplied from it. A dedicated transformer is not required if the installation is designed and coordinated with the utility to protect the utility system and its customers adequately from potential detrimental net effects caused by the operation of the generator.

If the utility determines a need for a dedicated transformer, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, the conditions under which the dedicated transformer is expected to enhance safety or prevent detrimental effects, and the expected response of a normal, shared transformer installation to such conditions.

D. Disconnect Switch

Generating equipment with system size larger than 25 kW and non-inverter based systems of 25 kW or less shall be capable of being isolated from the utility system by means of an external, manual, visible, gang-operated, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the customer-generator, and located between the generating equipment and its interconnection point with the utility system.

The disconnect switch must be rated for the voltage and current requirements of the installation.

The basic insulation level (BIL) of the disconnect switch shall be such that it will coordinate with that of the utility's equipment. Disconnect devices shall meet applicable requirements of the most current revision of UL, ANSI, and IEEE standards, and shall be installed to meet all applicable local, state, and federal codes. (New York City Building Code may require additional certification.)

The disconnect switch shall be clearly marked, "Generator Disconnect Switch," with permanent 3/8 inch or larger letters.

The customer-generator will propose, and the utility will approve, the location of the disconnect switch. The location and nature of the disconnect switch shall be indicated in the immediate proximity of the electric service entrance. The disconnect switch shall be readily accessible for operation and locking by utility personnel in accordance with Section II.B, Operating Requirements. The disconnect switch must be lockable in the open position with a 3/8" shank utility padlock.

For installations above 600V or with a full load output of greater than 960A, a draw-out type circuit breaker with the provision for padlocking at the draw-out position will not be an acceptable disconnect switch for the purposes of this requirement unless the use of such a circuit breaker is specifically granted by the utility, based on site-specific technical requirements. If the utility grants such use, the generator-owner will be required, upon the utility's request, to provide qualified operating personnel to open the draw-out circuit breaker and ensure isolation of the DG system, with such operation to be witnessed by the utility followed immediately by the utility locking the device to prevent re-energization. In an emergency or outage situation, where there is no access to the draw- out breaker or no qualified personnel, utilities may disconnect the electric service to the premise in order to isolate the DG system.

E. Power Quality

The requirements for acceptable flicker levels shall be in accordance with the latest version of IEEE Std 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker shall be within the planning and compatibility levels delineated in this standard. Mitigation measures necessary to comply with these requirements shall at the generator-owner's expense.

F. Power Factor

If the average power factor, as measured at the PCC, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator will be negotiated with the utility as a commercial item. If the average power factor of the generator is proven to be above the minimum of 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor value shall be used for any further utility design calculations and requirements.

Induction power generators may be provided VAR capacity from the utility system at the generator-owner's expense. The installation of VAR correction equipment by the generator-owner on the generator-owner's side of the PCC must be reviewed and approved by the utility prior to installation.

G. Islanding

Systems must be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The requirements listed in this document are designed and intended to prevent islanding. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

For inverter based systems, evaluation of the need for special measures to prevent unintentional islanding on radial distribution systems should be based on best practices related to the most current version of the Unintentional Islanding Protection Practice Connected to the

Distribution System. This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

The need for zero sequence voltage (3V0) and direct transfer trip (DTT) protection schemes shall be evaluated based on minimum loads on the associated feeder and substation bus, including certain fault conditions resulting from system installation to protect for an islanded condition.

H. Equipment Certification

In order for the equipment to be acceptable for interconnection to the utility system without additional protective devices, the interface equipment must be equipped with the minimum protective function requirements listed in the table in Section II.A.5 and be tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in compliance with the most current revision of UL 1741, including supplement B (UL 1741 SB) , with settings as specified in the utility's technical requirements document .

For each interconnection application, documentation including the proposed equipment certification, stating compliance with the most recent version of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document , by an NRTL, shall be provided by the applicant to the utility. Supporting information from an NRTL website or UL's website stating compliance is acceptable for documentation.

If an equipment manufacturer, vendor, or any other party desires, documentation indicating compliance as stated above may be submitted to the Department of Public Service for listing under the certified equipment list on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab.

Certification information for equipment tested and certified to the most current revision of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document , by a non-NRTL shall be provided by the manufacturer, or vendor, to the contacts listed on the Department of Public Service website for review before final acceptance and posting under the certified equipment list. Utilities are not responsible for reviewing and approving equipment tested and certified by a non-NRTL.

If a NRTL certifies equipment to the most current version of UL 1741, including UL 1741 SB , with settings as specified in the utility's technical requirements document , and compliance documentation is submitted to the utility, the utility shall accept such equipment for interconnection in New York State. All equipment certified to the most current revision of UL 1741, including UL 1741 SB , with settings as specified in the utility's technical requirements document , by an NRTL shall be deemed 'certified equipment' even if it does not appear on the Commission's website under the Certified Equipment list.

Utility grade relays need not be certified per the requirements of this section.

For DG systems that are already interconnected with the utility's electrical system and seek to use the New York State Standardized Interconnection Requirements and Application Process in order to qualify for net metering, no DG system will be required to obtain recertification the latest equipment certification standards, as long as the DG system met the equipment certification requirements by the utility in effect at the time of the DG unit's interconnection.

I. Verification Testing

All interface equipment must include a verification test procedure as part of the documentation presented to the utility in the course of the interconnection process. Except for the case of small single-phase inverters as discussed later, the verification test must establish that the protection settings meet the SIR requirements. The verification testing may be site-specific and is performed periodically to assure continued acceptable performance.

Upon initial parallel operation of a generating system, or any time interface hardware or software is changed, the verification test must be performed. A qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory-trained and certified technicians, and licensed electricians with experience in testing protective equipment. The utility reserves the right to witness verification testing or require written certification that the testing was successfully performed.

Verification testing shall be performed at least once every four years. All verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The generator-owner shall maintain verification test reports for inspection by the utility.

Single-phase inverters and inverter systems rated 25 kW and below shall be verified upon initial parallel operation and once every four years as follows: the generator-owner shall interrupt the utility source and verify that the equipment automatically disconnects and does not reconnect for at least five minutes after the utility source is reconnected. The owner shall maintain a log of these operations for inspection by the connecting utility. Any system that depends upon a battery for trip power shall be checked and logged at least annually for proper voltage. Once every four (4) years the battery must be either replaced or a discharge test performed.

J. Interconnection Inventory

The utilities will manage the queue of interconnection applications in their inventories in the order in which they are received and according to the timelines set forth in this document.

To ensure applications are addressed in a timely manner and monitor the overall interconnection activities, utilities shall submit an SIR inventory of projects monthly to the Public Service Commission by the 15th day of the following month. Therefore, 12 interconnection inventory submissions shall be provided each year by each of the electric utilities. Utilities shall provide DPS Staff with redacted and unredacted versions of its interconnection inventory, including the current queue, for the associated time period in Excel format. At a minimum, the following information shall be provided in the inventory:

1. Utility Name
2. Applicant Name
3. Developer
4. Application No.
5. Circuit ID
6. Substation
7. System Type
8. System Capacity
9. Metering Configuration

10. Protective Equipment
11. Application Review Start and End date
12. Preliminary Screening Analysis Start and End date
13. CESIR Start and End date
14. CESIR Costs
15. Utility CESIR Costs
16. Customer CESIR Costs
17. Utility System Upgrade Costs
18. Customer System Upgrade Costs
19. Verification Testing date
20. Final Letter of Acceptance date

Exhibit 7

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< News

Con Edison and O&R Utilities Seeking Battery Projects to Aid Clean Energy Push

CON EDISON MEDIA RELATIONS | New York – August 02, 2021 -- 12:30 PM

Con Edison of New York and its affiliate Orange & Rockland (O&R) are looking for developers who can place large battery storage systems in New York City and four counties to the north.

The companies have released a request for proposals for developers interested in building battery systems that can go into operation by the end of 2025.

conEdison

Con Edison senior engineers Steven Goldman (left) and Jorge Tua (right) inside a company battery storage unit in Ozone Park, Queens.

Energy storage is part of the New York State and New York City environmental plans, which Con Edison Inc. supports. Batteries make it possible to store electricity created by renewable resources such as solar farms and windmills and provide that energy to customers when they need it.

"We want to build on the momentum from our first request and help New York State move closer to its battery storage goals," said Leonard Singh, senior vice president, Customer Energy Solutions, for Con Edison. "Our battery projects and the transmission lines we are building will maximize the environmental benefits from the renewable energy that will join New York State's portfolio."

"Energy storage plays an important role in our concerted efforts to provide reliable and resilient power to our customers while minimizing its overall cost,"

conEdison

O&R's President and CEO Robert Sanchez, left, leads an inspection through O&R's new battery storage facility in Pomona last spring. In addition to Sanchez, the group includes, from left: O&R V.P. Operations Orville Cocking, O&R Project Manager MD Sakib and COO and Co-Founder of Key Capture Energy, the project's developer, Dan Fitzgerald.

Energy storage can draw power from the grid when the demand for power is low and less expensive. It can discharge that power at times when the demand for power is high, decreasing the need for power from fossil fuel-fired plants.

Utility-scale energy storage will grow in importance with the planned addition of large amounts of renewable energy in New York State, including 6,000 megawatts of solar and 9,000 megawatts from offshore wind.

projects totaling 10 megawatts.

Developers that respond to the request can propose one project or multiple projects. Each project must be more than 5 megawatts.

The projects must connect to the Con Edison or O&R transmission or distribution systems. Developers will own, operate and maintain the storage systems and enter contracts of up to 10 years with Con Edison or O&R, agreeing to let the utility bid services from the systems into the state's wholesale market.

The New York State Public Service Commission (NYSPSC) last month approved a plan by Con Edison and partner 174 Power Global for a 100-megawatt battery project at the site of the former Charles Poletti natural gas-fired plant in Astoria, Queens. That project near the East River will be complete by the end of 2022 and will be the largest storage facility in New York State.

The Astoria project is the result of a request for proposals that Con Edison issued in 2019.

In April, O&R began operating its first battery energy storage project, a 3-megawatt battery storage array in Rockland County, marking a significant milestone in the growth of energy storage capacity in New York's Hudson Valley.

The battery storage project is part of O&R's program to reduce costs to customers and incorporate new technologies to maintain efficient, resilient and reliable electric operations.

Consolidated Edison, Inc. is one of the nation's largest investor-owned energy-delivery companies, with approximately $12 billion in annual revenues and $62 billion in assets. The company provides a wide range of energy-related products and services to its customers through the following subsidiaries: Consolidated

conEdison

Manhattan, the Bronx, parts of Queens and parts of Westchester, and steam service in Manhattan; Orange and Rockland Utilities, Inc. (O&R), a regulated utility serving customers in a 1,300-square-mile-area in southeastern New York State and northern New Jersey; Con Edison Clean Energy Businesses, Inc., the second-largest solar developer in the United States and the seventh-largest worldwide, which, through its subsidiaries develops, owns and operates renewable and sustainable energy infrastructure projects and provides energy-related products and services to wholesale and retail customers; and Con Edison Transmission, Inc., which falls primarily under the oversight of the Federal Energy Regulatory Commission and through its subsidiaries invests in electric transmission projects supporting its parent company's effort to transition to clean, renewable energy. Con Edison Transmission manages, through joint ventures, both electric and gas assets while seeking to develop electric transmission projects that will bring clean, renewable electricity to customers, focusing on New York, New England, the Mid-Atlantic states and the Midwest.

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Exhibit 8

Con Edison Demand Response Programs

Commercial System Relief Program (21 Hour Notification Program)

Event Call Windows for 2024

Customers participating in CSRP will be asked to reduce their energy use during a four-hour long call window period, which generally corresponds with the network's peak loading period. Each network falls within one of four fixed call windows: 11:00 AM - 3:00 PM, 2:00 PM - 6:00 PM, 4:00 PM - 8:00 PM, and 7:00 PM - 11:00 PM. Advisory notice of a CSRP event will be provided at least 21 hours in advance and confirmed or canceled at least two hours before the start time of an event.

Table 1 lists Con Edison networks by demand response event call window. Table 2 lists the same information by borough.

Please note that a number of networks have new call window assignments for 2024. These changes were made to better align the call windows with the observed network load peaks. Please take note of these changes for the 2024 season and ensure that all participants and stakeholders are aware of their newly assigned call windows.

Network boundaries are typically different from neighborhood borders. For example, the Richmond Hill network includes parts of Brooklyn and Queens. Current Aggregators and Direct Enroll customers should use the Network Lookup tool in the DR/SUR Portal to confirm the assigned network and call window. If you have further questions, please email the Con Edison Demand Response team at demandresponse@coned.com

Commercial System Relief Program (21 Hour Notification Program)
Event Call Windows for 2024

Table 1: Networks by Event Call Window

11:00 AM - 3:00 PM	2:00 PM - 6:00 PM	4:00 PM - 8:00 PM	7:00 PM - 11:00 PM
BOWLING GREEN	BATTERY PARK CITY	BUCHANAN	CROWN HEIGHTS
CORTLANDT	BAY RIDGE	CEDAR ST.	RANDALL'S ISLAND
FREEDOM	BEEKMAN	CENTRAL BRONX	RICHMOND HILL
FULTON	BORDEN	CENTRAL PARK	RIDGEWOOD
GRAND CENTRAL	BOROUGH HALL	ELMSFORD #2	
GREELEY SQUARE	BRIGHTON BEACH	FLATBUSH	
HERALD SQUARE	CANAL	FLUSHING	
HUNTER	CHELSEA	FORDHAM	
KIPS BAY	CITY HALL	FOX HILLS	
PARK PLACE	COLUMBUS CIRCLE	FRESH KILLS	
PENNSYLVANIA	COOPER SQUARE	GRANITE HILL	
PLAZA	EMPIRE	JACKSON HEIGHTS	
SUTTON	FASHION	JAMAICA	
TIMES SQUARE	GRASSLANDS	MASPETH	
TURTLE BAY	GREENWICH	MOHANSIC	
	HARLEM	NORTHEAST BRONX	
	HARRISON	OSSINING WEST	
	HUDSON	PARK SLOPE	
	LENOX HILL	PROSPECT PARK	
	LINCOLN SQUARE	REGO PARK	
	LONG ISLAND CITY	RIVERDALE	
	MADISON SQUARE	ROCKVIEW	
	MIDTOWN WEST	SHEEPSHEAD BAY	
	MILLWOOD WEST	SOUTHEAST BRONX	
	OCEAN PARKWAY	SUNNYSIDE	
	PLEASANTVILLE	WAINWRIGHT	
	ROCKEFELLER CENTER	WASHINGTON HEIGHTS	
	ROOSEVELT	WASHINGTON ST.	
	SHERIDAN SQUARE	WEST BRONX	
	TRIBORO	WILLOWBROOK	
	WHITE PLAINS	WOODROW	
	WILLIAMSBURG		
	YORKVILLE		

Commercial System Relief Program (21 Hour Notification Program)
Event Call Windows for 2024

Table 2: Network Event Call Windows by Borough

Borough	Network	Event Call Window
Bronx	CENTRAL BRONX	4:00 PM – 8:00 PM
Bronx	FORDHAM	4:00 PM – 8:00 PM
Bronx	NORTHEAST BRONX	4:00 PM – 8:00 PM
Bronx	RIVERDALE	4:00 PM – 8:00 PM
Bronx	SOUTHEAST BRONX	4:00 PM – 8:00 PM
Bronx	WEST BRONX	4:00 PM – 8:00 PM
Brooklyn	BAY RIDGE	2:00 PM – 6:00 PM
Brooklyn	BOROUGH HALL	2:00 PM – 6:00 PM
Brooklyn	BRIGHTON BEACH	2:00 PM – 6:00 PM
Brooklyn	CROWN HEIGHTS	7:00 PM – 11:00 PM
Brooklyn	FLATBUSH	4:00 PM – 8:00 PM
Brooklyn	OCEAN PARKWAY	2:00 PM – 6:00 PM
Brooklyn	PARK SLOPE	4:00 PM – 8:00 PM
Brooklyn	PROSPECT PARK	4:00 PM – 8:00 PM
Brooklyn	RIDGEWOOD	7:00 PM – 11:00 PM
Brooklyn	SHEEPSHEAD BAY	4:00 PM – 8:00 PM
Brooklyn	WILLIAMSBURG	2:00 PM – 6:00 PM
Manhattan	BATTERY PARK CITY	2:00 PM – 6:00 PM
Manhattan	BEEKMAN	2:00 PM – 6:00 PM
Manhattan	BOWLING GREEN	11:00 AM – 3:00 PM
Manhattan	CANAL	2:00 PM – 6:00 PM
Manhattan	CENTRAL PARK	4:00 PM – 8:00 PM
Manhattan	CHELSEA	2:00 PM – 6:00 PM
Manhattan	CITY HALL	2:00 PM – 6:00 PM
Manhattan	COLUMBUS CIRCLE	2:00 PM – 6:00 PM
Manhattan	COOPER SQUARE	2:00 PM – 6:00 PM
Manhattan	CORTLANDT	11:00 AM – 3:00 PM
Manhattan	EMPIRE	2:00 PM – 6:00 PM
Manhattan	FASHION	2:00 PM – 6:00 PM
Manhattan	FREEDOM	11:00 AM – 3:00 PM
Manhattan	FULTON	11:00 AM – 3:00 PM
Manhattan	GRAND CENTRAL	11:00 AM – 3:00 PM
Manhattan	GREELEY SQUARE	11:00 AM – 3:00 PM
Manhattan	GREENWICH	2:00 PM – 6:00 PM
Manhattan	HARLEM	2:00 PM – 6:00 PM
Manhattan	HERALD SQUARE	11:00 AM – 3:00 PM
Manhattan	HUDSON	2:00 PM – 6:00 PM
Manhattan	HUNTER	11:00 AM – 3:00 PM
Manhattan	KIPS BAY	11:00 AM – 3:00 PM
Manhattan	LENOX HILL	2:00 PM – 6:00 PM

Manhattan	LINCOLN SQUARE	2:00 PM – 6:00 PM
Manhattan	MADISON SQUARE	2:00 PM – 6:00 PM
Manhattan	MIDTOWN WEST	2:00 PM – 6:00 PM
Manhattan	PARK PLACE	11:00 AM – 3:00 PM
Manhattan	PENNSYLVANIA	11:00 AM – 3:00 PM
Manhattan	PLAZA	11:00 AM – 3:00 PM
Manhattan	RANDALL'S ISLAND	7:00 PM – 11:00 PM
Manhattan	ROCKEFELLER CENTER	2:00 PM – 6:00 PM
Manhattan	ROOSEVELT	2:00 PM – 6:00 PM
Manhattan	SHERIDAN SQUARE	2:00 PM – 6:00 PM
Manhattan	SUTTON	11:00 AM – 3:00 PM
Manhattan	TIMES SQUARE	11:00 AM – 3:00 PM
Manhattan	TRIBORO	2:00 PM – 6:00 PM
Manhattan	TURTLE BAY	11:00 AM – 3:00 PM
Manhattan	WASHINGTON HEIGHTS	4:00 PM – 8:00 PM
Manhattan	YORKVILLE	2:00 PM – 6:00 PM
Queens	BORDEN	2:00 PM – 6:00 PM
Queens	FLUSHING	4:00 PM – 8:00 PM
Queens	JACKSON HEIGHTS	4:00 PM – 8:00 PM
Queens	JAMAICA	4:00 PM – 8:00 PM
Queens	LONG ISLAND CITY	2:00 PM – 6:00 PM
Queens	MASPETH	4:00 PM – 8:00 PM
Queens	REGO PARK	4:00 PM – 8:00 PM
Queens	RICHMOND HILL	7:00 PM – 11:00 PM
Queens	SUNNYSIDE	4:00 PM – 8:00 PM
Staten Island	FOX HILLS	4:00 PM – 8:00 PM
Staten Island	FRESH KILLS	4:00 PM – 8:00 PM
Staten Island	WAINWRIGHT	4:00 PM – 8:00 PM
Staten Island	WILLOWBROOK	4:00 PM – 8:00 PM
Staten Island	WOODROW	4:00 PM – 8:00 PM
Westchester	BUCHANAN	4:00 PM – 8:00 PM
Westchester	CEDAR ST.	4:00 PM – 8:00 PM
Westchester	ELMSFORD #2	4:00 PM – 8:00 PM
Westchester	GRANITE HILL	4:00 PM – 8:00 PM
Westchester	GRASSLANDS	2:00 PM – 6:00 PM
Westchester	HARRISON	2:00 PM – 6:00 PM
Westchester	MILLWOOD WEST	2:00 PM – 6:00 PM
Westchester	MOHANSIC	4:00 PM – 8:00 PM
Westchester	OSSINING WEST	4:00 PM – 8:00 PM
Westchester	PLEASANTVILLE	2:00 PM – 6:00 PM
Westchester	ROCKVIEW	4:00 PM – 8:00 PM
Westchester	WASHINGTON ST.	4:00 PM – 8:00 PM
Westchester	WHITE PLAINS	2:00 PM – 6:00 PM

Commercial System Relief Program (21 Hour Notification Program)
Event Call Windows for 2024

For the 2024 DR season, 22 networks have moved to new call windows to better align with their respective network load peak. Please note these changes in Tables 3 and 4 below.

Table 3: Networks with New Call Windows versus 2023 by Borough

Borough	Network	Event Call Window
Bronx	CENTRAL BRONX	4:00 PM – 8:00 PM
Brooklyn	CROWN HEIGHTS	7:00 PM – 11:00 PM
Brooklyn	PARK SLOPE	4:00 PM – 8:00 PM
Brooklyn	RIDGEWOOD	7:00 PM – 11:00 PM
Brooklyn/Queens	RICHMOND HILL	7:00 PM – 11:00 PM
Manhattan	BEEKMAN	2:00 PM – 6:00 PM
Manhattan	CENTRAL PARK	4:00 PM – 8:00 PM
Manhattan	CITY HALL	2:00 PM – 6:00 PM
Manhattan	COLUMBUS CIRCLE	2:00 PM – 6:00 PM
Manhattan	FASHION	2:00 PM – 6:00 PM
Manhattan	HUNTER	11:00 AM – 3:00 PM
Manhattan	KIPS BAY	11:00 AM – 3:00 PM
Manhattan	LENOX HILL	2:00 PM – 6:00 PM
Manhattan	LINCOLN SQUARE	2:00 PM – 6:00 PM
Manhattan	MIDTOWN WEST	2:00 PM – 6:00 PM
Manhattan	ROCKEFELLER CENTER	2:00 PM – 6:00 PM
Manhattan	WASHINGTON HEIGHTS	4:00 PM – 8:00 PM
Queens	FLUSHING	4:00 PM – 8:00 PM
Westchester	CEDAR ST.	4:00 PM – 8:00 PM
Westchester	ELMSFORD #2	4:00 PM – 8:00 PM
Westchester	MILLWOOD WEST	2:00 PM – 6:00 PM
Westchester	PLEASANTVILLE	2:00 PM – 6:00 PM

Commercial System Relief Program (21 Hour Notification Program)
Event Call Windows for 2024

Table 4: Networks with New Call Windows versus 2023

11:00 AM - 3:00 PM	2:00 PM - 6:00 PM	4:00 PM - 8:00 PM	7:00 PM - 11:00 PM
HUNTER	BEEKMAN	CENTRAL BRONX	CROWN HEIGHTS
KIPS BAY	CITY HALL	PARK SLOPE	RIDGEWOOD
	COLUMBUS CIRCLE	CENTRAL PARK	RICHMOND HILL
	FASHION	WASHINGTON HEIGHTS	
	LENOX HILL	FLUSHING	
	LINCOLN SQUARE	CEDAR ST.	
	MIDTOWN WEST	ELMSFORD #2	
	ROCKEFELLER CENTER		
	MILLWOOD WEST		
	PLEASANTVILLE		

Commercial System Relief Program (21 Hour Notification Program)
Event Call Windows for 2024

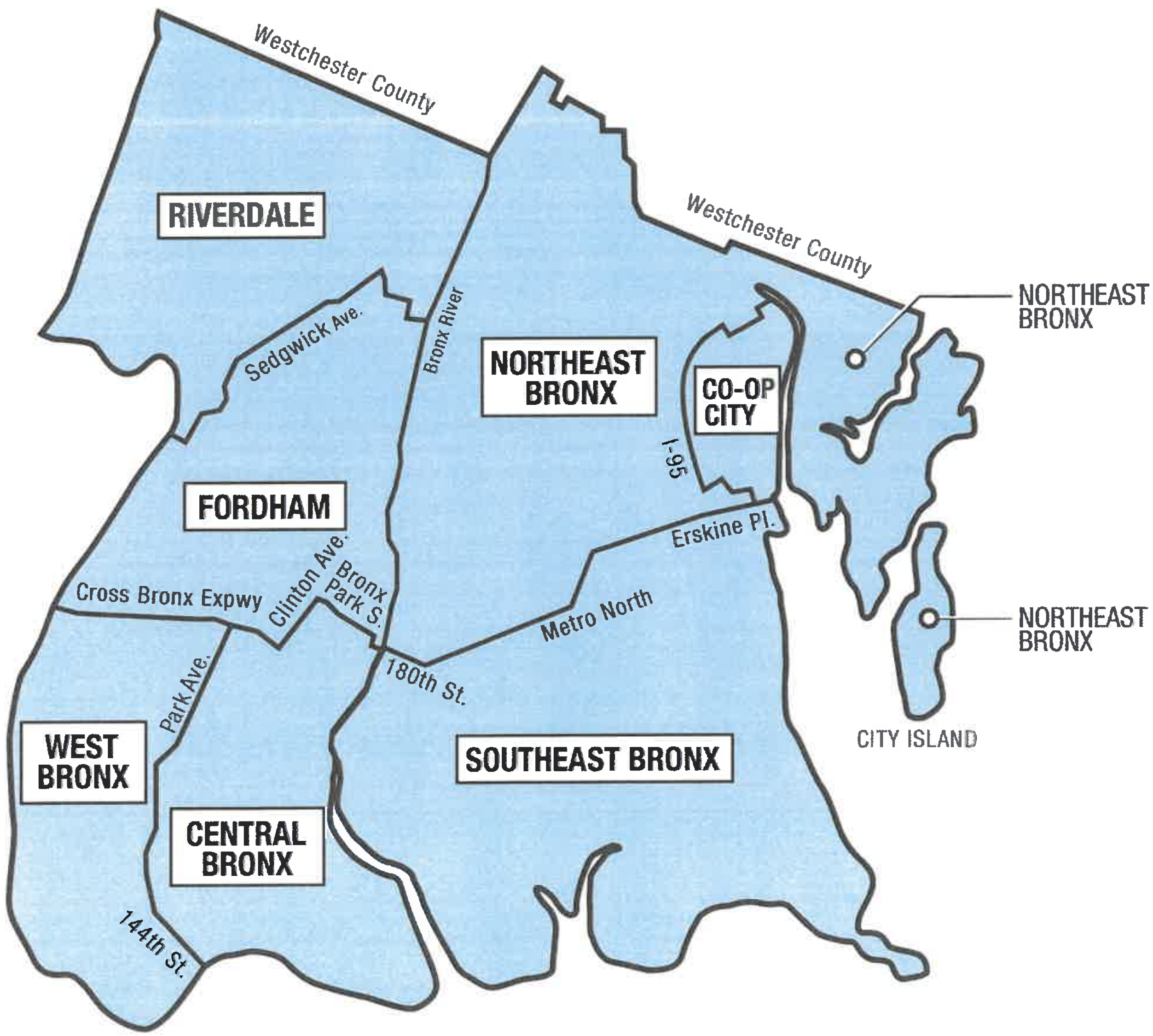
For the 2024 DR season, 18 networks with the 6 Hour CSRP Response Period, which includes the one hour prior to and one hour after the CSRP Call Window

Table 5: Networks with the 6 Hour CSRP Response Period

Borough	Network	Event Call Window
Manhattan	BEEKMAN	2:00 PM – 6:00 PM
Manhattan	BOWLING GREEN	11:00 AM – 3:00 PM
Manhattan	CITY HALL	2:00 PM – 6:00 PM
Brooklyn	FLATBUSH	4:00 PM – 8:00 PM
Manhattan	GREELEY SQUARE	11:00 AM – 3:00 PM
Manhattan	HERALD SQUARE	11:00 AM – 3:00 PM
Manhattan	HUNTER	11:00 AM – 3:00 PM
Queens	JACKSON HEIGHTS	4:00 PM – 8:00 PM
Queens	JAMAICA	4:00 PM – 8:00 PM
Manhattan	LENOX HILL	2:00 PM – 6:00 PM
Queens	LONG ISLAND CITY	2:00 PM – 6:00 PM
Manhattan	MIDTOWN WEST	2:00 PM – 6:00 PM
Manhattan	PARK PLACE	11:00 AM – 3:00 PM
Manhattan	PLAZA	11:00 AM – 3:00 PM
Queens	REGO PARK	4:00 PM – 8:00 PM
Bronx	SOUTHEAST BRONX	4:00 PM – 8:00 PM
Manhattan	SUTTON	11:00 AM – 3:00 PM
Manhattan	TURTLE BAY	11:00 AM – 3:00 PM

Bronx Map

	11a.m. - 3p.m.	(11:00 - 15:00)
	2p.m. - 6p.m.	(14:00 - 18:00)
	4p.m. - 8p.m.	(16:00 - 20:00)
	7p.m. - 11p.m.	(19:00 - 23:00)



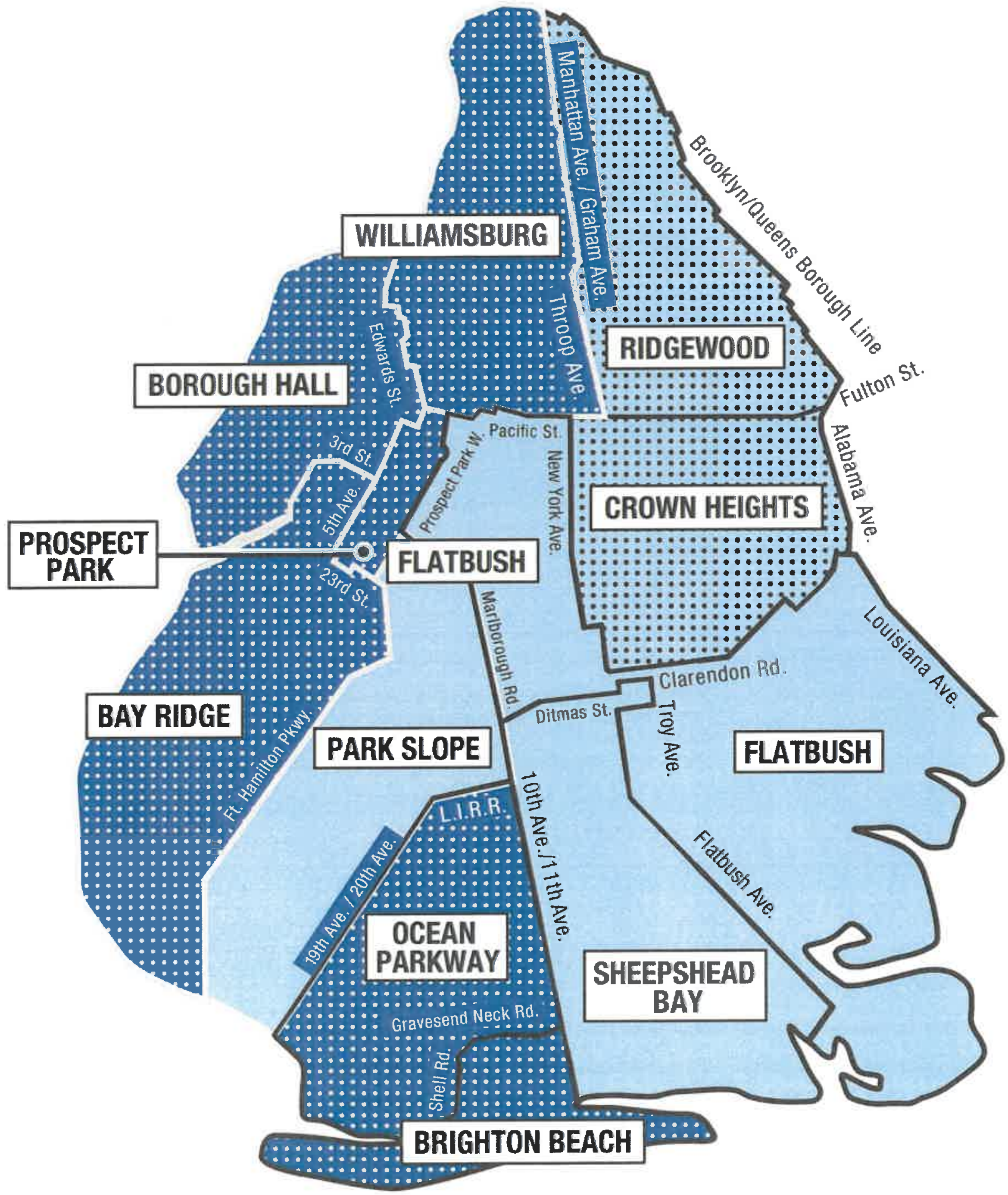
Notes: All boundaries are approximate.

Certain northern portions of Riverdale may be part of the Granite Hill network in Westchester.

Certain northern portions of the Northeast Bronx network may be part of the Washington Street network in Westchester.

Brooklyn Map

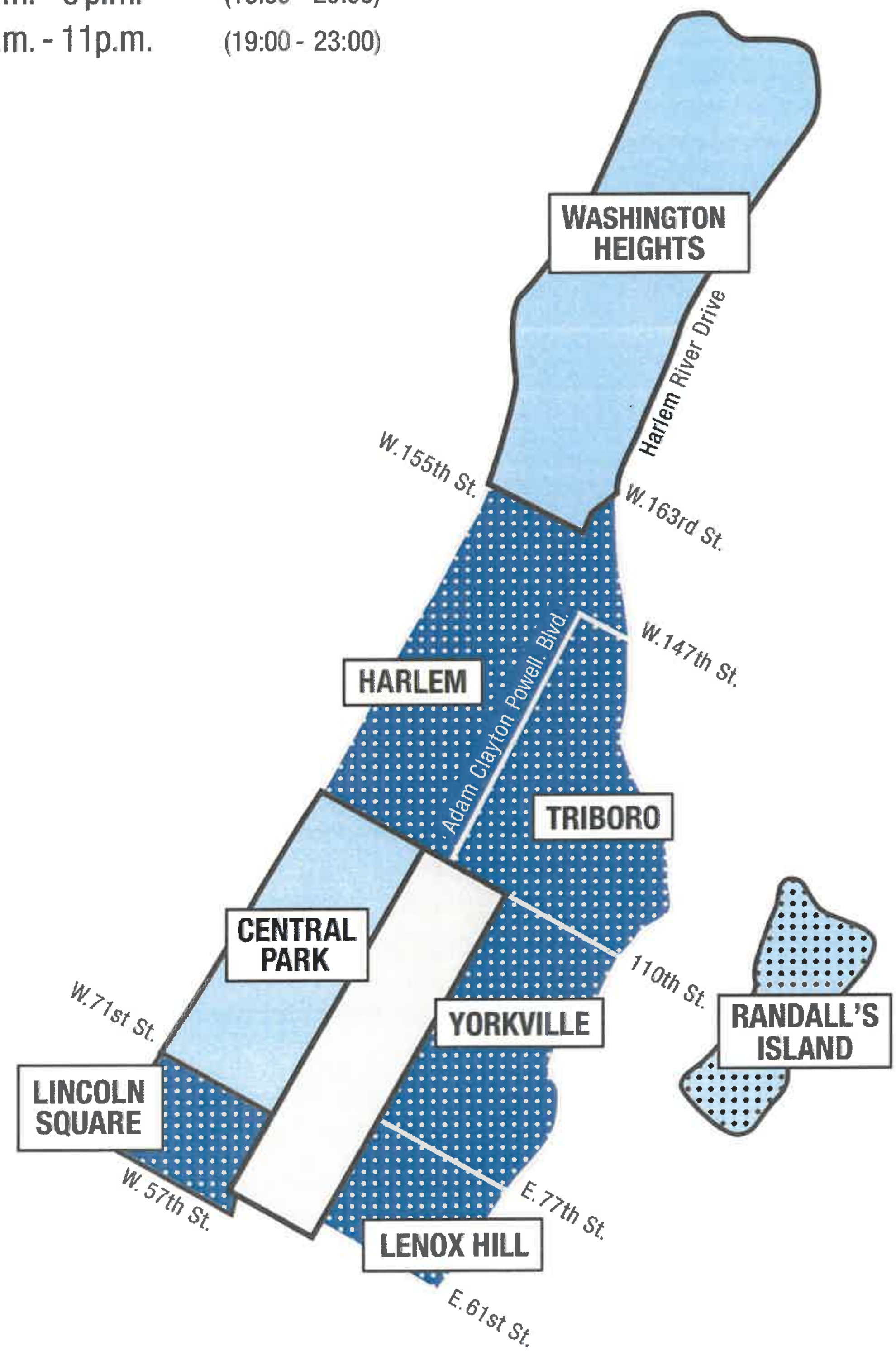
	11a.m. - 3p.m.	(11:00 - 15:00)
	2p.m. - 6p.m.	(14:00 - 18:00)
	4p.m. - 8p.m.	(16:00 - 20:00)
	7p.m. - 11p.m.	(19:00 - 23:00)



Notes: All boundaries are approximate.
Part of northeast Brooklyn is in the Richmond Hill network, which is displayed on the Queens map.

Manhattan (North) Map

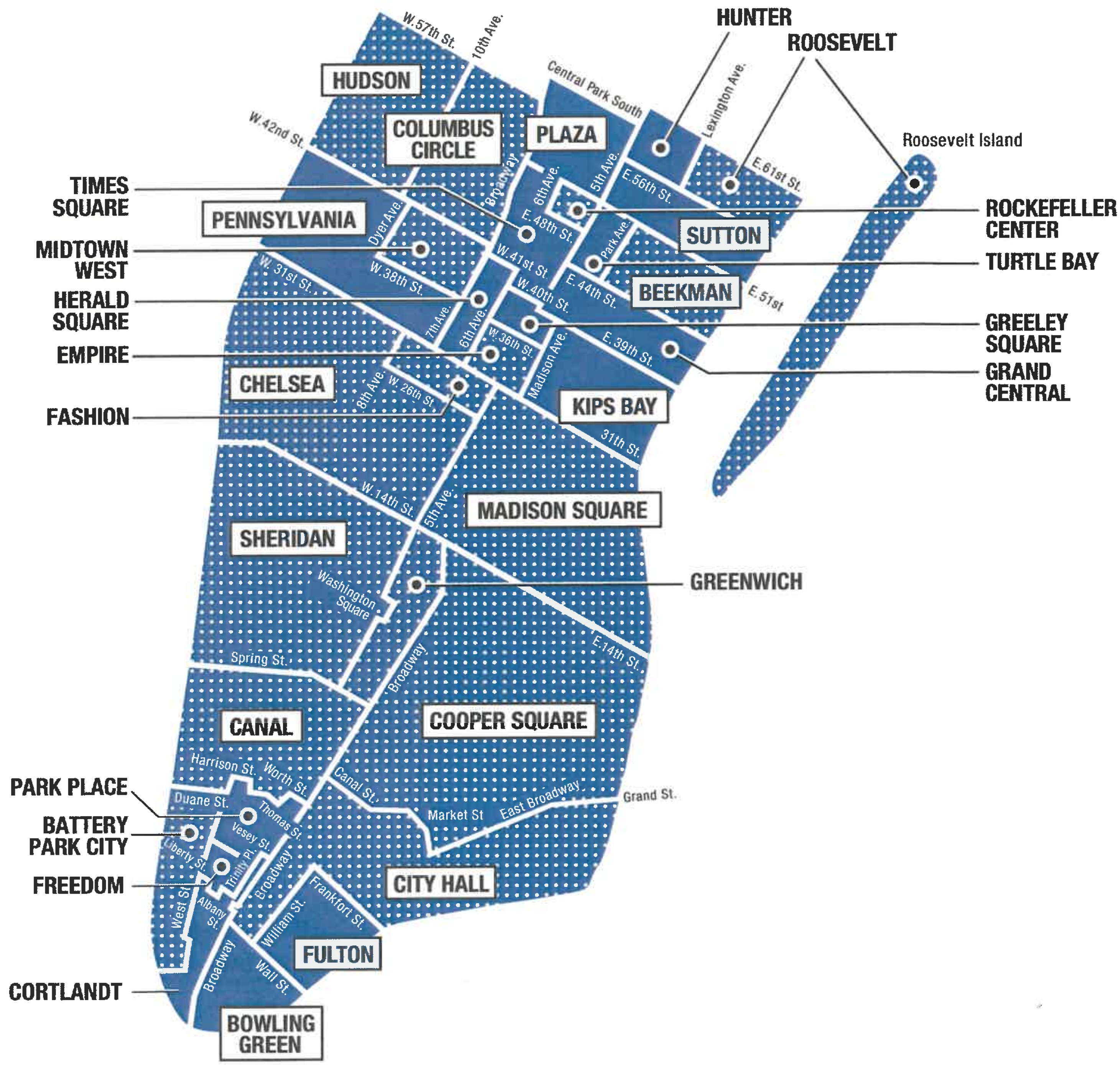
11a.m. - 3p.m.	(11:00 - 15:00)
2p.m. - 6p.m.	(14:00 - 18:00)
4p.m. - 8p.m.	(16:00 - 20:00)
7p.m. - 11p.m.	(19:00 - 23:00)



Note: All boundaries are approximate.

Manhattan (South) Map

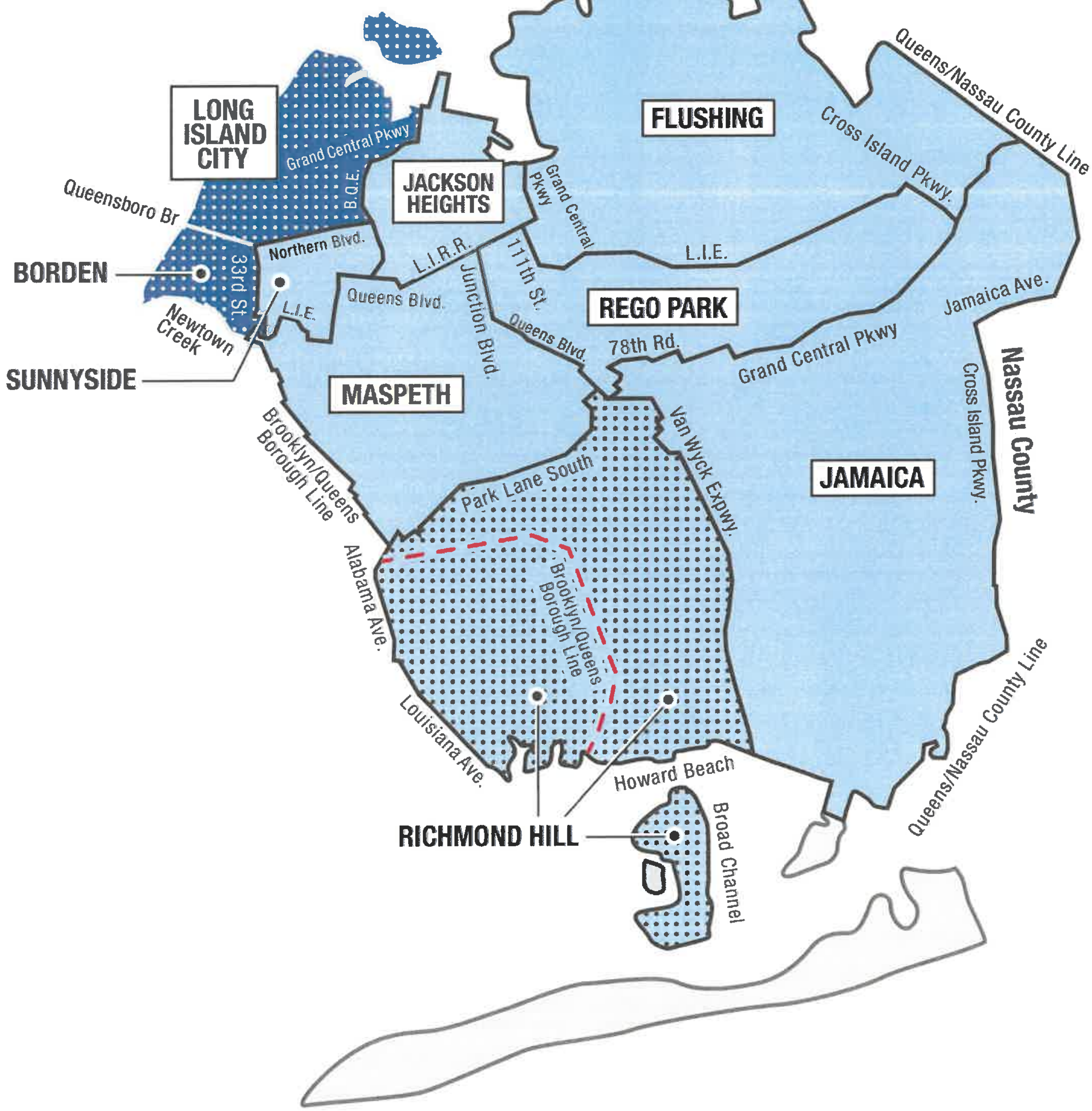
■	11 a.m. - 3 p.m.	(11:00 - 15:00)
▦	2 p.m. - 6 p.m.	(14:00 - 18:00)
□	4 p.m. - 8 p.m.	(16:00 - 20:00)
▦	7 p.m. - 11p.m.	(19:00 - 23:00)



Notes: All boundaries are approximate

Queens Map

11 a.m. - 3 p.m.	(11:00 - 15:00)
2 p.m. - 6 p.m.	(14:00 - 18:00)
4 p.m. - 8 p.m.	(16:00 - 20:00)
7 p.m. - 11p.m.	(19:00 - 23:00)

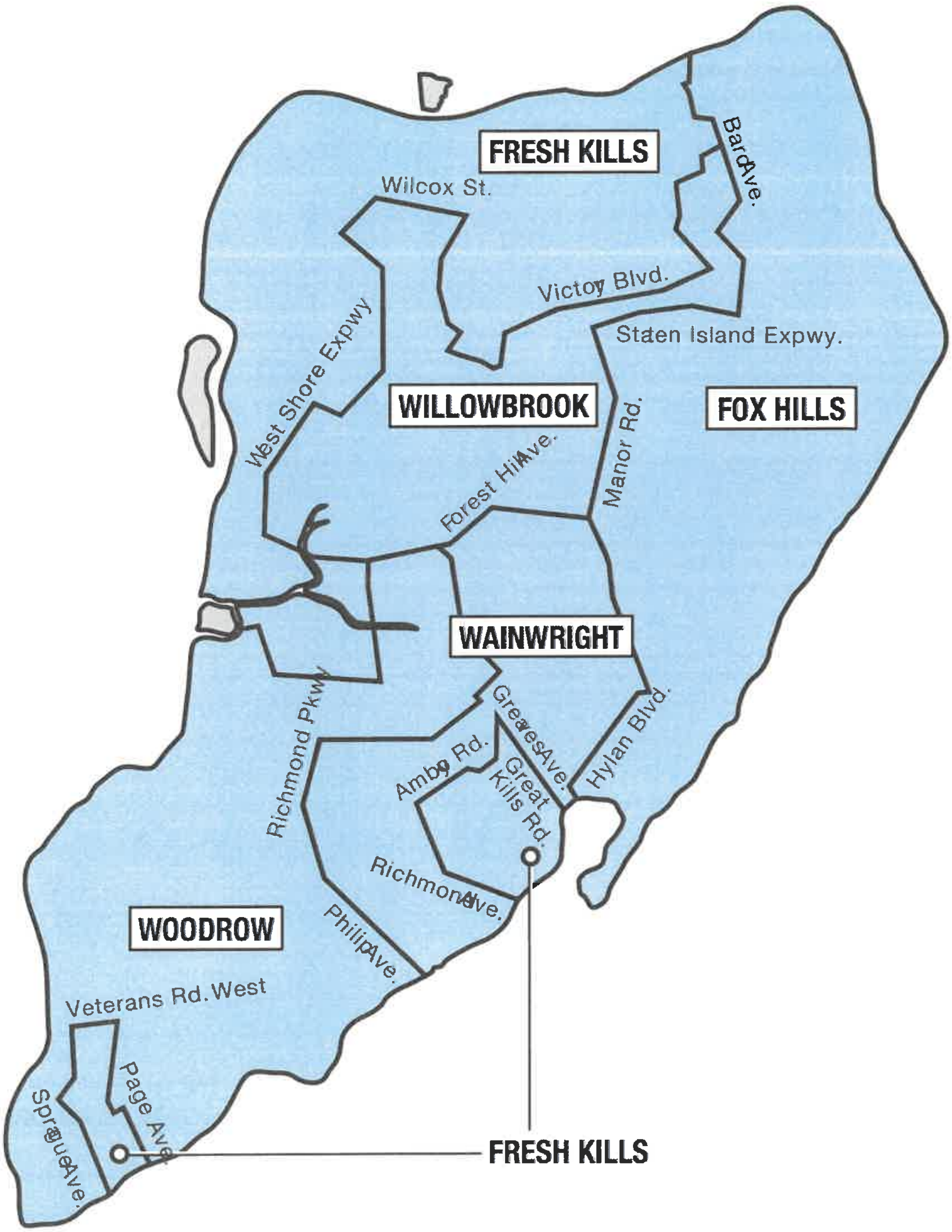


Notes: All boundaries are approximate
Far Rockaway is not part of the Con Edison service territory. This area is serviced by PSEG Long Island/LIPA.

Staten Island Map

conEdison

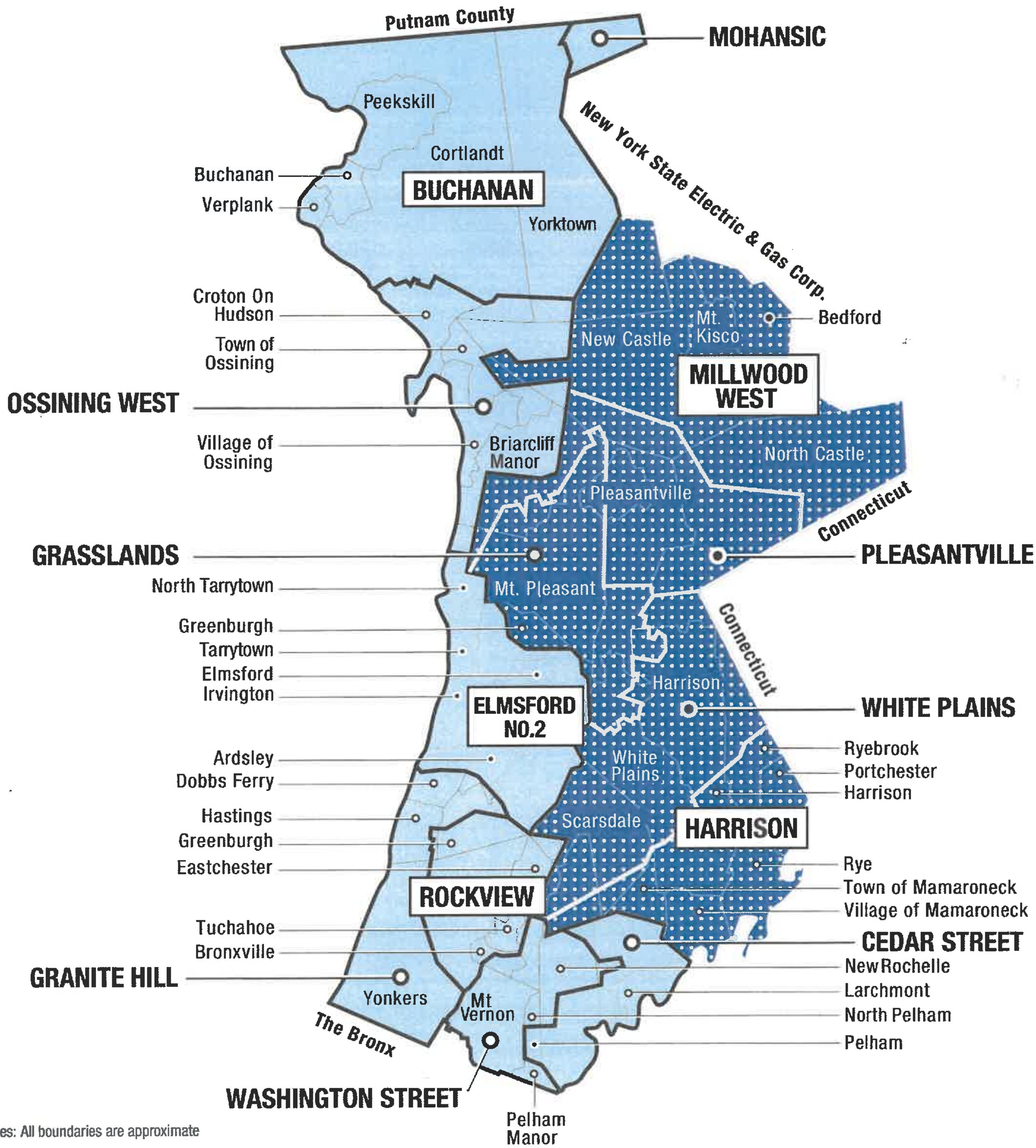
	11 a.m. - 3 p.m.	(11:00 - 15:00)
	2 p.m. - 6 p.m.	(14:00 - 18:00)
	4 p.m. - 8 p.m.	(16:00 - 20:00)
	7 p.m. - 11 p.m.	(19:00 - 23:00)



Notes: All boundaries are approximate

Westchester Map

■	11 a.m. - 3 p.m.	(11:00 - 15:00)
■ (dotted)	2 p.m. - 6 p.m.	(14:00 - 18:00)
□	4 p.m. - 8 p.m.	(16:00 - 20:00)
□ (dotted)	7 p.m. - 11p.m.	(19:00 - 23:00)



Notes: All boundaries are approximate

Con Edison Demand Response Programs

Distribution Load Relief Program (2 Hour or Less Notification Program)

List of Tier 2 Networks for 2024

Customers participating in DLRP will be asked to reduce their energy use when there is a contingency affecting their specific area of Con Edison's electric system. Notice will be provided two hours or less before the demand response event start time. Electrical networks are separated into two tiers - Tier 1 and 2. Tier 2 networks are considered a higher priority for demand response and are paid at a higher incentive rate than the accounts in Tier 1 networks.

Any network not listed as Tier 2 is categorized as Tier 1.

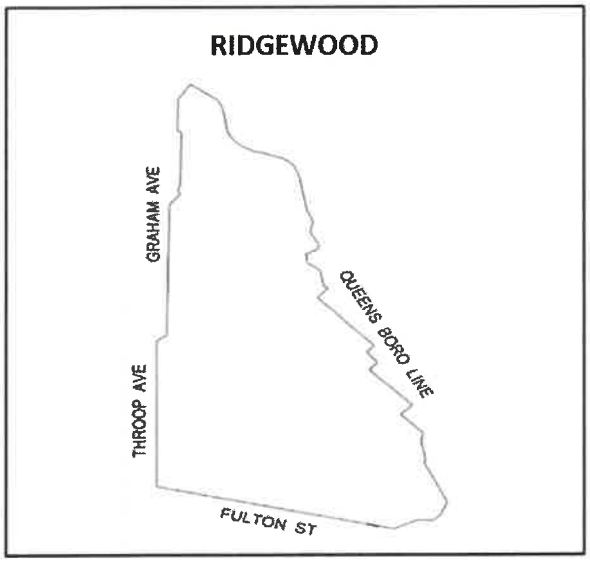
For the 2024 DR season, two new networks will be categorized as a Tier 2 networks (Jamaica and Riverdale). Two networks will revert back to Tier 1 classification (Ocean Parkway and Borough Hall). These changes were made in accordance with the revised evaluation criteria, as ordered by the PSC as part of filing 17-E-0741, to align the Tier 2 networks with those in most need of contingency load relief.

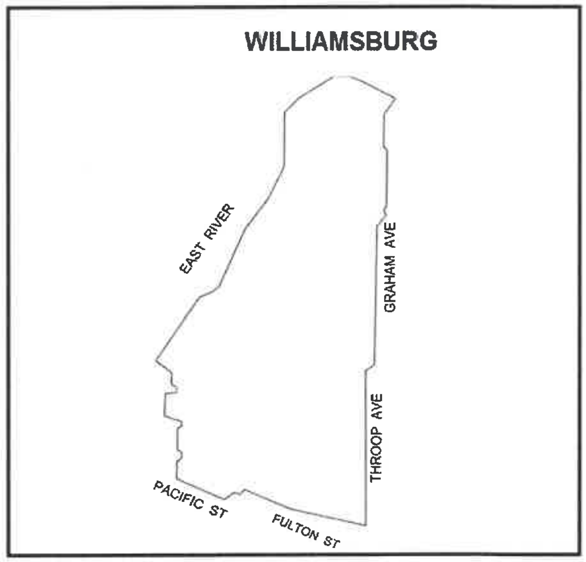
Network boundaries are typically different from neighborhood borders. For example, the Richmond Hill network includes parts of Brooklyn and Queens. Current Aggregators and Direct Enroll customers should use the Network Lookup tool in the DR/SUR Portal to confirm the assigned network and DLRP tier. If you have further questions, email Con Edison's Demand Response team at demandresponse@coned.com

2024 DLRP Tier 2 Networks
Central Bronx
Fordham
Jackson Heights
Jamaica
Northeast Bronx
Ridgewood
Riverdale
Southeast Bronx
West Bronx
Williamsburg

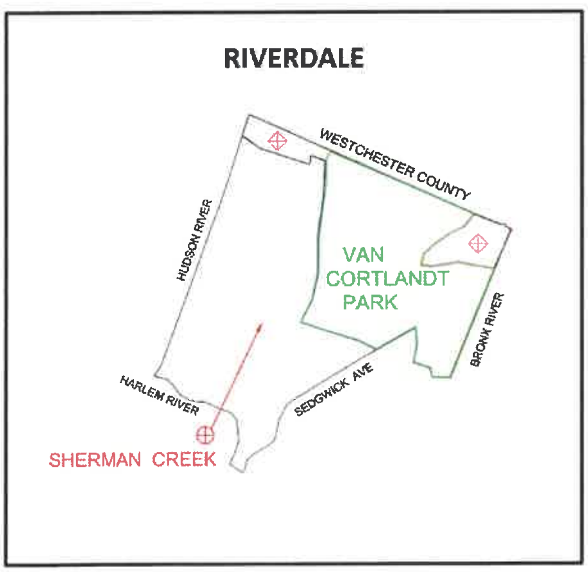
Distribution Load Relief Program (2 Hour or Less Notification Program)
Maps of Tier 2 Networks for 2024

Brooklyn Networks



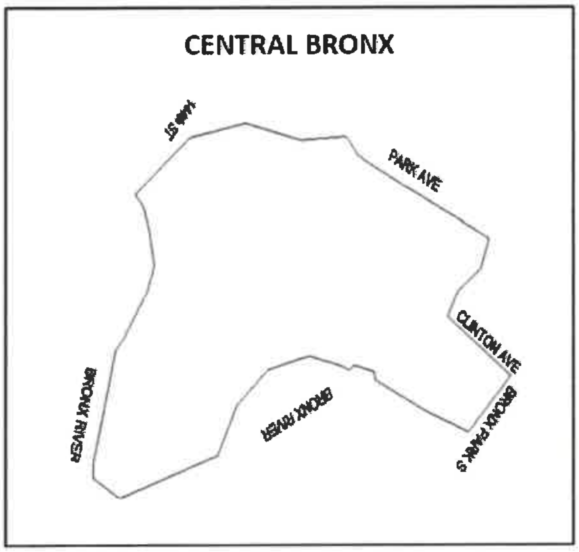


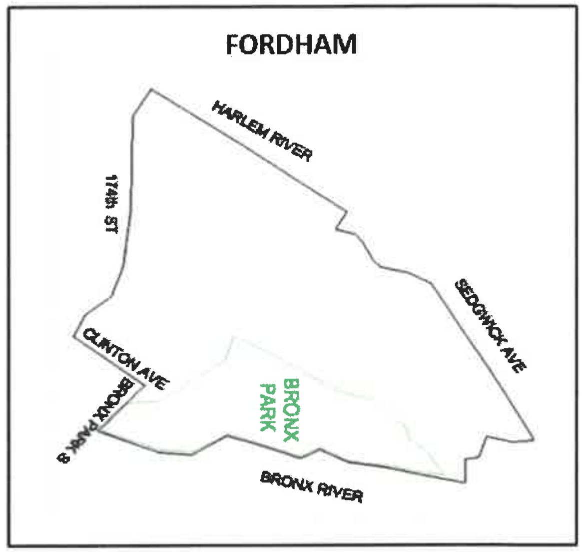
Westchester Network

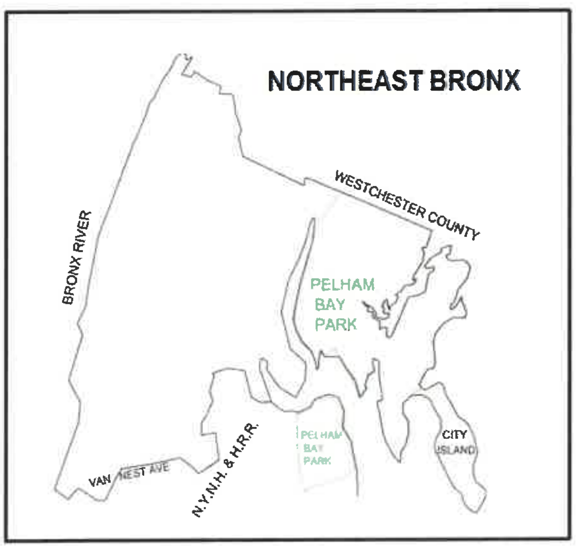


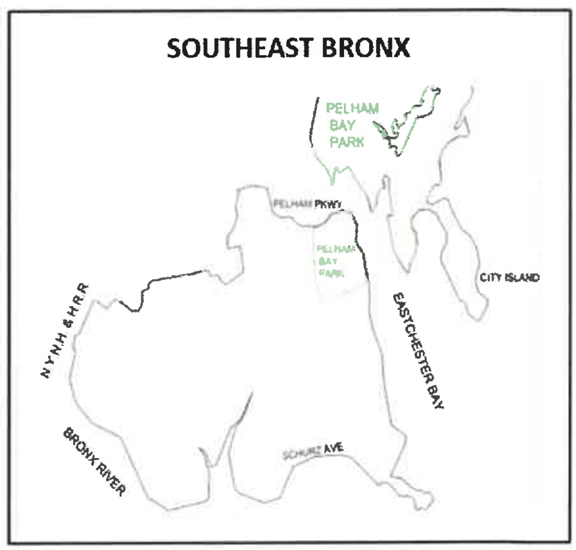
Distribution Load Relief Program (2 Hour or Less Notification Program)
Maps of Tier 2 Networks for 2024

Bronx Networks









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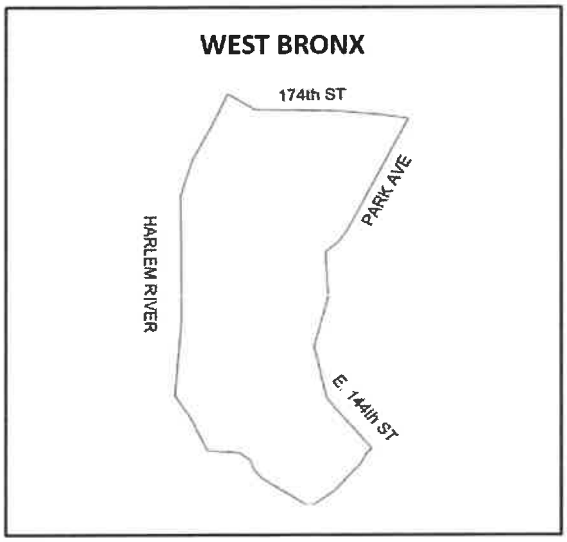
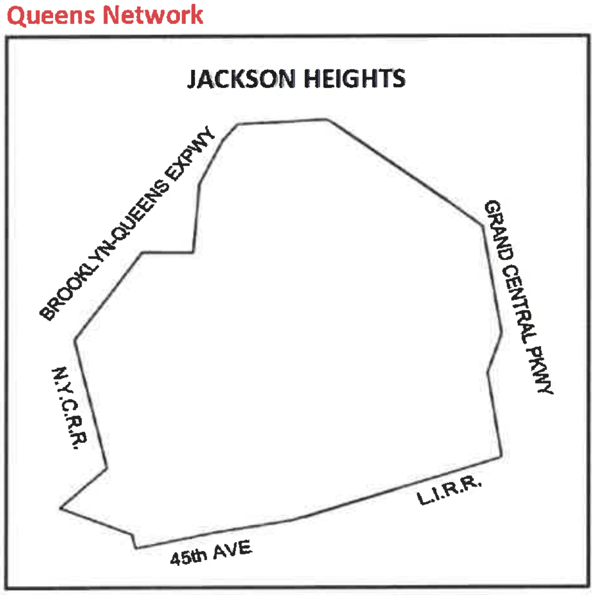
Distribution Load Relief Program (2 Hour or Less Notification Program)
Maps of Tier 2 Networks for 2024

Bronx Networks (continued)



Queens Network



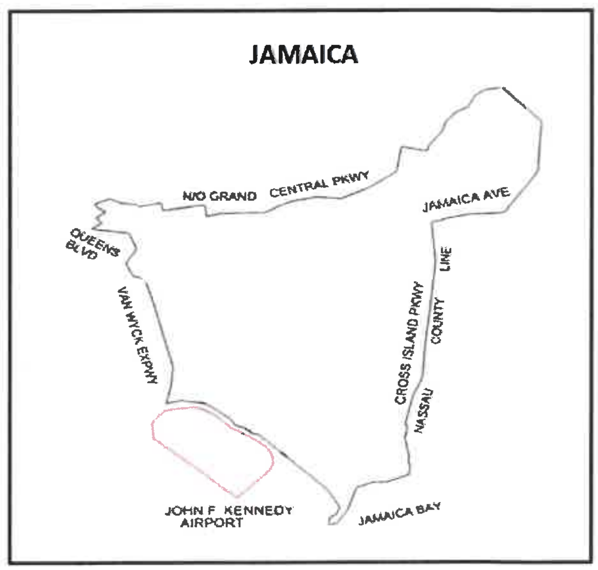


Exhibit 9

conEdison	Coordinated Electric System Interconnect Review	Doc # MC-695954
	Distributed Energy Resources - NYSSIR	Date: December 7, 2023

For

Interconnection Customer: Inc., New Leaf Energy

Applicant: Bain, Christian

Company: New Leaf Energy, Inc.

5,000 kW Battery Energy Storage Generator System

333 N BEDFORD RD
Mount Kisco , NY 10549

Interconnection to Consolidated Edison Company of New York

Westchester Region

Millwood West Network

Millwood West Substation

13 kV Feeder 7W46 - Mount Kisco Autoloop

TABLE OF CONTENTS

1.0 INTRODUCTION

This report presents the analysis results of the Consolidated Edison Company of New York ("Consolidated Edison" or the "Company") interconnection study based on the proposed interconnection and design submittal from the Interconnection Customer in accordance with the Company Engineering Standard EO-2115. The intent of this report is to assess this project's feasibility, determine its impact to the existing electric power system (EPS), determine interconnection scope and installation requirements, and determine costs associated with interconnecting the Interconnection Customer's generation to the Company's Electric Power System (EPS). This Coordinated Electric System Impact Review (CESIR) study; according to the New York State Standardized Interconnection Requirements (NYSSIR) Section I.C Step 6; identifies the scope, schedule, and costs specific to this Interconnection Customer's installation requirements.

2.0 EXECUTIVE SUMMARY

The interconnection was found to be feasible with modifications to the existing Company EPS and operating conditions, which are described in detail in the body of this Study.

The total estimated planning grade cost of the work associated with the interconnection of the Interconnection Customer is as follows:

- Install New Service and Monitoring and Control - $136,172.43

If utility system or service upgrades are required, the applicant has 90 business days to pay at least 25% of the costs and 120 business days to provide full payment. Upon full payment the utility will commence construction of system modifications. If the Interconnection Solutions above are not amenable to you, you may choose to withdraw your application, in which case your interconnection request will not move forward and no further action on the part of the utility is required. In order to move forward, please log into the Power Clerk Portal within 10 business days to choose the Interconnection Solution that best fits your needs. By selecting an Interconnection Solution presented above, the applicant is committing to the utility upgrades described as well as the project design or document revisions described below.

3.0 COMPANY EPS PARAMETERS

Substation	**Millwood West**
Transformer Name (list multiple where normally tied to common bus)	TR1; TR2
Transformer Peak Load (kW)	67,524.7
Contingency Condition Load, N-1 Criteria (kW) (as applicable)	NA
[Daytime, 24 hour] Light Load (kW)	20,257.41
Generation: Total (kW)	46,287.03
Generation: Connected (kW)	9,518.77
Generation: Queued Ahead (kW)	36,768.26
Contingency Condition Generation: Total (kW)	0
Contingency Condition Generation: Connected (kW)	0
Contingency Condition Generation: Queued Ahead (kW)	0
Supply Voltage (kV)	13.41
Transformer Maximum Nameplate Rating (kVA)	130,600
Distribution Bus Voltage Regulation	Yes
Transmission GFOV Status	Installed
Bus Tie	Closed
Number of Feeders Served from this Bus	11

Connecting Feeder/Line	**7W46 / Mount Kisco - 2**
Peak Load on feeder (kW)	8,338
[Daytime, 24 hour] Light Load on Feeder (kW)	2,501
Feeder Primary Voltage at POI (kV)	13.38
Line Phasing at POI	3
Circuit distance from POI to substation	NA
Distance (miles) from POI to nearest 3-phase, (if applicable)	NA
Line Regulation	Yes
Line/Source Grounding Configuration at POI	Effective
Other Generation: Total (kW)	10,791.9
Other Generation: Connected (kW)	532.34
Other Generation: Queued Ahead (kW)	10,259.56
System Fault Characteristics without Interconnection Customer DG at POI with System Upgrades described in Section 6	
Interconnection Customer POI Location	MTC46:104CF_40B
I 3-phase (3LLL)	5484.8
I Line to Ground (3I0)	3179.7
Z1 (100 MVA base)	0.785
Z0 (100 MVA base)	2.498

4.0 INTERCONNECTION CUSTOMER SITE

The Interconnection Customer is proposing a new service connection.

The proposed DG system at 333 N BEDFORD ROAD, MOUNT KISCO, NY 10549 consists of a 5,000 kW (22,000 kWh) system consisting of six (6) Tesla Megapack 2XL – four (4) P080 - 800 kVA & EC20 - 816 kW and two (2) P090 - 900 kVA & EC23 - 938.4 kW.

To allow for this ESS system, the system will be connected to the Mount Kisco Loop – 7W46. Con Ed will install a new 50ft Class 1 Pole about 30ft north of Pole T40B and 30ft south of Pole 41. They will install solid blades on the new pole in line with customer pole. Next, they will install 3-1/0 AL openwire primary (fed from FDR 7W46, Mount Kisco Loop) and a 1-1/0 AL secondary neutral from the new pole to customer pole. Finally, they will furnish and deliver a 16KA STS Switch which is to be placed on the customer pole. This design will follow EO-10215.

This service ruling was used as the basis of this study. If the ruling changes, the results of this study will no longer be valid.

5.0 SYSTEM IMPACT ANALYSIS

Additional Comments:

The proposed DG system at 333 N BEDFORD ROAD, MOUNT KISCO, NY 10549 consists of a 5,000 kW (22,000 kWh) system consisting of six (6) Tesla Megapack 2XL – four (4) P080 - 800 kVA & EC20 - 816 kW and two (2) P090 - 900 kVA & EC23 - 938.4 kW. We have completed an analysis of the proposed DER system and reviewed the documents provided. Our study results indicate that the need for SCADA equipment is required.

Category	Criteria	Limit	Description	Result
Voltage	Overvoltage	< 105% (ANSI C84.1 and EO2065)	With the addition of the subject generator the maximum voltage as modeled on the POI is 104% of nominal.	Pass
Voltage	Undervoltage	> 95% (ANSI C84.1 and EO2065)	With the addition of the subject generator the minimum voltage as modeled on the POI is 100% of nominal.	Pass
Voltage	Substation Regulation for Reverse Power	<NA% minimum load criteria	The total generation on FeedersNA is NA MW. The total minimum load on these Feeders is NA MW. Therefore, the generation to load ratio is NA%.	NA
Voltage	Feeder Regulation for Reverse Power	<NA% Minimum load to generation ratio	The total generation downstream of voltage regulator NA is NA MW. The minimum load downstream of the voltage regulator is NA MW. Therefore, the generation to load ratio is NA%.	NA
Voltage	Fluctuation	<3% steady state from proposed generation on feeder		Pass
Voltage	Fluctuation	<5% steady state from aggregate DER on substation bus		Pass
Voltage	Fluctuation	Regulator tap movement exceeds 1 position, generation change of 75% of nameplate rating does not result in voltage change > ½ the bandwidth of any feeder voltage regulating device.	The greatest voltage fluctuation on the feeder occurs at NA and substation bus occurs at NA. The resulting fluctuation at the feeder location is NA% due to the proposed generation and NA% on the substation bus due to the aggregate generation. Additional details for voltage regulators : NA	NA
Voltage	Flicker	Screen H Flicker	The Pst for the location with the greatest voltage fluctuation is 0.059 and the emissions limit is 0.35.	Pass
Equipment Ratings	Thermal (continuous current)	<NA% thermal limits assuming no load	The subject generator's full output current is NA A. The total full output current of all DER downstream of NA is NA A. NA thermal capabilities are NA A.	NA
Equipment Ratings	Withstand (fault current)	<90% withstand limits	The additional fault current contribution from the generation contributes to interrupting ratings in excess of existing EPS equipment.	Pass
Protection	Unintentional Islanding	Unintentional Islanding Document & Company Guidelines		Pass
Protection	Protective device coordination	Company Guidelines		Pass
Protection	Fault Sensitivity	Rated capabilities of EPS equipment		Pass
Protection	Ground Fault Detection	Reduction of reach > x% (by Utility)	The Interconnection Customer has proposed a grounding bank with an impedance of NA ohms and X/R ratio of NA. To be within Company guidelines the grounding bank shall have an impedance of NA ohms. The Interconnection Customer will contribute approximately NA A of 3I0 current to remote bolted line to ground faults and NA A to faults at the PCC.	NA
Protection	Overvoltage Transmission System Fault	Company 3V0 criteria	The generation to load ratio on the serving distribution system has failed the Company's planning threshold in which transmission ground fault overvoltage become an electrical hazard due to the distribution source contribution. An evaluation of the existing EPS has been performed and it has been determined that protection mitigation methods are required.	Pass
Protection	Overvoltage Distribution System Fault	<NA% voltage rise	With subject generator interconnected the modeled voltage rise on the unfaulted phases of the system is NA%.	NA
Protection	Effective Grounding	NA	With subject generator interconnected the modeled R0/X1 is 1.77 PU and the X0/X1 is 3.04 PU.	Pass
SCADA	Required EMS Visibility for Generation Sources	Monitoring & Control Requirements	The 5 MW subject generator triggers the requirement for SCADA reporting to the Utility.	Yes

Other				NA

Project Design/Document Revision Comments:

3-Line: The DER would be interconnected under Con Ed spec EO-10215. Make sure that the HTME, property Line box and feeder ducts are compliant with EO-10215. The HTME should comply with EO-10215 and MES-350. Please put the total size of the system on the drawing. Please insure the settings are set to the IEEE1547. The inverters shall be set for these settings. Please highlight that the 89L switch is an external, manual, visible, gangoperated, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the customer-generator, and located between the generating equipment and its interconnection point with the utility system. Customer is required to submit supporting documentation to confirm that Generator Disconnect Switch has the provision to be locked in open position. The high-tension switchgear needs to be electrically operated with a manual control circuit that does not require an operator to stand directly in front of the switchgear's cubicle. • The inverters shall be set for the following settings. Mention these settings on the line diagram. IEEE1547 Protective Settings OV1 – 1.1 pu / 2.0 sec OV2 – 1.2 pu / 0.16 sec UV1 – 0.8 pu / 3.0 sec UV2 – 0.5 pu / 1.1 sec OF1 – 61.2 Hz / 300 sec OF2 – 62.0 Hz / 0.16 sec UF1 – 58.5 Hz / 300 sec UF2 – 56.5 Hz / 0.16 sec Site plan: please put the total size of the system on the diagram along with the inverter size/ type/ location information.

Inverter Verification Testing Procedure

- Please make this site specific and ESS specific.
- Include IEEE1547 inverter relay and Volt-VAR setpoints as part of the commissioning test
- Include space to record the results of the inverter test for each inverter
- The testing procedure must include instructions for how to test the IEEE1547 settings, how to perform a test simulating utility shutdown, and how toperform a test simulating utility restoration. Inverters must shut down within 2 seconds of loss of utility power. A five-minute waiting period must elapse between the restoration of utility power and renewed operation of inverters.

6.0 MITIGATIONS FOR SYSTEM IMPACT ANALYSIS FAILURES

Detail below is intended to provide sufficient information and clarity to give the Interconnection Customer an understanding to the relationship of costs and scope associated with the DER interconnection and the system modifications due to the DER impact. This includes any required EPS equipment upgrades. Where scope items are identified, associated labor, equipment rentals and indirect project support functions (such as engineering and project management) are intended and implied.

Sl.No	Option	Description	Capacity	Cost
1	Install New Service and Monitoring and Control	100% OPTION – Full Battery Capacity	DER1 : 5,000 kW	$136,172.43

Additional details on the scope of each option can be found below:

Interconnection Solution #1:	Install New Service and Monitoring and Control

The proposed DG system at 333 N BEDFORD ROAD, MOUNT KISCO, NY 10549 consists of a 5,000 kW (22,000 kWh) system consisting of six (6) Tesla Megapack 2XL – four (4) P080 - 800 kVA & EC20 - 816 kW and two (2) P090 - 900 kVA & EC23 - 938.4 kW.

The max charge rate is the requested 2,200 kW during the window 10:00PM – 8:00AM. The max export rate is 5,000 kW from 12:00PM to 8:00PM.

The system will be connected to the Mount Kisco Loop – 7W46. Con Ed will install a new 50ft Class 1 Pole about 30ft north of Pole T40B and 30ft south of Pole 41. They will install solid blades on the new pole in line with customer pole. Next, they will install 3-1/0 AL openwire primary (fed from FDR 7W46, Mount Kisco Loop) and a 1-1/0 AL secondary neutral from the new pole to customer pole. Finally, they will furnish and deliver a 16KA STS Switch which is to be placed on the customer pole. This design will follow EO-10215.

Relay Settings: The settings are intended to conform to IEEE 1547-2018 and 1547a-2020. For inverter-based systems, the default settings shall be input on UL 1741 SB certified smart inverters interconnecting to the Con Edison Electric System.

SCADA Monitoring and Control is required due to the size of the project and the potential impact on the system. The purpose of the SCADA is to monitor customer power production and issue customer control commands when needed.

The SCADA Scope of work will include:
· Monitor 1 x OH Switch, 32R/F Setting, provide 1 x modem
· Purchase and assembly of 1 x ventilated Enclosure
· ESS Monitoring
· ESS Controls
· Testing and Commissioning

Volt Var shall be enabled on the inverters with coned standard settings and the DER should have capability to switch into constant reactive power mode temporarily using remote control and provide 2.5MVAR of reactive power support to the grid. This would help in reducing the impact of the charging cycle on the feeder loading and maintain adequate future hosting capacity of the supplying 13 kV feeders.

The Customer's generation system needs to accept a normally closed dry contact that will signal normal operation when the contact is closed. When the contact opens, the customer's generation must reduce its power production immediately (no intentional delay) by disconnecting at least a portion of generators such that their system is no longer in violation of the prescribed operating characteristics. This contact opening will be wired by the customer to behave as a hardwired direct trip of inverters without any additional processing by non-inverter programmable controllers. The customer must provide their own wetting voltage through that dry contact (up to 30 VDC or up to 120VAC, 5 Amps Ratings). The normally-closed dry contact exists inside of the Con Edison RTU enclosure. The customer needs to run a pair of wires to this contact. This contact opening should only result in inverters disconnecting from the grid source. No AUX loads need to be disconnected. It is also acceptable to have electrically operated circuit breakers wired to trip when the RTU contact opens, instead of wiring the contact to inverters directly, as long as the resulting immediate power reduction is achieved. After inverter disconnection, the RTU will recognize the power reduction. The dry contact will reclose after violations of operating characteristics have been mitigated and/or system conditions have returned to normal. Circuit breakers may reclose (auto or manual means, remote or local control) and inverters may restart and resume grid-connected operation. The customer's site controller shall realize the cause of the direct trip and operate in a manner that reconnects a level of generation that is no longer in violation of the prescribed operating characteristics. In addition to the above described direct trip contact, the Con Edison RTU is also sending a binary output DNP3 register (e.g. trip signal, transfer trip) to the customer's site controller. This signal will tell the customer's system to cease or curtail operation when binary "1" has been received. The expected reaction shall be the same as what is expected with the hardwired direct trip. The binary signal will revert back to "0" after violations of operating characteristics have been mitigated and/or system conditions have returned to normal. The method of data communication between the Con Ed RTU shall be DNP3 protocol using serial communication, RS-485, 38.4k baud, 8 data bits, 1 stop bit, 2-wire, twisted shielded pair with the shield grounded at the Con Ed RTU. The customer must supply this serial comm. cable between the Con Ed RTU and the site controller's serial data communication port or suitable converter.

Distribution Engineering Cost Estimate - System Upgrades Cost

Activity	Material Cost	Labor Cost	Sub Total
SCADA/ Anti-Islanding (E.g.Construction, Installation, Programming, Testing, Etc.)	$5,968.00	$23,671.60	$29,639.60
Sub Total	$5,968.00	$23,671.60	$29,639.60

Sub Total (Material & Labor Cost)	Overhead Cost	Contingency Cost	Total Cost
$29,639.60	$3,338.39	$4,946.70	$37,924.69

Customer Engineering Cost Estimate - Service Cost

Activity	Labor	Material	Stores & Handling	Transportation	Outside Contract Work	Corporate Overhead	Contingency	Sub Total
INSTALL REPLACE OH PRI COND OPEN WIRE SPAN	$16,966.95	$42,284.00	$3,594.14	$1,696.70	$0.00	$11,617.53	$9,681.27	$85,840.59
INSTALL REPLACE OH POLES TOWERS FIXTURES	$7,712.25	$779.00	$66.22	$771.22	$0.00	$1,679.16	$1,399.30	$12,407.15
						Total Cost	$98,247.74	

Per the SIR's Cost Sharing 2.0 Process, this project does not qualify as a Triggering or Sharing Project based upon the estimated qualifying upgrades contained within the CESIR. Qualifying Upgrades Total: $0.00 .

The substation upgrades required to facilitate the proposed installation include the following:
None

The Distribution upgrades required to facilitate the proposed installation include the following:
See above

The ability to generate is contingent on this facility being served by the interconnecting circuit during normal Utility operating conditions. Therefore, if the interconnecting circuit is out of service, or if abnormal utility operating conditions of the area EPS are in effect, the Company reserves the right to disengage the facility.

Any change in system size and/or design is subject to the requirements of the NYSSIR, as well as supplemental documents developed by the Interconnection Technical Working Group and Interconnection Policy Working Group.

7.0 CONCEPTUAL COST ESTIMATE

The following items are a good faith estimate for the scope and work required to interconnect the project estimated under rates and schedules in effect at the time of this study in accordance with the most recent version of the NYSSIR.

Planning Grade

Estimate See cost estimates in Section 6 Notes:

- These estimated costs are based upon the results of this study and are subject to change. All costs anticipated to be incurred by the Company are listed.
- The Company will reconcile actual charges upon project completion and the Interconnection Customer will be responsible for all final charges, which may be higher or lower than estimated according to the NYSSIR I.C step 11.
- Upon receipt of additional payments by Sharing Projects the utility shall reconcile with the Triggering Project based on a calculated estimated prorata share. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
- This estimate does not include the following:
    1. additional interconnection study costs, or study rework
    2. additional application fees,
    3. applicable surcharges,
    4. property taxes,
    5. sales tax,
    6. future operation and maintenance costs,
    7. adverse field conditions such as weather and Interconnection Customer equipment obstructions,
    8. extended construction hours to minimize outage time or Company's public duty to serve, 9. the cost of any temporary construction service, or
    10. any required permits.
- Cost adders estimated for overtime would be based on 1.5 and 2 times labor rates if required for work beyond normal business hours. Per Diems are also extra costs potentially incurred for overtime labor.

8.0 GENERAL REQUIREMENTS FOR ALL DG INTERCONNECTIONS

A. Provide the load dispatcher name and phone number you wish to appear in the First Amendment (document to follow). Note that this contact is required to be available at this phone number 24 hours, 7 days a week. The contact will need to be available for communications regarding emergency operation of customer equipment and may need to provide access to their equipment if necessary.

B. The generator disconnect switch (intertie disconnect) shall provide a visible break, manual, gang-operated, loadbreak, lockable, and accessible isolating device.

C. At the location, and on the drawing, identify and clearly label the "GENERATOR DISCONNECT SWITCH 89L" with permanent 3/8 inch letters or larger.

D. The labeling of the "AC Panel" housing the inverter circuit breakers should have additional label that reads; "DEVICE 52IT PANEL" and the individual breakers labeled as 52IT-1, 52IT-2, et cetera, to correspond with the associated inverter (i.e. Inverter 1, Inverter 2…etc.).

E. Labeling of all inverters, junction boxes, combiner boxes, array strings, and fuses at the site is required and shall be consistent as to assist with identifying the circuit runs.

F. Field installation and one/three-line diagram should match 100%. All equipment concerning the DG installation at this site should be shown on this diagram. This includes the incoming service (with cable size and type), end-line-box, the main distribution panel (with all load takeoffs), and the existing electric meter.

G. Any revisions to the one/three-line diagram should include an updated revision number, date, and comments on the diagram that briefly indicate the changes made.

H. Per the NYS SIR, Section II.I., the verification testing procedure will need to be accurate enough to repeat without confusion in upcoming years for periodic performance retesting.

I. All documentation and proper drawings should be submitted and approved prior to the testing and commencement of operation of your equipment.
This includes certified relay test reports where applicable.

J. Copies of the three-line circuit diagram shall be laminated and displayed on site within close vicinity of the Con Edison revenue meter and any other generator disconnects downstream. Signage at the revenue meter should include that the meter is fed from two sources. Additional signage shall also be included as to the location of the disconnect switch.

K. Please note if the project site has multiple DERs installed or scheduled to be installed, your request to be interconnected under SIR governance must meet the requirements of the ORDER MODIFYING SEPARATE SITE REQUIREMENTS (Issued and Effective April 15, 2021). Utility construction shall not commence until the project adheres to the requirements of the Order. All SIR guidelines and timers shall remain in effect in parallel with this requirement.

Exhibit 10

APPENDIX A -

NEW YORK STATE STANDARDIZED CONTRACT FOR INTERCONNECTION OF NEW DISTRIBUTED GENERATION UNITS AND/OR ENERGY STORAGE SYSTEMS WITH CAPACITY OF 5 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS

Interconnection Customer Information:

Name:
North Bedford Energy Storage 1, LLC

Address:
333 North Bedford Road
Mt Kisko, NY 10549

Telephone:
(800) 818-5249

Fax:

Email:
intx-ny@newleafenergy.com

Unit Application/File No.:
LDG-04302

Utility Information:

Name:
Consolidated Edison Company of NY, Inc.

Address:
4 Irving Pl., New York, NY 10003

Telephone:
1-800-752-6633 (1-800-75-CONED)

Fax:

Email:
dgexpert@coned.com

Utility Account Number:
99999999999999

DEFINITIONS

Delivery Service means the services the Utility may provide to deliver capacity or energy generated by the Interconnection Customer to a buyer to a delivery point(s), including related ancillary services.

Energy Storage System (ESS) means a commercially available mechanical, electrical, or electro-chemical means to store and release electrical energy, and its associated electrical inversion device and control functions that may be stand-alone or paired with a distributed generator at a point of common coupling.

Interconnection Customer means the owner of the Unit.

Interconnection Facilities means the equipment and facilities on the Utility's system necessary to permit operation of the Unit in parallel with the Utility's system.

Material Modification means a Modification to a Unit that may have adverse impacts on the Utility's system, Utility customers, other projects, or applications in the interconnection queue.

Modification means a change to the ownership, equipment, equipment ratings, equipment configuration, or operating conditions of the Unit.

Premises means the real property where the Unit is located.

SIR means the New York State Standardized Interconnection Requirements for new distributed generation units and/or energy storage systems with a nameplate capacity of 5 MW or less connected in parallel with the Utility's distribution system.

Unit means the distributed generation, stand-alone ESS, or combined generation and ESS facilities approved by the Utility for operation in parallel with the Utility's system. This Agreement relates only to such Unit, but a new agreement shall not be required if the Interconnection Customer makes physical alterations to the Unit that do not result in an increase in its nameplate generating capacity. The nameplate generating capacity or inverter/converter rating of the Unit shall not exceed 5 MW.

Utility means Consolidated Edison of New York, Inc. (Con Edison).

I. TERM AND TERMINATION

1.1 Term: This Agreement shall become effective when executed by both Parties and shall continue in effect until terminated.

1.2 Termination: This Agreement may be terminated as follows:

a. The Interconnection Customer may terminate this Agreement at any time, by giving the Utility sixty (60) days' written notice.

b. Failure by the Interconnection Customer to seek final acceptance by the Utility within twelve (12) months after completion of the utility construction process described in the SIR shall automatically terminate this Agreement.

c. Either Party may, by giving the other Party at least sixty (60) days' prior written notice, terminate this Agreement in the event that the other Party is in default of any of the material terms and conditions of this Agreement. The terminating Party shall specify in the notice the basis for the termination and shall provide a reasonable opportunity to cure the default.

d. The Utility may, by giving the Interconnection Customer at least sixty (60) days' prior written notice, terminate this Agreement for cause. The Interconnection Customer's non-compliance with an upgrade to the SIR, unless the Interconnection Customer's installation is "grandfathered," shall constitute good cause.

1.3 Disconnection and Survival of Obligations: Upon termination of this Agreement the Unit will be disconnected from the Utility's electric system. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

1.4 Suspension: This Agreement will be suspended during any period in which the Interconnection Customer is not eligible for Delivery Service from the Utility

II. SCOPE OF AGREEMENT

2.1 Scope of Agreement: This Agreement relates solely to the conditions under which the Utility and the Interconnection Customer agree that the Unit may be interconnected to and operated in parallel with the Utility's system.

2.2 Electricity Not Covered: The Utility shall have no duty under this Agreement to account for, pay for, deliver, or return in kind any electricity produced by the Facility and delivered into the Utility's System unless the system is net metered as described in Public Service Law Section 66-l.

III. INSTALLATION, OPERATION AND MAINTENANCE OF UNIT

3.1 Compliance with SIR: Subject to the provisions of this Agreement, the Utility shall be required to interconnect the Unit to the Utility's system, for purposes of parallel operation, if the Utility accepts the Unit as in compliance with the SIR. The Interconnection Customer shall have a continuing obligation to maintain and operate the Unit in compliance with the SIR.

3.2 Observation of the Unit - Construction Phase: The Utility may, in its discretion and upon reasonable notice, perform reasonable on-site verifications during the construction of the Unit. Whenever the Utility chooses to exercise its right to perform observations herein it shall specify to the Interconnection Customer its reasons for its decision to perform the observation. For purposes of this paragraph and paragraphs 3.3 through 3.5, the term "on-site verification" shall not include testing of the Unit, and verification tests shall not be required except as provided in paragraphs 3.3 and 3.4.

3.3 Observation of the Unit - Ten-day Period: The Utility may perform on-site verifications of the Unit and observe the execution of verification testing within a reasonable period of time, not exceeding ten (10) business days after system installation. The Unit will be allowed to commence parallel operation upon satisfactory completion of the verification test.The Interconnection Customer must have complied with and must continue to comply with all contractual and technical requirements.

3.4 Observation of the Unit - Post-Ten-day Period: If the Utility does not perform an

on-site verification of the Unit and observe the execution of verification testing within the ten-day period, the Interconnection Customer will send the Utility within five (5) days of the verification testing a written notification certifying that the Unit has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The Interconnection Customer may begin to produce energy upon satisfactory completion of the verification test. After receiving the verification test notification, the Utility will either issue to the Interconnection Customer a formal letter of acceptance for interconnection, or may request that the applicant and utility set a date and time to perform an on-site verification of the Unit and make reasonable inquiries of the Interconnection Customer, but only for purposes of determining whether the verification tests were properly performed. The Interconnection Customer shall not be required to perform the verification tests a second time, unless irregularities appear in the verification test report or there are other objective indications that the tests were not properly performed in the first instance.

3.5 Observation of the Unit - Operations: The Utility may perform on-site verification of the operations of the Unit after it commences operations if the Utility has a reasonable basis for doing so based on its responsibility to provide continuous and reliable utility service or as authorized by the provisions of the Utility's Retail Electric Tariff relating to the verification of

Interconnection Customer installations generally.

3.6 Costs of Interconnection Facilities: During the term of this Agreement, the Utility shall design, construct and install the Interconnection Facilities. The Interconnection Customer shall be responsible for paying the incremental capital cost of such Interconnection Facilities attributable to the Interconnection Customer's Unit. All costs associated with the operation and maintenance of the Dedicated Facilities after the Unit first produces energy shall be the responsibility of the Utility.

3.7 Modifications to the Unit: The Interconnection Customer may request a Modification at any time after commencement of parallel operation. The Utility shall evaluate the request and determine whether the proposed change is a Material Modification in accordance with the rules for requesting changes to applications in the SIR. A Material Modification will be studied pursuant to the procedures in the SIR for new applications. In the case of a non-material modification that is accepted by the Utility, the parties will execute an amendment to this Agreement describing the Unit changes that have been approved.

IV. DISCONNECTION OF THE UNIT

4.1 Emergency Disconnection: The Utility may disconnect the Unit, without prior notice to the Interconnection Customer (a) to eliminate conditions that constitute a potential hazard to Utility personnel or the general public; (b) if pre-emergency or emergency conditions exist on the Utility system; (c) if a hazardous condition relating to the Unit is observed by a Utility inspection; or (d) if the Interconnection Customer has tampered with any protective device. The Utility shall notify the Interconnection Customer of the emergency if circumstances permit. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an emergency condition that affects the Unit that may reasonably be expected to affect the Utility EPS.

4.2 Non-Emergency Disconnection Due to Unit Performance: The Utility may disconnect the Unit, after notice to the responsible party has been provided and a reasonable time to correct, consistent with the conditions, has elapsed, if (a) the Interconnection Customer has failed to make available records of verification tests and maintenance of his protective devices; (b) the Unit system interferes with Utility equipment or equipment belonging to other customers of the Utility; (c) the Unit adversely affects the quality of service of adjoining customers; (d) the ESS does not operate in compliance with the operating parameters and limits described in Attachment 1 to this Agreement.

4.3 Non-Emergency Disconnection for Utility Work: The Utility may disconnect the Unit after notice to Interconnection Customer when necessary for routine maintenance, construction, and repairs on the Utility EPS. The Interconnection Customer may request to reconnect its service prior to the completion of the Utility's work. The Utility shall accommodate such requests, provided that the Interconnection Customer shall be responsible for the costs of the Utility's review and any system modifications required to reconnect the Unit ahead of schedule.

4.4 Disconnection by Interconnection Customer: The Interconnection Customer may disconnect a Unit with an AC nameplate rating above 300 kW upon 18 hours advance notice to the Utility if the planned shutdown will last 8 hours or more. For non-emergency forced outages lasting 8 hours or more, the Interconnection Customer shall notify the Utility within 24 hours of the commencement of the shutdown.

4.5 Utility Obligation to Cure Adverse Effect: If, after the Interconnection Customer meets all interconnection requirements, the operations of the Utility are adversely affecting the performance of the Unit or the Customer's premises, the Utility shall immediately take appropriate action to eliminate the adverse effect. If the Utility determines that it needs to upgrade or reconfigure its system, the Interconnection Customer will not be responsible for the cost of new or additional equipment beyond the point of common coupling between the Interconnection Customer and the Utility.

V. ACCESS

5.1 Access to Premises: The Utility shall have access to the disconnect switch of the Unit at all times. At reasonable hours and upon reasonable notice consistent with Section III of this Agreement, or at any time without notice in the event of an emergency (as defined in paragraph 4.1), the Utility shall have access to the Premises.

5.2 Utility and Interconnection Customer Representatives: The Utility shall designate, and shall provide to the Interconnection Customer, the name and telephone number of a representative or representatives who can be reached at all times to allow the Interconnection Customer to report an emergency and obtain the assistance of the Utility. For the purpose of allowing access to the premises, the Interconnection Customer shall provide the Utility with the name and telephone number of a person who is responsible for providing access to the Premises.

5.3 Utility Right to Access Utility-Owned Facilities and Equipment: If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Utility access to the Utility's equipment and facilities located on the Premises. To the extent that the Interconnection Customer does not own all or any part of the property on which the Utility is required to locate its equipment or facilities to serve the Interconnection Customer under this Agreement, the Interconnection Customer shall secure and provide in favor of the Utility the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

VI. DISPUTE RESOLUTION

6.1 Good Faith Resolution of Disputes: Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

6.2 Mediation: If a dispute arises under this Agreement, and if it cannot be resolved by the Parties within ten (10) business days after written notice of the dispute, the parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in New York State, in accordance with the then current International Institute for Conflict prevention & Resolution Procedure, or to mediation by a mediator provided by the New York Public Service Commission. The Parties agree to participate in good faith in the mediation for a period of up to 90 days. If the Parties are not successful in resolving their disputes through mediation, then the parties may refer the dispute for resolution to the New York Public Service Commission, which shall maintain continuing jurisdiction over this Agreement.

6.3 Escrow: If there are amounts in dispute of more than two thousand dollars($2,000), the Interconnection Customer shall either place such disputed amounts into an independent escrow account pending final resolution of the dispute in question, or provide to the Utility an appropriate irrevocable standby letter of credit in lieu thereof.

VII. INSURANCE

7.1. Commercial General Liability: The Interconnection Customer shall, at its own expense, procure and maintain throughout the period of this Agreement the following minimum insurance coverage:

7.1.1. Commercial general liability insurance with limits not less than:

7.1.1.1. Five million dollars ($5,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than five (5) MWAC;

7.1.1.2. Two million dollars ($2,000,000) for each occurrence and five million dollars ($5,000,000) in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than one (1) MWAC and less than or equal to five (5) MWAC;

7.1.1.3. One million dollars ($1,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than or equal to 300 (kWAC) and less than or equal to one (1) MWAC

7.1.2. Any combination of general liability and umbrella/excess liability policy limits can be used to satisfy the limit requirements of Section 7.1.1 (a).

7.1.3. The general liability insurance required to be purchased in Section 7.1 (a) may be purchased for the direct benefit of the Utility and shall respond to third party claims asserted against the Utility (hereinafter known as "Owners Protective Liability"). Should this option be chosen, the requirement of Section 7.3(a) will not apply but the Owners Protective Liability policy will be purchased for the direct benefit of the Utility and the Utility will be designated as the primary and "Named Insured" under the policy.

7.2. General Commercial Liability Insurance: The Interconnection Customer is not required to provide general commercial liability insurance for facilities with an AC nameplate rating of 300 kW or less. Due to the risk of incurring damages however, the New York State Public Service Commission ("Commission") recommends that the Interconnection Customer obtain adequate insurance. The inability of the Utility to require the Interconnection Customer to provide general commercial liability insurance coverage for operation of the Unit is not a waiver of any rights the Utility may have to pursue remedies at law against the Interconnection Customer to recover damages.

7.3. Insurer Requirements and Endorsements: All required insurance shall be written by reputable insurers authorized to conduct business in New York. In addition, all general liability insurance shall, (a) include the Utility as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Utility shall not incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Utility prior to cancellation or termination of such insurance, with the exception of a ten (10) days' notice in the event of premium non-payment; provided that to the extent the Interconnection Customer is satisfying the requirements of subpart (d) of this paragraph by means of a presently existing insurance policy, the Interconnection Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Utility as required above.

7.4. Evidence of Insurance: Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnecting Customer. Prior to the Utility commencing work on System Modifications, and annually thereafter, the Interconnection Customer shall have its insurer furnish to the Utility certificates of insurance evidencing the insurance coverage required above.

> **7.4.1** If coverage is on a claims-made basis, the Interconnection Customer agrees that the policy effective date or retroactive date shall be no later than the effective date of this agreement, be continuously maintained throughout the life of this agreement, and remain in place for a minimum of three (3) years following the termination of this agreement or if policies are terminated will purchase a three-year extended reporting period. Evidence of such coverage will be provided on an annual basis.
>
> **7.4.2** In the event that an Owners Protective Liability policy is provided, the original policy shall be provided to the Utility.

7.5. Self-Insurance: If the Interconnection Customer has a self-insurance program established in accordance with commercially acceptable risk management practices, the Interconnection Customer may comply with the following in lieu of the above requirements as reasonably approved by the Utility:

> **7.5.1.** The Interconnection Customer shall provide to the Utility, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure to a level of coverage equivalent to that required.
>
> **7.5.2.** If the Interconnection Customer ceases to self-insure to the standards required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of the Interconnection Customer's financial ability to self-insure, the Interconnection Customer agrees to promptly obtain the coverage required under Section 7.1.

7.6. Utility Obligation to Maintain Insurance: The Utility agrees to maintain general liability insurance or self-insurance consistent with its existing commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

7.7. Notification Obligations: The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

VIII. LIMITATION OF LIABILITY

8.1 Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever. Nothing herein is meant to limit the liability of a Party to an unaffiliated third-party claimant.

IX. INDEMNITY

9.1 This provision protects each Party from liability incurred to third parties arising from actions taken pursuant to the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Section 7.

9.2 Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and hold the other Party (the "Indemnified Party") harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, to the extent arising out of or resulting from the Indemnifying Party's action or failure to meet its obligations under this Agreement, except in cases of negligence, gross negligence or intentional wrongdoing by the Indemnified Party.

9.3 If a Party is obligated to indemnify and hold the Indemnified Party harmless under this section, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual loss, as adjudicated by the Indemnifying Party's insurance carrier, net of any insurance or other recovery.

9.4 Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this section may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any unintentional failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

X. CONSEQUENTIAL DAMAGES

10.1 Other than as expressly provided for in this Agreement or pursuant to the utility tariff, neither Party shall be liable to the other Party under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability;

provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

XI. MISCELLANEOUS PROVISIONS

11.1 Beneficiaries: This Agreement is intended solely for the benefit of the Parties hereto, and if a Party is an agent, its principal. Nothing in this Agreement shall be construed to create any duty to, or standard of care with reference to, or any liability to, any other person.

11.2 Severability: If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

11.3 Entire Agreement: This Agreement constitutes the entire Agreement between the Parties and supersedes all prior agreements or understandings, whether verbal or written.

11.4 Waiver: No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. In the event that any agreement or covenant herein shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder.

11.5 Applicable Law: This Agreement shall be governed by and construed in accordance with the law of the State of New York.

11.6 Amendments: This Agreement shall not be amended unless the amendment is in writing and signed by the Utility and the Customer.

11.7 Force Majeure: For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

11.8 Assignment to Corporate Party: At any time during the term, the Interconnection Customer may assign this Agreement to a corporation or other entity with limited liability, provided that the Interconnection Customer obtains the consent of the Utility. Such consent will not be withheld unless the Utility can demonstrate that the corporate entity is not reasonably capable of performing the obligations of the assigning Interconnection Customer under this Agreement.

11.9 Assignment to Individuals: At any time during the term, the Interconnection Customer may assign this Agreement to another person, other than a corporation or other entity with limited liability, provided that the assignee is the owner, lessee, or is otherwise responsible for the Unit.

11.10 Permits and Approvals: Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction and for the operation of the Unit during the term of this Agreement.

11.11 Limitation of Liability: Neither by inspection, if any, or non-rejection, nor in any other way, does the Utility give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Unit and any structures, equipment, wires, appliances or devices appurtenant thereto.

ACCEPTED AND AGREED:

Interconnection Customer

Signature: Michael Brigandi

Printed Name: North Bedford Energy Storage 1, LLC Michael Brigandi

Title: Senior Director of Grid Integration

Date: 6/23/2023 Apr 10, 2024

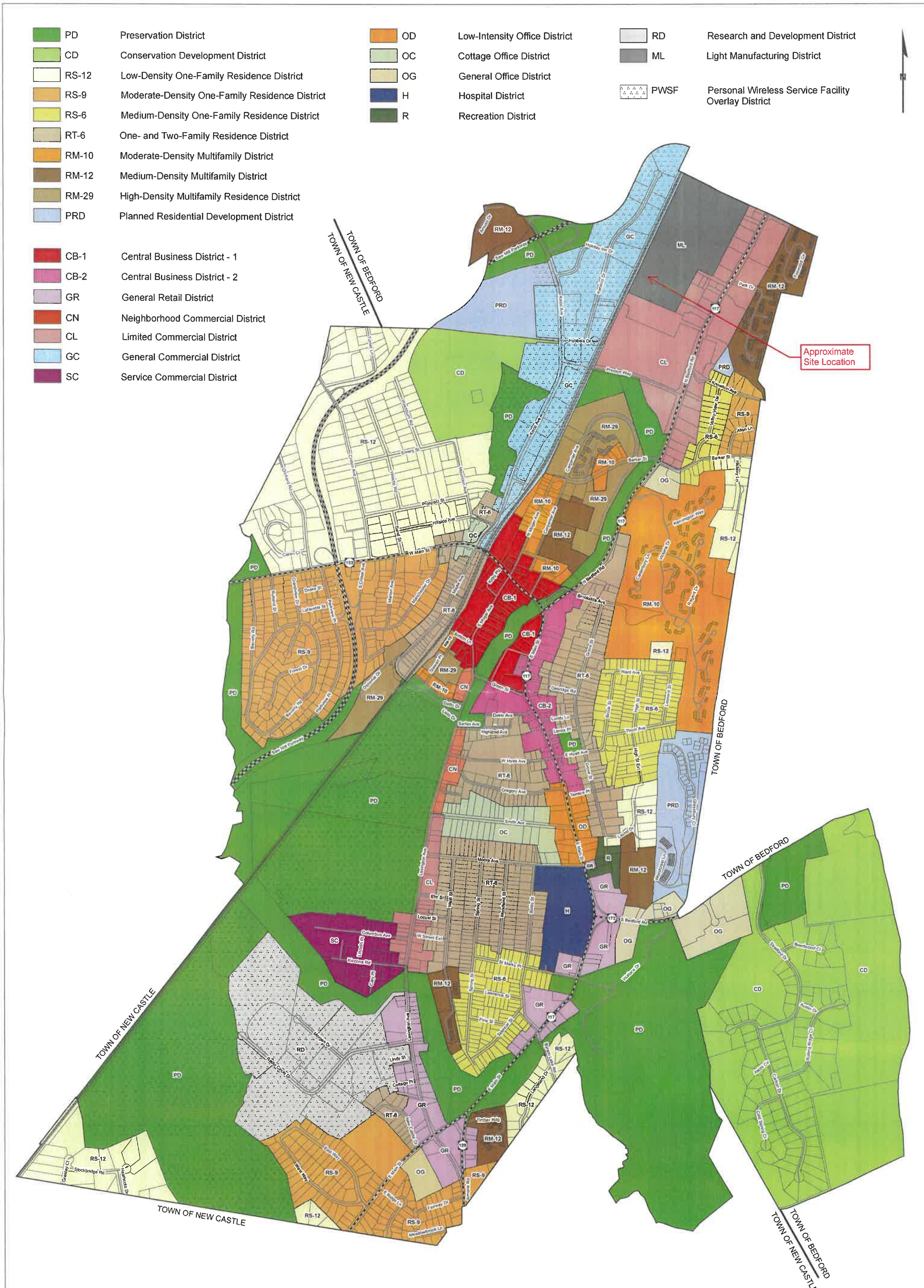
Utility Signature: Jones

Printed Name: Christopher Jones

Title: Chief Engineer

Date: 6/23/2023

Exhibit 11



ZONING DISTRICT MAP

VILLAGE/TOWN OF MOUNT KISCO

PREPARED BY KELLARD SESSIONS CONSULTING
500 MAIN STREET, ARMONK, N.Y.
(914) 273-2323

JANUARY 8, 2018

NOTE:
MUNICIPAL BOUNDARIES, PARCEL BOUNDARIES, ZONING AND OVERLAY DISTRICT BOUNDARIES, AND ROADS SHOWN HEREON HAVE BEEN PROVIDED BY THE VILLAGE/TOWN OF MOUNT KISCO OR BY THE WESTCHESTER COUNTY GEOGRAPHIC INFORMATION SYSTEMS (GIS). THIS MAP REFLECTS EXISTING ZONING CONDITIONS AND ZONING MAP AMENDMENTS APPROVED BY THE VILLAGE BOARD OF TRUSTEES SUBSEQUENT TO THE LAST ADOPTED VILLAGE ZONING MAP, DATED APRIL 21, 2003. MINOR ADJUSTMENTS HAVE BEEN MADE TO THE ZONING DISTRICT BOUNDARY LINES TO RESOLVE INADVERTENT ERRORS AND OMISSIONS ASSOCIATED WITH THE APRIL 21, 2003 ZONING MAP