STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources	))	Case 15-E-0751
Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions Implementing a Community Net Metering Program	))))	Case 15-E-0082

ORANGE AND ROCKLAND UTILITIES, INC.
IMPLEMENTATION PROPOSAL FOR VALUE OF DISTRIBUTED ENERGY RESOURCES FRAMEWORK
(REVISED)

Pearl River, New York
August 4, 2017

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ORANGE AND ROCKLAND UTILITIES, INC. IMPLEMENTATION PROPOSAL FOR VALUE OF DISTRIBUTED ENERGY RESOURCES FRAMEWORK

In its *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters* ("VDER Order"), the New York Public Service Commission ("Commission") required each New York investor-owned electric utility to file a proposal setting forth how each utility plans to implement the framework of the VDER Order.[1] Orange and Rockland Utilities, Inc. ("O&R" or the "Company") files this Implementation Proposal to satisfy the VDER Order requirements.

O&R continues to support New York State's clean energy goals[2] and the development of Distributed Energy Resources ("DER") in a way that benefits all customers. The VDER Order represented a major step toward establishing a vibrant DER market in New York that encourages the development of DER in ways that help meet the State's clean energy objectives and support electricity system needs. The Company is committed to continuing to work with the Department

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[1] Case 15-E-0751 et al., *In the Matter of the Value of Distributed Energy Resources, et al.*, ("VDER Proceeding"), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Order"), p. 136.
[2] Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Order Adopting a Clean Energy Standard (issued August 1, 2016) ("CES Order").

of Public Service Staff (“Staff"), stakeholders, and DER providers to implement the framework of the VDER Order in a timely and accurate manner.

I. Introduction and Background

The VDER Order specifically required utilities to put forward implementation proposals that addressed, at a minimum, the following items:

1. Calculation and compensation methodologies for Demand Reduction Value (“DRV”);

2. Identification of, compensation for, and mega-watt (“MW”) caps for Locational System Relief Value (“LSRV”) zones;

3. Proposed methods and values for providing Capacity Values for the Value Stack using Alternative 1 and Alternative 2;

4. Identification of average generation profiles for capacity and DRV compensation in projects’ first year of operation;

5. Cost allocation and recovery methodologies for each component of the Value Stack with emphasis on issues associated with capacity compensation;

6. The practicality of allocating and collecting costs associated with DER compensated under Phase One net energy metering (“NEM”);

7. Proposed accounting transactions and ratemaking treatment;

8. Utility processes for managing billing and tracking bill credits;

9. Reporting procedures for tracking progress in Tranches and any other necessary reporting; and

10. Draft tariffs stating the Market Transition Credit (“MTC”) for the residential and small commercial classes, for each tranche (including rules for how the MTC, DRV and LSRV will be applied to Community Distributed Generation (“CDG”) projects.[3]

This filing addresses each component in the sections below.

[3] Case 15-E-0082, *Proceeding on Motion as to the Policies, Regulations and Conditions for Implementing a Community Net Metering Program*.

II. Calculation and Compensation Methodologies for DRV and Identification, Compensation and MW Caps for LSRV Areas

In the VDER Order, the Commission required that all utilities develop proposals for the calculation and compensation of a DRV based on the value of reduced delivery costs associated with demand reduction across their service territories and calculated based on a disaggregation of utility marginal cost of service ("MCOS") during the ten peak hours. The VDER Order also directed all utilities to identify high value areas known as LSRV areas where DER has the potential to provide additional benefits.

As explained at the April 5, 2017 Technical Conference of this proceeding,[4] in determining LSRV areas the Company examined load areas where it plans investments, driven by load growth and reliability deficiencies as a result of its most recent planning process results and as identified in its five-year capital investment plan. The Company has identified these planned investments in part by applying its design standards to determine if its existing electric facilities will be operating outside of acceptable tolerances with respect to equipment loading, operating parameters and customer exposure within the upcoming ten-year planning period. The LSRV areas identified below represent high value areas where DER can benefit the distribution system by providing load relief that could assist existing facilities and equipment to operate at improved capacity and thermal levels or within design standards. Areas were chosen that align with potential infrastructure projects that are minimally three or more years in the future, and where there will be longer term value for implementing DER over time.

For each LSRV area, O&R established MW Caps for the amount of DER that would be eligible to receive compensation for LSRV. The Company determined the MW caps by

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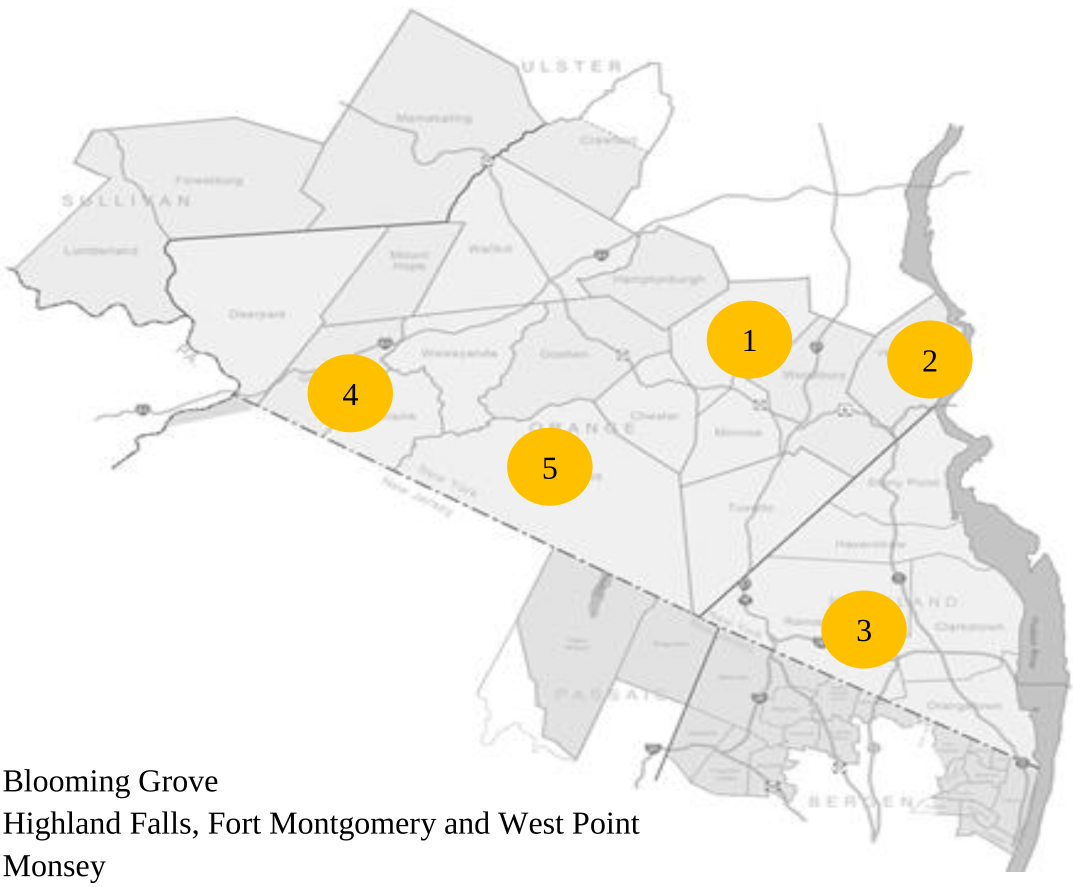
[4] VDER Proceeding, Notice of Technical Conference on Phase One of Value of Distributed Energy Resources (issued March 17, 2017).

identifying the amount of load relief that would be required to bring LSRV areas into alignment with design standards or to operate constrained areas at improved capacity and thermal operating levels, based upon future forecasted loads in the upcoming ten-year planning period, and based on system analysis that determined areas operating with higher exposure and operating risk under contingency conditions. MW caps calculated for each of the LSRV areas are set forth in Table 1 below.

The MW Caps may not necessarily represent the amount of load relief needed to defer traditional investments. The Company may adjust MW caps downward if additional reductions are procured through other price signal mechanisms, programs and/or non-wires alternative ("NWA") solicitations in an effort to defer the traditional investment. Should price signal mechanisms fall short in some of these areas, or if growth is greater than projected, there is the potential for the MW caps in these areas to increase based on future review and analysis. In some cases, there is the potential for LSRV, NWAs, or other price mechanism signals and programs to target and relieve the same locational constraints. In such instances, LSRV will work in conjunction with the Company's NWAs and other programs/mechanisms to encourage the construction and operation of DER projects that can operate at the time of the local area's distribution systems' constraint to potentially defer distribution investments. Therefore, such LSRV projects would need to be considered by the Company when determining the MW need for future NWA solicitations. To avoid double payments, projects receiving LSRV will not be compensated by additional NWA procurement mechanisms. The Company will determine actual qualification for the LSRV on a project-by-project basis depending on the location of the project and the date the project executes its interconnection agreement.

Using the above described methodology, O&R has designated geographic areas that represent over 140 MW of existing normalized load, on a peak load weighted basis (or approximately 12 percent of the Company's total New York system load), as eligible for LSRV. Figure 1 below displays the initial LSRV areas.

Figure 1: Initial O&R LSRV Areas[5]



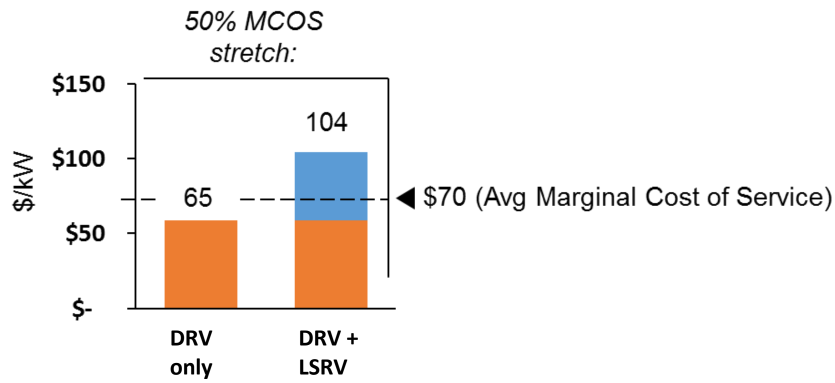
1. Blooming Grove
2. Highland Falls, Fort Montgomery and West Point
3. Monsey
4. Port Jervis
5. Warwick

The Company filed its current MCOS study and work papers with the Commission on March 23, 2017 in accordance with the VDER Order.[6] The marginal cost is expressed as a

[5] The areas identified on this map are for illustrative purposes only. Upon Commission approval of this implementation plan, the Company will publish detailed boundaries of these LSRV areas.
[6] VDER Proceeding, Orange and Rockland's Marginal Cost of Service Study and Workpapers (filed March 23, 2017)

System-Weighted Marginal Cost as dollar per kW value and was developed through analysis of planned electric delivery system upgrades related to load growth, primarily at the substation and transmission system level. Generally, the marginal cost is zero in areas with excess capacity. Historically, the Company has not developed estimated values for specific load areas. Because O&R's existing MCOS study does not provide locational differences, the Company applied engineering system analysis and experienced judgment to establish a combined LSRV/DRV in the constrained areas of approximately $104/kW-year based on 150 percent of the current average system–wide MCOS level of $70 as shown in Figure 2 below. This methodology will be further enhanced once the Company completes an updated, more granular MCOS study as discussed in the Company's April 24, 2017 Work Plan filing.[7] Table 1 below displays the associated values and corresponding MW Caps for the identified LSRV areas.

Figure 2. Deaveraging of MCOS Study into DRV and LSRV Prices



[7] VDER, Work Plan of Consolidated Edison Company of New York and Orange and Rockland Utilities, Inc. to Determine Locational Values of Distributed Energy Resources (filed April 24, 2017).

Table 1: LSRV Areas, Values, and MW Cap

Area	LSRV ($/kW)	MW Cap
Blooming Grove	39.61	3.4
Highland Falls, Fort Montgomery & West Point	39.61	10.5
Monsey	39.61	2.5
Port Jervis	39.61	4.3
Warwick	39.61	4.7

III. Methods for Providing Capacity Values Using Alternative, 1 Alternative 2, and Alternate 3

A. Determination of Generating Capacity Credits for Capacity Alternative 1

The VDER Order adopts as the default capacity credit for intermittent resources Staff's Alternative 1, which instructs utilities to select "the capacity portion of the supply charge for a service class with a load profile most similar to solar generation profile that could be used for each kWh of generation all year."[8]

To determine which service class is most applicable to solar photovoltaic ("PV") systems, O&R examined the characteristics of service class load profiles used in the capacity charge calculation for full-service customers. For each service class, the capacity portion of the supply charge can be calculated on a $/kWh basis by multiplying the service class peak kW at the one-hour New York Control Area ("NYCA") system peak by Installed Capacity ("ICAP") market costs (including losses), and dividing by the seasonal energy usage for the service class. On a unitized $/kWh basis, the capacity cost is a function of the ratio of the coincident peak (kW-peak) to the energy use ("kWh") so the appropriate comparison for a solar PV profile to a customer service class profile for capacity costs is this ratio of coincident peak to kWh usage ("kW-peak to kWh ratio").

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[8] VDER Proceeding, VDER Order, p. 99.

The kW-peak to kWh ratio can also be approximated for solar PV systems and the results compared to service class ratios to determine the appropriate capacity rate. Using the E3 NREL Solar PV generation profile (as included in the DPS Staff Whitepaper in this proceeding),[9] a 2 MW solar PV system in the O&R service territory could expect to produce 1,509,369 kWh in the summer capability period (May through October). Averaging the hourly solar PV production during the capability period, that 2 MW solar PV system could expect to generate an average of 361 kW during the 5:00 P.M. NYCA peak. Therefore, a solar PV's kW-peak to kWh ratio is 361 kW to 1,509,369 kWh or approximately 1 kW to 4,176 summer kWh. Table 2 below shows the calculated ratios for various service classes during O&R's 2016 summer and annual capability period as compared to a 2 MW solar PV system:

Table 2. kW-peak to kWh Ratios for Various Service Classes and Solar PV[10]

	kW-peak	Summer kWh	Winter kWh	Annual kWh	kW-peak to kWh (summer)	kW-peak to kWh (winter)	kW-peak to kWh (annual)
SC 1	559,698	839,496,000	707,050,000	1,546,546,000	1 to 1,500	1 to 1,263	**1 to 2,763**
SC 2 - Secondary	199,920	460,776,000	424,981,000	885,757,000	1 to 2,305	1 to 2,126	**1 to 4,431**
SC 3	51,154	191,935,000	170,906,000	362,841,000	1 to 3,752	1 to 3,341	**1 to 7,093**
2 MW Solar PV	361	1,509,369	1,206,886	2,716,255	1 to 4,176	1 to 3,339	**1 to 7,515**

The O&R service class load profile that most closely resembles a typical solar PV system from a kWh to kW-peak ratio perspective, for the purpose of the installed capacity rate, is Service Classification 3 – General Primary Service ("SC 3").[11] SC 3 is part of the Group C category of capacity rates as detailed in General Information Section No. 15 of the Company's

[9] VDER Proceeding, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding (filed October 27, 2016).
[10] Based on the winter capability period (November 2016 – April 2017) and the summer capability period (May 2017 – October 2017).
[11] P.S.C. No. 3 – Electricity, Orange and Rockland Utilities, Inc.

electric tariff, P.S.C. No. 3 Electricity ("Electric Tariff"). The Company therefore will use the $/kWh rate included in the Market Supply Charge ("MSC") for SC 3 customers for the Generating Capacity credit rate for Alternative 1 projects. This rate will be calculated and posted at the beginning of the summer and winter capability periods based on the results of the New York Independent System Operator's ("NYISO") strip auctions.

B. Determination of Generating Capacity credits for Capacity Alternative 2

Under Alternative 2, O&R will take the capacity costs for the same SC 3 service class and divide that lump sum by energy (kWh) usage for the SC 3 class during the 460 peak summer hours that occur starting with hour 14:00 and going through hour 18:00 for each day in June, July, and August. This creates a $/kWh rate that will be paid to Value Stack customers who select this alternative for their exports to the electricity grid during those 460 hours.

For Alternative 2 projects, the Company will post the applicable Generating Capacity Rate 2 credits by May 15 each year applicable to that capacity year (May through the following April). Customers electing to exercise their one-time irrevocable election to change from Alternative 1 to Alternative 2 must notify O&R prior to May 1 to be effective in May.

C. Determination of Generating Capacity credits for Capacity Alternative 3

For Alternative 3 projects, O&R will determine actual Generating Capacity credits annually based on a project's actual export of power, as measured at the O&R meter, coincident with the NYCA peak load during the prior summer. The coincident production will be used for the 12 months beginning the following May and will be valued each month based on the applicable NYISO spot auction clearing prices multiplied by the applicable capacity reserve requirements (including gross up for demand curve excess). The applicable prices and reserve requirements are Lower Hudson Valley and Rest of State ("ROS").

Set forth below is an example of the Generating Capacity credit applicable in May 2017 for a project in O&R's service territory with 1,000 kW of coincident exports from 2016.

Table 3: Example of the Generating Capacity Credit

May 2016	**G-J**	**ROS**	**Total**
UCAP Requirement	$10.50	$3.00	
Effective Requirement	$11.54	$4.18	
Weighted Price ($/kW)			$11.66
Project Coincident Peak	1,000 kW		$11,660*

Until an eligible project has been in operation during the NYCA peak, O&R will estimate the anticipated coincident peak export based on anticipated availability of the specific generation technology.

IV. Methods for Providing Market Transition Credit ("MTC") Values

A. Determination of the Market Transition Credit

The Company has calculated the MTC that will be applicable to eligible CDG projects[12] receiving value-stack credits for the portion of their output that is allocated to either Service Classification No. 1 - Residential Service ("SC 1") customers or the non-demand billed subset of customers taking service under Service Classification No. 2 – General Primary or Secondary

[12] See note 3, *supra*.

Service ("SC 2") (small commercial non-demand billed) based on the project's assigned tranche. The MTC rates will be fixed for 25 years.

The O&R calculations, which are detailed in Table 5 below, follow the methodology outlined in Appendix A of the VDER Order with updates to input values as directed by the VDER Order. Specifically, the Company updated delivery rates to reflect its current 2017 delivery rates (using only the higher summer tail-block for SC 1 even though some of the solar PV production is likely to displace the lower initial block), and updated both the MSC and the historical Day Ahead ("DA") Locational Based Marginal Price ("LBMP") revenues that a solar PV facility is expected to receive as part of the NYISO Zone G - Hudson Valley prices.

The MTC calculation process starts with a calculation of the base retail rate using the three year average of the Merchant Function Charge ("MFC"), System Benefits Charge ("SBC") and MSC rates from 2014 through 2016.[13] The current 2017 delivery rate, with the summer and winter rates weighted by the anticipated seasonal production of solar systems, is added to determine the base retail rate.

The base retail rate is then compared to the estimated Value Stack revenues a solar PV project would receive for renewable energy credits ("RECs"), ICAP, and DA LBMP.

The difference between the base retail rate and the Value Stack unitized rate is the MTC for Tranche 1. The differences between 95 percent and 90 percent of the base retail rate and the Value Stack determine the respective Tranche 2 and Tranche 3 MTCs.

The same analysis was repeated for SC 2– Non-Demand Billed and both are summarized in Table 4.

[13] See VDER Proceeding, VDER Order, Appendix C-1.

Table 4: MTC Calculations for SC No. 1 and SC No. 2 (Non-Demand Billed)

Base Retail Rate	SC1	SC2
MFC	0.0072	0.0042
SBC	0.0045	0.0045
Delivery	0.0785	0.0567
ICAP	0.0288	0.0228
Retail commodity charge less capacity	0.0608	0.0614
Total Base Retail Rate	0.1798	0.1496
Estimated Value Stack		
Environmental	0.0242	0.0242
Generating Capacity	0.0288	0.0228
DA LBMP	0.0489	0.0489
Total Estimated Value Stack	0.1019	0.0959
Tranche 1 MTC	**0.0779**	**0.0537**

Solar PV MTC by tranche & service class

	SC1			SC2	
	% of Retail Rate	Base Retail Rate	MTC	Base Retail Rate	MTC
Tranche 1	100%	**0.1798**	**0.0779**	**0.1496**	**0.0537**
Tranche 2	95%	**0.1708**	**0.0689**	**0.1421**	**0.0462**
Tranche 3	90%	**0.1618**	**0.0599**	**0.1346**	**0.0387**

Each MTC will be applied to the energy (kWh) output of each CDG project and multiplied by the project's percentage allocation to residential customers for the SC1 MTC and the percentage allocation to small commercial subscribers for the SC 2 MTC, respectively. The

DRV is then applied only to the portion of the project allocated to demand-billed customers that are not eligible for an MTC.

V. Identification of Average Generation Profiles for Capacity and DRV Compensation in Projects' First Year of Operation

A. Capacity Rates in a Project's First Year of Operation

Until an eligible project has been in operation for one NYISO generation capability period, O&R will estimate an initial ICAP rating based on the anticipated availability of the specific generation technology multiplied by the potential export (AC rating of project less customer load at peak).

B. DRV/LSRV Rates in Project's First Year of Operation

Until a project eligible to receive DRV or LSRV credits is in operation coincident with O&R summer peaks, it will receive initial DRV and/or LSRV credits based on the anticipated production of that technology. For solar PV projects, O&R has applied the E3 NREL profile (as included in the DPS Staff Whitepaper in this proceeding) for O&R's service territory to determine the initial credits that will be applied until project-specific operational data is available (see Table 5 below).

Table 5. Initial DRV and LSRV Pricing for Solar Resources

	Values Based on E3 NREL Solar Production
Coincidence O&R Peak	17.6%
Initial DRV ($/kW-yr)	$11.40
Initial LSRV ($/kW-yr)	$6.97
LSRV + DRV ($/kW-yr)	$18.37

For other intermittent technologies eligible for LSRV/DRV credits, O&R will develop an initial credit based on the anticipated production, analogous to the application of the E3 NREL data above. For dispatchable technologies, O&R will multiply the anticipated availability of the technology by the potential export using the AC rating of the project less any host customer load.

VI. Cost Allocation and Recovery Methodologies Implementing the Principles Adopted for Each Component of the Value Stack

Generally, the Company will seek to recover the market-based costs for Value Stack credits from full-service customers for those components from which only full-service customers benefit. Value Stack components which provide benefits to all customers, or any portion of the Value Stack payment that are "out of market", will be recovered from delivery customers with additional differentiation if the benefits accrue only to lower voltage customers. Where no specific benefit has been identified and valued, the Company will allocate costs for those components in proportion to the service classes that receive that portion of the credits. Table 6 shows how Value Stack components will be allocated to segments of the utility customer base, the specific cost recovery methods proposed, the method for allocating those costs, and the applicable rate recovery units. To the extent incremental capital expenditures associated with implemented new requirements established in this proceeding, cause the Company to exceed its net plant target, the Company will defer the carrying charges on the expenditures above the target until the next time base rates are reset. Similarly, all incremental O&M costs associated with implementing the requirements in this proceeding will be deferred until the next times base rates are set.

Table 6. Cost Allocation and Recovery of Value Stack Payments

Value Stack Components	Customer Segment Bearing Costs	Cost Recovery Method	Allocation Method	Rate Recovery Units
Energy	Full-Service Supply Customers	Market Supply Charge	Included in supply rate	$/kWh
Generating Capacity - Market Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC	$/kWh or $/kW
Generating Capacity - Out of Market	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	$/kWh or $/kW
Environmental - Market Value	Full-Service Supply Customers	Market Supply Charge	Included in supply rate	$/kWh
Environmental - Out of Market	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	$/kWh
Demand Reduction Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC, separating high and low voltage benefits	$/kWh or $/kW
Locational System Relief Value	Delivery Customers	VDER Delivery Surcharge	Load-ratio share by SC, separating high and low voltage benefits	$/kWh or $/kW
Market Transition Credit	Delivery Customers	VDER Delivery Surcharge	Pro rata per SC credit share*	$/kWh

*SC credit share recovers the Value Stack component credits from the specific service classes that received the credits.

Energy

Payments provided to Value Stack customers for energy produced will be allocated for recovery to all full-service utility supply customers. Cost recovery will occur by adding such energy payments to the MSC accounts used to track and collect the full-service utility supply charge and will be allocated to all full-service utility supply customers.

Full-service utility supply customers will receive the offsetting benefits of the energy produced by Value Stack customers by having the 'export channel' of the interval metering at the Value Stack customer's premise credited to O&R's load-serving entity ("LSE") account in the Transmission Owner Load ("TOL") file which the Company provides to the NYISO for wholesale billing purposes. The exports will appear as a decrement in the O&R LSE portion of the TOL file, thereby reducing the amount of energy which the Company purchases from the NYISO on behalf of O&R's full-service customers.

Generating Capacity

All customers will receive the offsetting benefits of load reduction from capacity injections made by Value Stack customers, because all customers will benefit from an overall reduction in capacity purchase obligations that will occur as a result of the load reduction during the NYCA peak hour. Because there is currently no framework for bidding the capacity associated with distributed Value Stack generation into the NYISO wholesale markets, it is not possible for only full-service utility supply customers to benefit directly from Value Stack payments for generating capacity.

As noted in the VDER Order, the Generating Capacity Value Stack credits may vary from the actual value provided. Therefore, the Company will identify the market value and the 'out of market' portion of the Value Stack credits for these components.

The market value will be determined by multiplying the generation from all Value Stack customer-generators on the peak hour from the previous year by the average price for generating capacity. Cost will be recovered via a new VDER Delivery Surcharge on a per-kW basis for service classes with demand charges, and on a per-kWh basis for non-demand billed service classes.

The out-of-market value for the Value Stack Generating Capacity component is the difference between the market value and the total Generating Capacity payments made to Value Stack customers. The out-of-market value will be allocated to all delivery customers via the VDER Delivery Surcharge, with allocation among service classes based on the pro rata share of the credits received for the out-of-market portion of this component per service class. Cost recovery will be on a per-kW basis for service classes with demand charges, and on a per-kWh basis for non-demand billed service classes.

Environmental Benefit

The market value of the payments provided to Value Stack customers for RECs will be allocated to all full-service utility supply customers. Cost recovery will occur by adding such REC payments to the accounts used to track and collect REC charges to meet the obligations of O&R's full-service utility supply charges through the MSC. Because MSC costs are charged on a per-kWh basis, these costs will be automatically allocated among full-service utility supply customers in all service classes according to each service class's full-service utility supply customer usage.

A portion of the Value Stack credits associated with RECs may be more or less than the market value of those RECs. This can occur because the VDER Order requires utilities to purchase RECs from individual VDER customer-generators at fixed prices for a 20-year term.

As a result of this long-term requirement, it is likely that the market value of RECs will vary from the weighted average cost of RECs purchased from Value Stack customers. Therefore, O&R will establish a tracking account which estimates the variance between the two different procurement methods. The variation between these two accounts, which could be either positive or negative in any given year, will be collected from, or credited to, all delivery customers via the VDER Delivery Surcharge.

Demand Reduction Value and Locational System Relief Value

The DRV and LSRV credits provided to Value Stack customers will be collected from all delivery customers. In accordance with the VDER Order,[14] during the calculation of LSRV and DRV credit rates the Company will establish which portions of the LSRV and DRV credits are associated with the lower voltage portion of the system (secondary system costs) and which portions are associated with the higher voltage of the system (primary system costs and above). The secondary system distribution customers will pay both the lower voltage and higher voltage portions of the LSRV and DRV, while the primary system and higher voltage level distribution customers will pay only the higher voltage portions of the LSRV and DRV. Recovery will occur via the VDER Delivery Surcharge. For demand-billed service classes, the surcharge design will collect the VDER surcharge via per-kW rate. For energy-only service classes, the surcharge design will collect the VDER surcharge via per-kWh rates.

Market Transition Credit

The payments to Value Stack customers for the MTC will be allocated to all mass-market delivery customers. Costs will be allocated among the mass-market service classes in proportion to the MTC provided to each service class in the previous calendar year. In the first year, the

[14] VDER Proceeding, VDER Order, p. 52.

surcharge will be allocated according to the pro rata share by mass-market service class of generating capacity of behind-the-meter, net metering eligible generation. Recovery will occur via the new VDER Delivery Surcharge.

VII. The Practicality of Allocating and Collecting Costs Associated with DER Compensated under Phase One NEM

O&R currently recovers costs for net metering via two methods: (1) revenue shortfalls that occur due to reduced usage and carried-forward exports which are used in subsequent billing periods are collected via the natural operation of the Revenue Decoupling Mechanism ("RDM"); and (2) financial credits (*e.g*., credits applied to Remote Net Metered ("RNM") satellite customers) or cash payments (*e.g*., annual cashouts paid to residential customers) are collected via SC-specific revenue adjustments to the RDM.

The Company notes that this cost allocation and recovery approach preserves some of the inefficiencies of NEM. The Company may seek to alter cost recovery approaches for NEM and Phase One NEM to better align with the more appropriate approach established for Value Stack customers and collect financial credits related to NEM and Phase One NEM in a new service-class specific NEM Delivery Surcharge. One exception, however, will be the cost recovery for RECs produced by Phase One NEM CDG projects that do not opt for the "Customer Retention" of RECs. For these projects, the "interconnecting LSE," O&R, will retain the REC which is eligible for use in compliance with the Renewable Energy Standard requirements for LSEs. An imputed price for the market value of RECs from these Phase One NEM CDG projects will be included in the collections associated with the MSC, with any below- or above-market costs collected or refunded via the NEM Delivery Surcharge, similar to the treatment afforded to Value Stack RECs and recovery of those costs via the MSC and the VDER Delivery Surcharge.

VIII. Accounting Transactions and Ratemaking Treatment

Attached as Appendix A is O&R's proposed Federal Energy Regulatory Commission ("FERC") accounting treatment related to the components of the Value Stack, as well as any RECs acquired by the Company as part of Phase One NEM.

IX. Managing Billing and Tracking Bill Credits

Phase One NEM Customers

The Company will establish new business processes for customers served under the new VDER tariff as Phase One NEM customers. These business processes will generally follow the business processes for traditional NEM customers, with some substantive differences. First, as required by the VDER Order, residential customers will no longer be cashed-out for excess credits at the end of the annual period. Instead, excess credits for residential customers will roll forward onto subsequent bills. Second, because the VDER Order established a time period during which customers would be eligible for VDER Phase One NEM (as well as other forms of Phase One crediting), the Company will track the in-service date for each Phase One NEM customer (or the host, for Phase One NEM CDG projects) for the purpose of recording and tracking each customer's eligibility for Phase One NEM treatment. Third, like Value Stack customers, all Phase One NEM customers, except for customers served under energy-only rates, will be required to install an O&R Advanced Metering Infrastructure ("AMI") meter, capable of separately tracking imports and exports on an hourly basis. Finally, all Phase One NEM customers, as well as traditional NEM customers, will have a one-time option to transfer to service under the Value Stack framework.

Value Stack Customers

1. Customer Enrollment and Data Collection. The process of enrolling customers under the Value Stack tariff will be similar to current processes for enrolling traditional net metered customers. For non-CDG Value Stack customers, the customer enrollment process will be initiated during the interconnection of the VDER-eligible generation resource. Each customer will notify O&R's Technology and Automation Engineering group during the interconnection process of their request for service under the VDER tariff (similar to the process for traditional NEM customers). During the interconnection process, the Company will collect the customer data needed to establish a VDER account and to interconnect the resource.

   For CDG Value Stack customers, enrollment may occur during the interconnection process for the initial group of subscribers, or can occur at a later date as the host enrolls and de-enrolls CDG participants. In either instance, the project host will inform O&R of the name, account number and initial allocation percentage of the customers being enrolled in the CDG project in accordance with the existing CDG Operating Procedural Requirements found on the O&R website.[15] The project host must also provide O&R with the alternative method selected for the Generating Capacity portion of the Value Stack.

2. Metering. A customer request for service under the VDER tariff will trigger the installation of the appropriate meter, which for Value Stack customers will be a Commission approved AMI meter, capable of separately tracking imports and exports. The import data from the AMI meter will be used in calculating customer billing, including charges for delivery and supply. The export data from the AMI meter will be used to calculate Value Stack payments.

[15] https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection

Installation of an AMI meter is a requirement for a mass market customer to participate in the Value Stack tariff.

3. Rate Vintaging and Rate Eligibility. The compensation received by Value Stack customer-generators will differ depending on the service class of the customer receiving the Value Stack credits and the date the individual customer-generator is interconnected or opts-in to Value Stack treatment. Accordingly, the Company will establish business processes to track the interconnection date and the associated VDER rate treatment for each customer-generator. These processes will include tracking the service class of the participating customer, the relative proportion of mass market and non-mass market customers in CDG projects, the initial interconnection or opt-in date (for use in determining the appropriate MTC level), as well as vintaging of rates. These vintaged rates will include the Environmental Value (locked in for individual customers for 20years), and LSRV (locked in for individual customers for ten years).

4. Establishing Value Stack Rates.

    a. Energy. The crediting rate for hourly energy injections by Value Stack customers will be sourced from the same data set that is used to bill O&R's Mandatory Day-Ahead Hourly Pricing ("MDHP") customers. This data set contains Hourly DA-LBMP prices including a factor which adjusts the DA-LBMP price to account for losses in the distribution system.

    b. Generating Capacity. There are three different methods for crediting Value Stack customers for generating capacity. Customer-generators with intermittent generation will have a one-time opportunity to select among Alternative Method 1, Alternative Method 2 or Alternative Method 3, as described below. All customer-generators with dispatchable generation will be required to receive generating capacity credits under Alternative Method 3. Capacity prices will be sourced from the Con Edison Energy Management organization, from the same data set that is used to determine capacity charges for O&R's full-service customers.

c. Environmental Value. O&R will use the higher of the REC price published by NYSERDA for its most recent Tier 1 REC procurement or the net Social Cost of Carbon as calculated by Staff[16], in effect at the time of the customer-generator's interconnection to set the Environmental Value credit for that customer-generator. The Environmental Value compensation rate will be fixed for the term of each customer-generator's eligibility for the VDER tariff.

d. DRV and LSRV. The DRV rate applicable to a specific customer-generator's performance will be the then-in-effect DRV rate as determined by the Company, and will change as that DRV rate is updated. The LSRV rate will be the rate in effect at the time of the customer-generator's interconnection, and will be fixed at that value for ten years from that customer generator's commencement of generation. Existing customers will not be eligible to participate in an LSRV after the first ten year period.

e. MTC. The MTC rates will be established subject to a Commission order in this proceeding approving O&R's proposed MTC rates, one each for SC 1 and SC 2 – non-demand billed customers.

5. Reading the Generator Meter. The Company will calculate the Value Stack bill credits on a regular monthly billing cycle basis based on readings from the AMI meter located at the

[16] VDER Proceeding, VDER Order, p.106, n. 42.

generation site. O&R's meter data processes will be adjusted, and updated as necessary, to capture both import and export data at the VDER AMI meter.

6. Application of Value Stack Bill Credits. The Company will calculate bill credits within five business days following each meter read of the customer-generator's billing meter, as practicable. For projects eligible for either the DRV or the LSRV credit, O&R will determine the credits annually, divide by twelve and credit the customer with twelve equal monthly amounts, beginning in January of the following year. The calculation methodology for each component of the Value Stack bill credit is set forth in section XI below.

7. Placing Credits on Customer Bills.

    a. CDG Customers. The Company will take the sum of all the monthly Value Stack credits and allocate those credits to each individual CDG subscriber according to the percentage allocation of credits provided by the CDG host prior to the start of each billing cycle in accordance with the Company's CDG Operating Procedural Requirements. Credits will be placed on the bill in the form of a dollar credit applied after regular customer charges are calculated. Customers whose credits exceed the total amount of the bill will receive a zero bill and excess financial credits will be held on those customers' accounts to be applied against bill charges in the subsequent billing cycle.

    b. RNM Customers. The Company will calculate the sum of all the monthly Value Stack credits and apply them to the Host account first; the remainder will then flow to the satellite accounts in the order in which they are billed. Credits will be placed on the bill of each satellite account in the form of a monetary credit applied after regular customer charges are calculated. For any individual satellite account whose credits exceed the total amount of the bill, the satellite account will receive a zero bill and excess financial credits will be passed on to the next satellite customer's account. If there are credits remaining after all accounts in the RNM group have received their appropriate allocation, the excess financial credits will be carried forward, on the host account, to the subsequent billing cycle to be applied against future satellite bills.

c. Non-CDG, Non-RNM Value Stack Customers. For Value Stack customers that are neither CDG nor RNM, O&R will take the sum of all the monthly Value Stack credits and apply those credits to those customers' bills in the form of a monetary credit applied after regular customer charges are calculated. If the credits exceed the total amount of the bill, the excess financial credits will be carried forward to the subsequent billing cycle to be applied against the customer's future bills.

Traditional NEM Customers

As required by the VDER Order, the Company will modify its billing procedures for the hosts and subscribers of CDG projects that are installed under traditional NEM regulations, as it relates to the carry-over of CDG credits. The Company will develop business processes to monitor CDG host accounts to comply with the new requirement that hosts be allowed to carry-forward credits for a grace period of up to two years. Doing so will require new monitoring of host accounts for excess credits retained after the annual period and the disposition of those credits within the subsequent two-year period.

Customer Care and Customer Communications

1. Staffing Requirements. O&R is evaluating the current staffing level within its Customer Operations organization to determine the appropriate number of employees and

contractors it will require to respond to the requirements of the VDER Order as well as the anticipated customer and DER provider related inquiries

2. Bill Presentment for Value Stack. Because many of the bill credits (*e.g.*, DRV, LSRV and Generating Capacity Alternative 3) are performance based and decoupled from the project's monthly kWh production, O&R will not provide a separate display of kWh performance on the bill, as is done for current traditional net metered customers. The bill will, however, indicate that the dollar credit being applied to the customer's bill is the result of participating in the VDER program. The total credits of a CDG project in each billing cycle will be allocated to the project's subscribers based on the allocation percentages provided for the project. These credits will be applied to individual subscribers as monetary credits based on the subscribing customers' individual billing cycles.
3. Displaying Data for CDG Hosts. Based on feedback from CDG hosts and developers, O&R will develop a monthly report to provide data to CDG hosts regarding the following items: total billing cycle generation, total billing cycle bill credits, and a subscriber list showing customer name, account number, percentage allocation and dollar allocation. O&R will evaluate the level of detail of the bill credits to be provided to the CDG host and plans to share its preliminary thoughts with developers at a training session to be scheduled this summer.
4. CDG Host Access to Subscriber Data. As outlined in the Company's existing CDG Procedural Requirements, O&R will provide the CDG Host with subscriber customer energy usage information upon the Host's self-certification that it meets all criteria for

customer authorization. O&R is evaluating additional processes for the provision of customer data.

It is important to note that changes may be made to the above information sharing between the Company and participating DERs to conform with any orders issued in the pending proceeding addressing Commission oversight of DER providers.[17]

<u>Automatic and Computerized Bill Processing</u>

As the Company gains experience with administering the adoption of the Value Stack, O&R will determine the appropriate level of automation and computerization that balances the costs and benefits of billing and crediting Value Stack and other VDER customers. This will require a detailed analysis of the Company's current billing system and the potential upgrades needed to automate the billing of these customers. To the extent that automating the Value Stack for the purposes of billing and tracking credits requires significant incremental resources or investments, O&R will seek to recover those costs in base rates.

<u>Tracking Credits; Interface with Accounting and Energy Management</u>

Regardless of the level of automation and computerization adopted for billing Value Stack customers, O&R will be able to track the bill credits that are provided to customers, for purposes of cost allocation and cost recovery. The Company will establish business processes that will assign the costs associated with the Value Stack components to the appropriate cost and revenue accounts for recovery from customers. The Company will also establish processes so that the value components that can specifically be used to serve the requirements of O&R's full service

[17] Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products.*

customers are incorporated into the Company's procurement processes, (*e.g.*, for energy and RECs which are procured by Con Edison's Energy Management group on behalf of O&R).

X. Reporting Procedures for Tracking Progress in Tranches and Any Other Necessary Reporting

The VDER Order established reporting guidelines for the Phase One NEM Mass Market MW Trigger and the VDER Order Value Stack Tranches requiring "regular reporting by the utilities and explicit notice when 85 percent of the allocation is reached" in all Tranches.

O&R's project's tranche assignments are tracked and communicated through a combination of manual Excel entry and via a portal. This portal allows customers to enter application information, attach supporting documents, and electronically submit interconnection applications. All applications received by the Company after April 29, 2016, have been received through a portal.

As projects enter a tranche, their tranche position is notated in the portal and project developers are notified of for the project's tranche position. As projects enter a tranche, an Excel table tracking tranche capacity is updated and the percentage of the capacity of each tranche is noted. The VDER Order requires a utility to notify the Commission when 85 percent of the total MW capacity of all tranches in its territory is reached. O&R sent such a notification on April12, 2017.

Reporting of tranche capacity shall be shared on the portal @https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection and reported to the Commission electronically on a timely basis. In addition to posting tranche capacity online, O&R alerts developers via the portal and stores the information on the application for each project as reference. As noted above, when applicants log in via the portal, their tranche data is displayed alongside other relevant project information.

XI. Draft Tariffs: Market Transition Credit for Residential and Small Commercial Classes

O&R proposes to change the name of the existing Rider N from "Net Metering for Customer Generators" to "Net Metering and Value Stack Tariff for Customer Generators." Common provisions such as the Applicability Section, Metering Section, and Interconnection Section of the existing Rider N will continue to apply to customers eligible for Phase 0 Net Energy Metering, Phase 1 Net Energy Metering, and the Value Stack Tariff. The Company will amend the billing Section of the current Riders to state that the existing Billing Section is only applicable to Phase 0 and Phase 1 Net Energy Metering customers. The draft tariff language is attached as Appendix B.

O&R also proposes to file a new statement "VDER" that will contain certain values of the Value Stack.

XII. Conclusion

The Company respectfully submits this Implementation Proposal in response to the VDER Order's directive, and looks forward to further engagement with Staff and stakeholders during and after the comment period on this Implementation Proposal.

Dated: May 1, 2017

Respectfully submitted,

ORANGE AND ROCKLAND UTILITIES, INC.

By: */s/ John L. Carley*

John L. Carley
Associate General Counsel
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003
Tel.: 212-460-2097
Email: carleyj@coned.com

Appendix A

Appendix A. Proposed FERC Accounting Treatment of VDER (Components (Revised)

	Customer Credits Company credits to customers for the acquisiton of the load			**Recovery Revenue** Customer charges		**Deferral Accounting**		
Value Stack Component and MTC	FERC Acct db		FERC Offset cr	FERC Acct cr	FERC Offset db	Deferral	Offset (b)	
Energy	555		142/232	440-444	142	182.3/254	555	Commodity
Capacity Best Estimate avoided	555		142/232	440-444	142	182.3/254	555	Commodity
Capacity Best Estimate difference	555		142/232	440-444	142	182.3/254	555	Delivery
Environmental - REC credit	555	(a)	142/232	440-444	142	182.3/254	555	Commodity
Environmental - O/U REC	555	(a)	142/232	440-444	142	182.3/254	555	Delivery
Demand Reduction Value (DRV)	908	(c)	142/232	440-444	142	182.3/254	908	Delivery
Loc Sys Relief value (LSRV)	908	(c)	142/232	440-444	142	182.3/254	908	Delivery
Mkt Transition Credit (MTC)	908		142/232	440-444	142	182.3/254	908	Delivery

Items noted where O&R's reporting treatment may differ from other state utilities:

(a) O&R is proposing to record the portion of the customer credit attributable to the value of environmental RECs to FERC 555 as our existing costs incurred to acquire RECs and ZECs are already being charged to FERC 555 and we would like to maintain consistency with current practice.

(b) O&R is proposing to record the income statement portion of the deferrals related to the value stack components to the same FERC account as is being charged with the customer credits. The rationale for this approach is twofold. First, the existing reconciliation mechanisms in place for some of the components of the value stack (e.g. deferred fuel) are already reconciled to the expense FERC account, so maintaining the current accounting structure eases the administrative burden of this program. Second, for external financial reporting purposes, the company is sensitive to creating revenue through the establishment of regulatory assets; following this accounting will prevent potential FERC to SEC differences with respect to revenue.

(c) O&R is proposing to record the DRV, LSRV, and MTC all to FERC 908. The rationale for this approach is that the company views all of these credits as supporting the efficient and economical use of the utility's service. Additionally, the company anticipates system challenges in billing the delivery charges to multiple FERC accounts.

Appendix B

Appendix B. Proposed Value Stack Tariff Language

The Value Stack Tariff will be applicable to customers served under this Rider that: (1) are not eligible for Grandfathered Net Metering; (2) are not eligible for Phase One NEM; or (3) have made a one-time irrevocable opt-in to the Value Stack Tariff; and (4) are equipped with utility metering capable of recording hourly net consumption and net injections.

Value Stack Tariff Components

1. Energy Component

For any hour in a monthly billing period where there is a net export onto the Company's system by a customer-generator, the customer-generator will receive a credit for energy by multiplying the export in that hour times the Energy Component Rate. These hourly dollar credits will then be summed up in the customer's billing period.

The Energy Component Rate will be equal to the NYISO's day-ahead Locational Based Marginal Price based on the load zone the customer-generator is located in, adjusted for losses.

2. Generating Capacity Component

Customer generators with intermittent generation (*i.e.*, solar and wind electric generating equipment) will choose between Alternative Methods 1, 2, or 3 for their generating capacity credits as follows: Alternative Method 1 is the default methodology for intermittent generation; however, customer generators with intermittent generation can choose Alternative Method 2 or 3; provided that, once chosen, the customer generator cannot switch from Alternative Method 2 to Alternative Method 1 or switch from Alternative Method 3 to either Alternative Methods 1 or 2.

Customer generators with dispatchable generation (*i.e.*, all other electric generating equipment served under this Rider) will be required to receive generating capacity credits under Alternative Method 3.

(a) Alternative Method 1: The Generation Capacity Rate 1 will be the SC 3 capacity rate as shown on a volumetric ($/kWh) basis on the VDER Statement. The credit under Alternative Method 1 will be calculated by multiplying the total net export for the billing period by the customer-generator onto the Company's system by the Generating Capacity Rate 1.

(b) Alternative Method 2: The Generating Capacity Rate 2 will be the capacity rate as shown on the VDER Statement, which is based on the total annual SC 3 capacity costs concentrated into 460 hours occurring during the hours beginning 2 PM through the hours beginning 6 PM during the months of June, July, and August. The credit under Alternative Method 2 will be calculated by multiplying net exports starting at the hour beginning 2 PM through the hour beginning 6 PM in the months of June, July, and August by the Generating Capacity Rate 2 and summing these credits up in the billing period. The Generating Capacity Rate 2 will be zero outside of the months and hours listed above.

(3) Alternative Method 3: The Generating Capacity Rate 3 will be determined by the NYISO ICAP market clearing price applicable in the current billing period and the applicable reserve requirement. The credit under Alternative Method 3 will be calculated by multiplying the NYISO ICAP market clearing price in effect during the current billing period times the applicable reserve requirement times the customer-

generator's energy output during the New York Control Area peak of the previous summer.

3. Environmental Component

The Environmental Component credit will be calculated by multiplying the total net export for the billing period by the customer-generator onto the Company's system by the Environmental Component Rate.

For customers with generation that is eligible to receive Renewable Energy Standard Tier 1 Renewable Energy Credits, customer-generators must choose on the date of interconnection to either retain all RECs generated by the generator, or to sell these RECs to the utility and receive compensation under the Environmental Component Rate. For customer-generators who elect to sell their RECs to the utility, the Environmental Component Rate will be equal to the higher of: (1) the clearing price of the New York State Energy Research and Development's most recent Tier 1 REC procurement at the time of the customer-generator's interconnection; or (2) the Social Cost of Carbon minus the average annual price of a Regional Greenhouse Gas Initiative ("RGGI") carbon dioxide allowance, calculated each January by averaging the clearing price of the previous four RGGI auctions. For all other customers, the Environmental Component Rate is $0/kWh.

The Environmental Component Rate will be fixed for the term of the customer-generator's eligibility for 20 years from the project's in-service date.

4. Demand Reduction Value ("DRV") Component or Market Transition Credit ("MTC") Component

The DRV Component credit will be calculated by multiplying the customer-generator's average hourly output in the ten peak hours of the customer-generator's assigned Commercial System Relief Program ("CSRP") zone in the previous calendar year times the 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, such DRV credit will be multiplied by the percentage of non-Mass Market Satellite Accounts to arrive at the DRV credit.

A CDG Host Account will receive a MTC equal to the MTC SC No. 1 Component Rate applicable to the customer-generator's assigned Tranche times the net export during the billing month times the percentage of SC No. 1 Mass Market Satellite Accounts; plus the MTC SC No. 2 Non-Demand Billed Component Rate times the net export during the billing month times the percentage of SC No. 2 Mass Market Satellite Accounts.

The MTC Rates for SC No. 1 and SC No. 2 will be based on the Tranche into which a customer-generator has been assigned. The DRV Component Rate and MTC Component Rates will be set forth on the VDER Statement.

5. Locational System Relief Value Component

Customers who site their generation 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 LSRV

Component credit will be calculated by multiplying the customer-generator's average hourly output in the ten peak sendout hours in the customer-generator's assigned CSRP zone in the previous calendar year times the LSRV Component Rate in effect. This credit will be calculated annually, divided by twelve, and credited monthly.

The LSRV Component Rate will be set forth on the VDER Statement. The LSRV Component Rate will be fixed for a period of 10 years from the customer-generator's in-service date.

In a billing period, the sum of the above-listed components from (1) to (5) will be added together to arrive at the customer's total credit for the month. The credit will be applied as detailed in the Value Stack Billing Section below.

Value Stack Billing

In a billing period, a customer will be billed for the total consumption of energy measured at the rates specified in the customer's otherwise applicable Service Classification, including applicable demand charges.

If there is a Value Stack credit for the month, such credit will be applied as a direct monetary credit to the customer's current utility bill for any outstanding energy, customer, demand, or other charges. If the customer's current month's Value Stack credit plus any prior period Value Stack credit exceeds the current bill, the remaining monetary credit will be handled as follows:

(1) For Mass Market Customers and Large On-Site Customers, the monetary credit will be carried forward to the succeeding billing period.

(2) For RNM accounts, the remaining monetary credit shall be according to the rules applicable to RNM accounts, as detailed in the RNM and CDG Section of Rider N. For CDG accounts, the remaining monetary credit shall be applied according to the rules applicable to CDG accounts, as detailed in the RNM and CDG Section of Rider N.

Value Stack Account Closure

The Company requires an actual reading to close a Rider N 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, or (b) the date of a special reading, which a customer may request at the charge specified in General Information Section 7.4.

After the final bill is rendered on a Rider N customer's account, including the account of an RNM or CDG Host, any remaining credit on a CDG Host Account 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.

Term

The Term of Service under the tariff for a Value Stack Project is 25 years from the project's in-service date.