

BOARD AGENDA SUMMARY SHEET

Committee or Board: Board	Date: December 4, 2020	Board Meeting Date: December 16, 2020
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For All Board Voting Items:

Title of Agenda Item: Approval of Tariff Changes

Consent Agenda: Yes No

Accompanying Presentation: Yes No

Recommendation from Committee: N/A F&A; GP&P; Oversight & Clean Energy

LIPA Presenter: N/A

PSEG Long Island Presenter: N/A

For Finance Approval Items Only:

Budget ; **Plan of Finance** ; **Tariff Changes** ; **Other** (describe below)

Requested Action:	<p>The Trustees are requested to approve changes to LIPA’s Tariff for Electric Service. The proposed changes will (1) add four residential time-of-use (“TOU”) rates and one small commercial TOU rate; (2) allow for Community Distributed Generation (“CDG”) Net Crediting, which will allow Value Stack CDG satellite customers to receive a single bill from PSEG Long Island; (3) adjust the Revenue Decoupling Mechanism (“RDM”) and the Delivery Service Adjustment (“DSA”) to mitigate future volatility; and (4) implement new provisions of Public Service Law §66-p that allow landlords and prospective tenants to access the historical electric charges billed to a rental property.</p>
Summary: (include proposed amendments to Board Policies, if applicable)	<p>LIPA Staff is proposing to add four TOU Residential Rates and a TOU Small Commercial Rate to the Tariff. Three of the four residential and the single small commercial TOU rates will have three separate daily periods. The daily periods include: (1) peak (2) off-peak and (3) super-off-peak. The proposed three-period TOU rates will also have three pricing seasons: (1) summer (2) spring and fall (shoulder), and (3) winter. The summer peak rate will be the highest in all TOU rates. In addition to seasonal pricing, the rates will have separate pricing for both Energy and Power Supply. Power Supply pricing for each rate will vary each month and appear on the existing Statement of Power Supply Charge. This will encourage customers to shift their energy use outside of the costliest times to produce energy.</p> <p>LIPA Staff is proposing to implement CDG Net Crediting for Value Stack CDG Hosts in accordance with the Net Crediting Order. This program will allow CDG Satellites to receive one bill from LIPA, which will include their CDG-allocated credit, less their CDG Subscription Fee. LIPA will pay the CDG Host the Subscription Fee less a one percent (1%) administrative fee (calculated on the total applied credits of the CDG Host), which is retained by LIPA.</p> <p>LIPA Staff proposes to modify the Tariff for Electric Service to limit the RDM rate to a maximum of 5% of delivery service revenues for any customer class. By implementing a maximum 5% RDM rate for any customer class, LIPA will be able</p>

to mitigate customer bill impacts, which is particularly important during and after events like the COVID-19 pandemic.

LIPA Staff proposes to modify the Tariff to allow for potential lessee, potential tenant, or the current landlord to request, in writing, the total electric charges monthly or bi-monthly incurred by the property for the prior two years. This information will be provided via e-mail to the requesting party free of charge.

FOR CONSIDERATION

December 16, 2020

TO: The Board of Trustees
FROM: Thomas Falcone
SUBJECT: Approval of Tariff Changes

Requested Action

The Trustees are requested to approve changes to LIPA's Tariff for Electric Service. The proposed changes will (1) add four residential time-of-use ("TOU") rates and one small commercial TOU rate; (2) allow for Community Distributed Generation ("CDG") Net Crediting, which will allow Value Stack CDG satellite customers to receive a single bill from PSEG Long Island; (3) adjust the Revenue Decoupling Mechanism ("RDM") and the Delivery Service Adjustment ("DSA") to mitigate future volatility; and (4) implement new provisions of Public Service Law §66-p that allow landlords and prospective tenants to access the historical electric charges billed to a rental property.

Time of Use Rates: Background

In recent years, LIPA and PSEG Long Island have undertaken a rate modernization initiative with the objectives of offering customers rate options that are simple to understand, easy to compare, and that promote efficient use of the electric grid. PSEG Long Island has also launched a service-territory-wide deployment of advanced metering infrastructure ("AMI") smart meters, which enable the functionality required for rate modernization.

In its 2018 Utility 2.0 Plan and subsequent updates, PSEG Long Island presented plans to modernize the customer experience by offering tools and rate options that encourage customers to proactively manage their energy use and lower their costs. The 2018 Utility 2.0 Plan proposed four new residential time-of-use rate options. Three of the proposed rate options feature three separately priced time periods. Consistent with industry best practices, the three periods consist of a three-hour or four-hour peak¹ rate, an off-peak rate and a super-off-peak rate. These rate periods will give the customer the opportunity to reduce or shift demand more easily and manage their usage outside of the peak timeframe. The filing also presented a two-period residential rate design, which is primarily for customers who own or lease an electric vehicle that can be charged overnight yet prefer a flat rate structure during the daytime.

In addition, the 2018 Utility 2.0 filing presented plans for a Small Business Short Peak TOU Rate. The design of this rate includes a short four-hour peak period² that may benefit small business customers who can limit their energy use during a few higher cost weekday hours and shift usage to other off-peak periods, including customers that can be flexible about when they use major business appliances, such as air conditioners, electric forklifts, or other large demand machines.

¹ LIPA's legacy TOU rates have on-peak windows ranging from eight to twelve hours.

² The current peak period spans daytime for a full 10 hours.

The 2018 Utility 2.0 Plan’s rate modernization initiative was recommended by the Department of Public Service (“DPS”) and approved by the LIPA Board of Trustees. Since that time, PSEG Long Island has conducted additional customer focus groups and reviewed TOU research from around the country, conferring with utilities experienced in smart meter enabled time-of-use rates to learn best practices. These focus groups and related research, along with our specific requirements for system operations, have informed the parameters of the rate designs in this proposal.

In addition to giving customers more options and control of their energy use, these rates will also help in reducing the peak load of the utility. By giving customers the ability to shift their load to more affordable times of the day, PSEG Long Island can decrease the amount of energy production during peak times of the day. Additionally, this will help reduce carbon emission and could possibly reduce the need for new capital expenditures as customers reduce the capacity needs on certain circuits.

Time of Use Rates: Proposed Action

LIPA Staff is proposing to add four TOU Residential Rates and a TOU Small Commercial Rate to the Tariff.

Three of the four residential and the single small commercial TOU rates will have three separate daily periods. The daily periods include: (1) peak (2) off-peak and (3) super-off-peak. The proposed three-period TOU rates will also have three pricing seasons: (1) summer (2) spring and fall (shoulder), and (3) winter. The summer peak rate will be the highest in all TOU rates. In addition to seasonal pricing, the rates will have separate pricing for both Energy and Power Supply. Power Supply pricing for each rate will vary each month and appear on the existing Statement of Power Supply Charge. This will encourage customers to shift their energy use outside of the costliest times to produce energy.

The fourth residential TOU rate will have two daily periods: (1) daytime and (2) nighttime. Electric vehicle customers who prefer a flat rate during the daytime will be encouraged to use this rate.

Residential Three-Hour Peak (Rate Code 190: Short Peak)

This TOU rate design has a short three-hour peak from 4 PM to 7 PM and a super-off-peak from 10 PM to 6 AM. This design benefits customers who can shift their energy use away from the three-hour peak and allows them to take advantage of the super-off-peak pricing during the early morning hours of the day. During the summer period, when the rates have the largest variability, the peak-period rate is set to about 2.15 times the off-peak rate, and the super-off-peak rate will be about 0.6 times the off-peak rate.

Residential Four-Hour Peak (Rate Code 191: Late Peak)

This TOU rate design has a four-hour peak from 4 PM to 8 PM and a super-off-peak from 11 PM to 7 AM. This design benefits customers who can shift their energy use for a slightly longer amount of time during the day and allows them to take advantage of the super-off-peak pricing during the early morning hours of the day. During the summer period, when the rates have the largest variability, the peak-period rate is set to about 1.84 times the off-peak rate, and the super-off-peak rate will be about 0.6 times the off-peak rate.

Residential Four-Hour Peak (Rate Code 192: Early Peak)

This TOU rate design has a four-hour peak from 3 PM to 7 PM and a super-off-peak from 10 PM to 6 AM. It is similar to Rate Code 191 but starts and ends one hour earlier. Customers will experience savings when they shift their energy use to the evening as this TOU rate has the earliest super-off-peak time. During the summer period, when the rates have the largest variability, the peak-period rate is set to about 1.89 times the standard rate, and the super-off-peak rate will be about 0.6 times the off-peak rate.

Day/Night (Rate Code 193: Overnight)

The Day/Night TOU rate has two periods in each day. This will give customers who are interested in cost savings the opportunity to shift some of their energy use to the overnight hours without being subject to a higher peak rate during the day. The Daytime rate has a smaller ratio of only 1.12 times the standard rate for peak and the Nighttime rate will be about 0.6 times the standard rate. There are two seasons proposed for this rate option: summer and winter/shoulder season.

Small Business (Rate Code 292: 4 Hour Peak Small)

The Small Business TOU Rate has a shorter peak period than has been offered in the past. The Small Business peak period will be from 3 PM to 7 PM and a super-off peak from 11PM to 6AM. It has a four-hour peak as compared to existing time-of-use rates that have a longer 10-hour peak period from 10 AM to 8 PM. This rate allows customers to shift energy use for a shorter length of time. During the summer period, when the rates have the largest variability, the peak rate is set to about 1.8 times the off-peak rate, and the super-off-peak rate will be about 0.6 times the off-peak rate.

Power Supply Charge

The proposed new rates will time differentiate both the Delivery Service Charge and the Power Supply Charge. The Power Supply Charge will be time-differentiated for each of the proposed new rate codes using a multiplier against the standard non-time-differentiated Power Supply Charge. In each month as the Power Supply Charge gets updated, that single cents per kWh charge will be multiplied by the same factors applied to delivery rates (described above), to create the time-differentiated charges for the peak and off-peak periods. The factors were calculated to recover the same annual total power supply costs that would be recovered through standard rates.

Other Tariff Changes Related to TOU Proposal

LIPA Staff proposes to close older, less effective TOU rates in Service Classification No. 1 – VMRP (L) and Service Classification No. 1 – VMRP (S) on January 1, 2025, with the exception of rate code 182, a TOU rate for space heating customers, which will be closed on January 1, 2025 or one year after the effective date of a new, yet-to-be-proposed space heating TOU rate

(whichever is later). Customers still on these rates will be encouraged to transition to proposed Service Classification No. 1 – VTOU.

LIPA Staff also proposed to discontinue new customer enrollments in the existing off-peak energy storage rates (rate codes 480 and 481) on January 1, 2021 and to discontinue these rate codes on January 1, 2025. The proposed TOU rates with a ratio of 0.6 times the standard rate during the super-off-peak period will be more beneficial to customers seeking to charge energy storage systems overnight. Customers who are currently on rates 480 and 481 will be able to remain on these rates through the end of 2024, at which time they will be encouraged to transfer to any of the newly proposed TOU rate codes.

The new TOU rates will require clarification and additional detail regarding Net Metering banking rules. LIPA Staff proposes to add rules to the Net Metering tariff, such that a customer who switches from a rate with one rate period to a rate with multiple rate periods will transfer all billing credits to the off peak period, as this is set to equal the standard rate. Also, to allow the Tariff to address the reverse situation, customers who move from multiple rate periods to one rate period will have all credits consolidated to the standard rate bank.

Finally, LIPA Staff is proposing to designate the Federal Holidays that will be used to determine off peak days. LIPA has reviewed the various uses of “holiday” in the Tariff and determined that Federal Holiday, Public Holiday and PSEG Long Island Holiday are all terms that need to be defined in the glossary and appropriately amended in the Tariff.

Community Distributed Generation Net Crediting: Background

On July 17, 2015³ and October 16, 2015⁴ the New York Public Service Commission (“PSC” or “Commission”) issued Orders in Case 15-E-0082 setting forth policies, requirements and conditions for implementation of CDG by New York’s investor-owned utilities.⁵ The CDG Program has three main entities: the CDG Host; CDG Satellites; and the utility. A CDG Host is the project sponsor and is responsible for owning or operating the generation facility, coordinating the project’s interconnection and operation with the utility, and signing up the project’s satellites. CDG Satellites are the project subscribers, and customers of the utility.

Currently, each CDG Satellite customer of a Value Stack compensated CDG project receives a credit on its electric bill for its proportionate share of the Value Stack credits generated by the CDG Host, and the CDG Host separately bills each satellite for its subscription fee.

On December 12, 2019, the Commission issued its Order Regarding Consolidated Billing for Community Distributed Generation in Case 19-M-0463 (Net Crediting Order) which established

³ 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 Establishing a Community Distributed Generation Program and Making Other Findings*; Issued and effective July 17, 2015

⁴ 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 Granting Reconsideration in Part*; Issued and effective July 16, 2015

⁵ Although LIPA is not subject to the PSC’s orders, LIPA implemented CDG on similar terms.

the policies, requirements and conditions to implement net crediting⁶. Under the net crediting framework, CDG Satellites who subscribe to a CDG Host that has elected the net crediting option will receive credits on their utility bills based on the generation facility's meter, as a percentage of the generation facility's output in excess of usage on the CDG Host's account. The utility is responsible for distributing the credits from the CDG Host's account on satellite customers' bills in accordance with the CDG sponsor's instructions. The subscription fees are deducted from the credits and sent by the utility to the CDG Host, based on a percentage set by the CDG Host, less a 1% fee retained by the utility to cover its costs of administering the program.

Community Distributed Generation Net Crediting: Proposed Action

LIPA Staff is proposing to implement CDG Net Crediting for Value Stack CDG Hosts in accordance with the Net Crediting Order. This program will allow CDG Satellites to receive one bill from LIPA, which will include their CDG-allocated credit, less their CDG Subscription Fee. LIPA will pay the CDG Host the Subscription Fee less a one percent (1%) administrative fee (calculated on the total applied credits of the CDG Host), which is retained by LIPA.

CDG Hosts will be able to sign up for the net crediting program so long as all Satellites are compensated under Value Stack Crediting. All Satellites, with the exception of one Anchor Satellite (described below), will be required to have the same CDG Savings Rate, which is the percentage of savings the customer will retain. The CDG Savings Rate must be a minimum of 5% of the Value Stack Credit.⁷

A CDG Satellite's Applied Credit will be calculated for each billing period, pursuant to the CDG Net Crediting Tariff, and equals the portion of the Total Available Credit that offsets the CDG Satellite's Electric Bill in the billing period. A CDG Satellite's Applied Credit cannot exceed the amount of a CDG Satellite's Electric Bill during an individual billing period. The Authority shall use the Applied Credit as the basis to determine the CDG Subscription Fee. The Authority will provide each CDG Satellite with the net credit on the CDG Satellite's Electric Bill.

The CDG Host can exclude one Anchor Satellite from the program. An Anchor Satellite is a large commercial customer that "anchors" the project by taking a significant share of the output of the Host facility (not to exceed 40%) and paying a significant share of the costs for that facility directly to the CDG Host. LIPA will multiply the total Value Stack Credit of the CDG Host times the percentage allocated to the Anchor Satellite (not to exceed 40%) and include that amount of credit to the Anchor Satellite's account in the month. The CDG Host would separately bill the Anchor Satellite for any subscription fees applicable to that Anchor satellite according to their separate agreement.

A CDG Subscription Fee will be calculated based each CDG Satellite's Applied Credit in each billing period. The CDG Subscription Fee is equal to the amount of the Applied Credit multiplied by a percentage equal to one minus the CDG Savings Rate. (e.g. if the savings rate is 5% the CDG Subscription Fee will equal 1 minus .05, or 95%). Payments will be made to the CDG Host from LIPA for the total Subscription Fee of the satellites in the project, less a one percent (1%)

⁶ Case 19-M-0463, *In the Matter of Consolidated Billing for Distributed Energy Resources., Order Regarding Consolidated Billing for Community Distributed Generation*; Issued and effective December 12, 2019

⁷ 5 percent minimum is calculated based on the Value Stack Credit amount per kWh.

administrative fee that is retained by LIPA. The proposed 1% fee was approved by the Commission for the regulated investor-owned utilities in the State.

Revenue Decoupling Mechanism and Delivery Service Adjustment: Background

LIPA implemented a Revenue Decoupling Mechanism (“RDM”) on April 1, 2015. The use of an RDM is consistent with PSC policy. It helps to achieve financial stability without the conflicting pressures created by the pursuit of energy efficiency and renewable goals that reduce electric sales and corresponding revenues until base rates are reset in the future. An RDM is designed to ensure that a distribution utility collects only its approved revenues for delivery service from customers: excess recoveries are refunded to customers and insufficient recoveries are collected in the following period.

LIPA’s customers have suffered financial hardship during the COVID-19 pandemic. During 2020, in response to the COVID-19 pandemic and resulting New York State emergency declaration, the LIPA Board of Trustees approved several relief measures for customers, including suspending late payment charges and easing terms for deferred payment agreements. The proposed change to LIPA’s RDM will complement these previously approved measures by smoothing RDM recoveries, limiting the potential impact of the RDM on customers in any particular year. It is important to put this change into effect now, to help customers beginning in 2021. Many small business customers had to suspend operations, experiencing lost revenues. This has also resulted in lower electricity sales to LIPA’s small business customer classes. Under LIPA’s existing RDM Tariff rules (absent this proposal), the full amount of this revenue loss would be recovered from these classes in 2021.

The Delivery Service Adjustment (“DSA”) is a rate mechanism to reconcile certain budgeted costs, which are based on projections, to actual accrued costs after the end of each year. The DSA ensures that customers pay only the actual costs incurred to provide service in these specified cost categories rather than the projections of these costs established during LIPA’s budgeting process. The cost categories subject to these updates and reconciliations currently include debt service costs (for variances in interest rates, capital expenditures, and bond refinancing savings), and storm restoration costs. Each of these specified costs vary based on factors largely outside of the control of the utility, so reconciliation is important to ensure that customers pay only the actual costs incurred. The proposal will add three other cost categories to the DSA for reconciliation: non-storm emergency events, bad debt expense, and pension and other post-employment benefit (“OPEB”) expenses.

Non-storm emergency events are defined in the Amended and Restated Operating Services Agreement (“OSA”) as emergencies (other than storms) that are beyond the reasonable control of PSEG Long Island and not already budgeted.

Bad debt expenses are arrearages that, in the estimation of the LIPA’s financial auditors, are not likely to be recovered and need to be written off the Authority’s audited financial statements. Under the proposal, the DSA will reconcile the budgeted estimate of bad debt expense to the amount actually accrued during the year (if higher or lower than budgeted).

Pension and Other Post-Employment Benefits (“OPEB”) expenses ensure that LIPA will be able

to meet its contractual obligations in the future to provide benefits, such as pensions and health care, to retired employees of PSEG Long Island. These expenses are difficult to forecast in advance and vary significantly as a result of factors that are outside the control of the utility, such as market interest rates and medical cost inflation. The DSA will reconcile the O&M budget estimates of pension and OPEBs (which are estimated by an actuary around August of the prior year) to the amount actually accrued during the year. The PSC has recognized that pension and OPEB obligations are subject to volatility and has provided reconciliation mechanisms for the regulated electric utilities in the State.

Revenue Decoupling Mechanism and Delivery Service Adjustment: Proposed Action

LIPA Staff proposes to modify the Tariff for Electric Service to limit the RDM rate to a maximum of 5% of delivery service revenues for any customer class. By implementing a maximum 5% RDM rate for any customer class, LIPA will be able to mitigate customer bill impacts, which is particularly important during and after events like the COVID-19 pandemic.

As a further mitigation measure, to the extent a revenue loss is caused by a decrease in customers of more than 5% in any commercial rate class, (as opposed to reduced consumption by customers who remain on the system), then the portion of the revenue variance caused by the decrease in customers will be allocated among all commercial rate classes. This provision will prevent remaining customers from being charged a disproportionately higher RDM rate if the size of their customer class decreases.

With respect to the DSA, LIPA Staff proposes to amend the DSA to include incremental expenditures related to Non-Storm Emergencies, as defined in the OSA, net of any anticipated reimbursements from outside sources (such as the Federal Emergency Management Administration) during a non-storm emergency event or condition. Should anticipated reimbursements not come to fruition they will be added to subsequent tracking periods. Costs will be included in the DSA only if a budget amendment is requested by PSEG Long Island pursuant to the OSA, determined by LIPA Staff to be a material adjustment, and approved by the LIPA Board. DPS Staff would also review and confirm the validity of such expenses, as they currently do for storm costs.

The proposed DSA amendments will also reconcile any variance of accrued bad debt expense from the budgeted amount during periods affected by a government ordered or Board authorized moratorium on service disconnections and for up to two years following the end of such moratorium. Because this provision is only applicable for up to two years following a moratorium on service disconnections (a rare event), this provision will apply only after highly unusual events, such as the COVID-19 pandemic.

The DSA proposal will also reconcile variations in expenditures related to pensions and OPEBs from the estimated amounts included in the annual budget. At the end of each calendar year, the actual audited cost of pensions and OPEBs recognized as operating expense will be compared to the amount approved by the Board in the annual budget and the variance will be included in the DSA for recovery or refund in the following year. Any OPEB expenses recovered through the DSA will be contributed to the OPEB trust account, to meet future obligations to retired employees. To the extent that the OPEB expense recovered through the DSA is negative, the

annual contribution to the OPEB account will be reduced by that same amount.

The proposal to reconcile these costs in the DSA benefits all LIPA customers because it allows LIPA to provide service at the lowest possible cost. Without a true-up mechanism like the DSA, LIPA would need to set higher budgets for these items, or incur higher borrowing costs, which would result in correspondingly higher customer rates.

Rental Property Data Access: Background

On April 18, 2020, Section 66-p of Public Service Law (PSL) became effective requiring that every electric corporation, gas corporation, and municipality provide a landlord or lessor of a residential rental premises historical billing information within ten days of a written request.

Rental Property Data Access: Proposed Action

LIPA Staff proposes to modify the Tariff to allow for potential lessee, potential tenant, or the current landlord to request, in writing, the total electric charges monthly or bi-monthly incurred by the property for the prior two years. This information will be provided via e-mail to the requesting party free of charge.

Financial Impacts

The TOU rate proposal is not expected to result in material revenue impacts. Revenue variances, if any, will be recovered in the Revenue Decoupling Mechanism. The financial impact of the proposal on any particular customer will depend on the customer's ability and willingness to reduce usage during the peak period. PSEG Long Island estimates that a typical customer who shifts 10% of peak usage would save between \$60 and \$70 annually. Energy cost savings from the avoidance of high cost generation during the peak hours would reduce the net financial impact to LIPA. The cost of implementing the billing system add-on to enable the TOU rate options was approved in prior year's Utility 2.0 filings. The total expenditures incurred through 2020 are \$5.3 million in capital and \$1.9 million in operating expenses. All expenditures were recommended by the DPS and approved by the LIPA Board of Trustees.

The CDG net crediting proposal has no anticipated financial impact to LIPA, as LIPA's costs of administering the program will be compensated through the one percent (1%) Administrative Fee.

The RDM proposal will have no long-term financial impact to LIPA. Revenues that would have been collected through the current year's RDM but for the 5% cap will either be deferred to future years or be shared among other classes in the same year. Customers may benefit from the cap in the year it is applied, as this will reduce their current year's bill impacts. Over the long term, the proposal is largely revenue neutral within any particular customer class because revenues in excess of the cap will be recovered from the same class in subsequent periods, with the exception noted above that revenue variances caused by decreases in the size of a commercial class will be allocated to all commercial classes.

The proposed changes to the DSA do not have any known financial impact because budgets for each of the included cost components are estimated based on the best available information. To the extent the budget amounts for bad debt expense, pensions or OPEBs differ from actual accrued costs, the variance will be recovered or refunded in the DSA.

The proposal to provide billing information regarding rental properties, assuming 100 requests per month, is estimated to have an annual financial impact to LIPA of approximately \$24,000, or \$20 per request. The actual financial impact will depend on the number of requests received.

Department of Public Service Input

The DPS has provided a letter recommending adopting of these tariff modifications, which is attached as an exhibit. The final proposed tariffs incorporate the DPS's recommendations. The DPS also provided feedback and input throughout the process of developing the tariffs, which was reflected in the original proposals.

Public Comments

LIPA held virtual public comment sessions on the proposed tariff changes on November 18th and November 19th and also solicited written comments. Transcripts of the virtual public comment sessions and copies of the written comments are attached and the comments are summarized here, together with responses from LIPA Staff.

NineDot Energy, a DER provider, submitted written comments in support of the proposed TOU rate options and the CDG net crediting proposal and additional recommendations regarding those proposals. NineDot specifically noted its support of the proposed time-differentiation of LIPA's Power Supply Charge for customers on the new TOU rates. NineDot also urged LIPA to adopt a time-differentiated Power Supply Charge for its existing large commercial TOU rates, commenting that such a change would enable more widespread adoption of energy storage. Regarding the CDG net crediting proposal, NineDot offered three suggestions: first, that CDG Hosts should be able to set different Savings Rates for each customer; second, that a CDG Host electing net crediting should more be able to select more than one large anchor customer who would not be subject to consolidated billing; and third, that LIPA should also adopt a remote net crediting model allowing up to ten customers to receive remote net metering credits from a single project.

Response: The five new TOU rate pilots in the proposed today are just the beginning of a phased, smart-meter-enabled rate modernization plan, originally proposed in PSEG Long Island's 2018 Utility 2.0 Plan. Subsequent phases will include time-differentiated power supply rates for large commercial customers, subject to approval by the LIPA Board.

LIPA's CDG net crediting proposal is closely aligned with the net crediting policy of the PSC, including with respect to the three suggestions offered by NineDot, which are not currently available at the State's investor-owned utilities to our knowledge. Additionally, PSEG Long Island does not have billing system capabilities at present to allow for different Savings Rates for each customer or remote net crediting. However, LIPA and PSEG Long Island Staff are monitoring the PSC proceedings on this topic and will recommend to the

LIPA Board that LIPA's net crediting rules and billing system capabilities should evolve as needed to align with PSC policy on this matter.

The Deputy Supervisor of the Town of Southampton submitted comments in support of the CDG net crediting proposal and related recommendations. The Deputy Supervisor recommends that CDG Net Crediting Agreements between LIPA and CDG Hosts (which are related to the proposal but not part of LIPA's Tariff) should not require the CDG Hosts to indemnify the utility for losses caused by the utility's own negligence. The Deputy Supervisor also made recommendations regarding the Data Security Agreements applicable to administrators of Community Choice Aggregation ("CCA"). Finally, the Deputy Supervisor recommended that CDG Net Crediting be made available to net metered subscribers of CDG projects.

Joule Assets, a CCA Administrator to the Town of Southampton, submitted comments on the CDG net crediting proposal including the same recommendations made by the Deputy Administrator. Joule Assets also included several recommendations regarding LIPA's Long Island Choice Tariff.

Response: LIPA expects to offer CDG Hosts a Net Crediting Agreement that does not require CDG Hosts to indemnify LIPA for losses caused by its own gross negligence or willful misconduct. To our knowledge, these indemnification terms are identical to those offered by the rest of the State's utilities to CDG Hosts. The Net Crediting Agreement LIPA offers will also have data security provisions similar to those offered by other utilities in the State. Although not the subject of these Tariff proposals, LIPA notes that it is working with the DPS to develop a suitable form Data Security Agreement for CCAs that is consistent with PSC policy on data security for CCAs. Regarding the recommendation that net crediting be extended to Hosts of net metered CDG projects, LIPA Staff responds that it is monitoring the PSC proceedings on this topic and will recommend to the LIPA Board that LIPA's net crediting rules and billing system capabilities should evolve as needed to align with PSC policy on this matter. Finally, regarding Joule Assets' comments on Long Island Choice, LIPA notes that a separate DPS collaborative proceeding has been commenced to address potential improvements to Long Island Choice and suggests that Joule Assets submit its comments for consideration in that proceeding, which we expect will result in a recommendation to the LIPA Board.

FourGen LLC submitted comments in support of the CDG net crediting tariff proposal and recommending that net crediting be extended to Hosts of net metered CDG projects in addition to those compensated under the Value Stack.

Response: LIPA Staff is monitoring the PSC proceedings on this topic and will recommend to the LIPA Board that LIPA's net crediting rules and billing system capabilities should evolve as needed to align with PSC policy on this matter.

PowerMarket, a company that manages CDG projects on behalf of CDG Hosts, submitted comments recommending improvements to PSEG Long Island's approach for applying volumetric credits to the Satellite customers of net metered CDG projects. Specifically, PowerMarket notes that PSEG Long Island's bills to these Satellite customers reflect only the customer's net kWh usage, without any indication of either the quantity of kWh credits applied to the bill from the CDG project or the monetary value of the credits applied. According to PowerMarket, this impedes the

ability of CDG Hosts to handle inquiries from Satellite customers and to substantiate the subscription fees charged by CDG Hosts to their Satellites, threatening the success of LIPA and PSEG Long Island's CDG program.

Response: LIPA Staff agrees with the comment and recommends that the LIPA Board direct PSEG Long Island to modify its billing of net metered CDG Satellites to reflect the quantity of kWh credits applied in each billing period and the monetary value of those credits.

Recommendation:

For the foregoing reasons, I recommend that the Trustees approve the modifications to the Tariff for Electric Service described herein and set forth in the accompanying resolutions.

Attachments

- Exhibit A-1** Resolution Approving Time-of-Use Rate Tariff Changes
- Exhibit A-2** Resolution Approving Community Distributed Generation Net Crediting Tariff Changes
- Exhibit A-3** Resolution Approving Revenue Decoupling Mechanism and Delivery Service Adjustment Tariff Changes
- Exhibit A-4** Resolution Approving Rental Property Data Access Changes
- Exhibit B-1** Time-of-Use Tariff Redline (final proposed tariff compared to current tariff)
- Exhibit B-2** Community Distributed Generation Net Crediting Tariff Redline (final proposed tariff compared to current tariff)
- Exhibit B-3** Revenue Decoupling Mechanism and Delivery Service Adjustment Tariff Redline (final proposed tariff compared to current tariff)
- Exhibit B-4** Rental Property Data Access Redline (final proposed tariff compared to current tariff)
- Exhibit C** DPS Letter of Recommendation
- Exhibit D** Public Comment Session Transcripts
- Exhibit E** Compendium of Written Public Comments Received

Please note that the Tariff redlines attached as Exhibits B-1 to B-4 show the final proposed Tariff language, reflecting feedback from the Department of Public Service. The original Tariff proposals are available on LIPA's Proposed Rulemaking webpage until January 1, 2021 (at <https://www.lipower.org/about-us/tariff/proposed-rulemaking/>).

APPROVAL OF MODIFICATIONS TO LIPA'S TARIFF RELATED TO TIME-OF-USE RATES

WHEREAS, the Board of Trustees of the Long Island Power Authority ("LIPA") has adopted a Board Policy on Customer Value and Affordability, which sets forth the Board's commitment to establishing rates that are generally comparable to similarly situated regional utilities and New York Public Service Commission policy; and

WHEREAS, the proposal is consistent with the Board Policy on Customer Value and Affordability; and

WHEREAS, the Department of Public Service is supportive of this proposal; and

WHEREAS, following the issuance of public notice in the State Register on September 16, 2020, public hearings were held on November 18 and 19, 2020, by phone and video conference accessible to participants in Nassau and Suffolk County, and the public comment period has since expired;

NOW, THEREFORE, BE IT RESOLVED, that for the reasons set forth herein and in the accompanying Memorandum, the proposed modifications to LIPA's Tariff are hereby adopted and approved to be effective February 1, 2021; and be it further

RESOLVED, that the Chief Executive Officer and his designees are authorized to carry out all actions deemed necessary or convenient to implement this Tariff; and be it further

RESOLVED, that the Tariff amendments reflected in the attached redlined Tariff leaves are approved.

Dated: December 16, 2020

**APPROVAL OF MODIFICATIONS TO LIPA'S TARIFF RELATED TO
COMMUNITY DISTRIBUTED GENERATION NET CREDITING**

WHEREAS, the Board of Trustees of the Long Island Power Authority (“LIPA”) has adopted a Board Policy on Resource Planning, Energy Efficiency and Renewable Energy, which sets forth the Board’s commitment to integrating cost-effective distributed energy production and storage technologies into the Authority’s electric transmission and distributions system, and enabling the economic and secure dispatch of resources deployed within the distribution system and within customer premises (the “Board Policy on Resource Planning”); and

WHEREAS, the Board of Trustees of the Long Island Power Authority (“LIPA”) has adopted a Board Policy on Customer Value and Affordability, which sets forth the Board’s commitment to establishing rates that are generally comparable to similarly situated regional utilities and New York Public Service Commission policy; and

WHEREAS, the Board of Trustees of the Long Island Power Authority (“LIPA”) has reviewed the proposal and determined that it is consistent with the mission and values of the Authority as set forth in the Board’s policy statements, including the Board Policy on Resource Planning and the Board Policy on Customer Value and Affordability; and

WHEREAS, the Department of Public Service is supportive of this proposal; and

WHEREAS, following the issuance of public notice in the State Register on September 16, 2020, public hearings were held on November 18 and 19, 2020, by phone and video conference accessible to participants in Nassau and Suffolk County, and the public comment period has since expired;

NOW, THEREFORE, BE IT RESOLVED, that for the reasons set forth herein and in the accompanying Memorandum, the proposed modifications to LIPA’s Tariff are hereby adopted and approved to be effective January 1, 2021; and be it further

RESOLVED, that the Chief Executive Officer and his designees are authorized to carry out all actions deemed necessary or convenient to implement this Tariff; and be it further

RESOLVED, that the Tariff amendments reflected in the attached redlined Tariff leaves are approved.

Dated: December 16, 2020

APPROVAL OF MODIFICATIONS TO LIPA’S TARIFF RELATED TO THE REVENUE DECOUPLING MECHANISM AND DELIVERY SERVICE ADJUSTMENT

WHEREAS, the Board of Trustees of the Long Island Power Authority (“LIPA”) has adopted a Board Policy on Customer Value and Affordability, which sets forth the Board’s commitment to establishing rates that are comparable to similarly situated regional utilities and consistent with New York Public Service Commission policy; and

WHEREAS, the proposal is consistent with the Board Policy on Customer Value and Affordability; and

WHEREAS, the Department of Public Service is supportive of this proposal; and

WHEREAS, following the issuance of public notice in the State Register on September 16, public hearings were held on November 18 and 19, 2020, by phone and video conference accessible to participants in Nassau and Suffolk County, and the public comment period has since expired;

NOW, THEREFORE, BE IT RESOLVED, that for the reasons set forth herein and in the accompanying Memorandum, the proposed modifications to LIPA’s Tariff are hereby adopted and approved to be effective January 1, 2021; and be it further

RESOLVED, that the Chief Executive Officer and his designees are authorized to carry out all actions deemed necessary or convenient to implement this Tariff; and be it further

RESOLVED, that the Tariff amendments reflected in the attached redlined Tariff leaves are approved.

Dated: December 16, 2020

APPROVAL OF MODIFICATIONS TO RENTAL PROPERTY DATA ACCESS

WHEREAS, the Board of Trustees of the Long Island Power Authority (“LIPA”) has reviewed the proposal and determined that it is consistent with the mission and values of the Authority as set forth in the Board’s policy statements; and

WHEREAS, the Department of Public Service is supportive of this proposal; and

WHEREAS, following the issuance of public notice in the State Register on September 16, 2020, public hearings were held on November 18 and 19, 2020, by phone and video conference accessible to participants in Nassau and Suffolk County, and the public comment period has since expired;

NOW, THEREFORE, BE IT RESOLVED, that for the reasons set forth herein and in the accompanying Memorandum, the proposed modifications to the LIPA’s Tariff are hereby adopted and approved to be effective January 1, 2021; and be it further

RESOLVED, that the Chief Executive Officer and his designees are authorized to carry out all actions deemed necessary or convenient to implement this Tariff; and be it further

RESOLVED, that the Tariff amendments reflected in the attached redlined Tariff leaves are approved.

Dated: December 16, 2020

Exhibit B-1 - Time-of-Use Tariff Redline

I. General Information (continued):**B. Abbreviations and Definitions (continued):**

Demand Customer: A Customer who is billed for Demand charges.

Demand Meter: The device that records the maximum amount of power used by the Customer over a 15-minute interval during a specific period, such as a month.

Department: The New York State Department of Public Service.

Deposit: A sum of money given as security for payment of service.

Distribution Facilities: Facilities used to distribute electric energy to consumers, including supply lines, distribution lines, service laterals, and accessory equipment.

Distribution Line(s): A system of poles, wires, ducts, conduits, and additional equipment used for the shared distribution of electricity to Customers.

E

Easement: (See *Right-of-way*)

Eligible Net Metering Technology/Technologies: The list of eligible technologies is: Solar Electric Generating Equipment, Wind Electric Generating Equipment, Micro-Hydroelectric Generating Equipment, Micro-Combined Heat and Power (CHP) Generating Equipment, Fuel Cell Electric Generating Equipment, Farm Waste Electric Generating Equipment, Stand Alone Storage Equipment, Regenerative Braking, Vehicle-to-Grid, or other generating equipment identified as a Tier 1 technology as defined in Appendix A of the CES Order of the New York Public Service Commission issued August 1, 2016 in Cases 15-E-0302 and 16-E-0270. Regenerative braking, vehicle to grid, and additional Tier 1 technologies identified in Appendix A of the CES Order but not specifically defined in this tariff, and any other technologies not defined by PSL §66-p as renewable energy systems are required to take compensation based on the Value Stack.

Energy: Energy is electric power, used or supplied over time, and measured in KWH.

Existing Overhead Areas: Areas in which electric distribution facilities are constructed overhead, and there are no requirements to construct facilities underground.

F

Farm Waste Electric Generating Equipment: Equipment that generates electric energy from biogas produced by anaerobic digestion of agricultural wastes, such as livestock manure, farming wastes and food processing wastes with a rated capacity of not more than five thousand (5,000) kilowatts that is manufactured, installed and operated by Customer-generator in accordance with applicable government and industry standards, connected to the electric system and operated in conjunction with the Authority's transmission and distribution facilities, operated in compliance with the Authority's standards and requirements established therefor, fueled at a minimum of ninety (90) percent on an annual basis by biogas produced from the anaerobic digestion of agricultural waste such as livestock manure materials, crop residues, and food processing waste, and fueled by biogas generated by anaerobic digestion with at least fifty (50) percent by weight of its feed stock being livestock manure on an annual basis. As of October 17, 2019, all new projects with Farm Waste Electric Generating Equipment are not considered a renewable energy system as defined by PSL §66-p.

~~**Fuel Cell Electric Generating Equipment:** A solid oxide, molten carbonate, proton exchange membrane or phosphoric acid fuel cell, with a combined rated capacity of not more than ten (10) kilowatts for a residential customer or with a rated capacity of not more than five thousand (5,000) kilowatts for a non-residential customer, that is manufactured, installed and operated in accordance with applicable government and industry standards, that is connected to the electric system and operated in compliance with the Authority's standards and requirements established therefor. This definition, including the capacity limits specified herein, does not apply to fuel cells participating in the Fuel Cell Feed-in Tariff. As of October 17, 2019, all new projects with Fuel Cell Generating~~

~~Equipment which utilize a fossil fuel resource in the process of generation are not considered a renewable energy system as defined by PSL §66-p.~~

~~**Fuel and Purchased Power Cost Adjustment Clause:** See definition for Power Supply Charge.~~

~~**Full Requirements Customer:** A Customer whose electric power requirements are all supplied by the Authority. (See *Customer* — *Full Requirements Customer*)~~

~~**G**~~

~~**Generation Project:** A specific project that is eligible to participate in the Commercial Solar, Fuel Cell, or Solar Communities Feed In Tariffs under Service Classification No. 11 — Buy Back Service.~~

I. General Information (continued):**B. Abbreviations and Definitions (continued):**

Federal Holidays: New Year's Day, Martin Luther King, Jr. Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, and Christmas Day

Fuel Cell Electric Generating Equipment: A solid oxide, molten carbonate, proton exchange membrane or phosphoric acid fuel cell, with a combined rated capacity of not more than ten (10) kilowatts for a residential customer or with a rated capacity of not more than five thousand (5,000) kilowatts for a non-residential customer, that is manufactured, installed and operated in accordance with applicable government and industry standards, that is connected to the electric system and operated in compliance with the Authority's standards and requirements established therefor. This definition, including the capacity limits specified herein, does not apply to fuel cells participating in the Fuel Cell Feed-in Tariff. As of October 17, 2019, all new projects with Fuel Cell Generating Equipment which utilize a fossil fuel resource in the process of generation are not considered a renewable energy system as defined by PSL §66-p.

Fuel and Purchased Power Cost Adjustment Clause: See definition for Power Supply Charge.

Full-Requirements Customer: A Customer whose electric power requirements are all supplied by the Authority. (See *Customer – Full Requirements Customer*)

G

Generation Project: A specific project that is eligible to participate in the Commercial Solar, Fuel Cell, or Solar Communities Feed-In Tariffs under Service Classification No. 11 – Buy-Back Service.

I. General Information (continued):**B. Abbreviations and Definitions (continued):
Power (Electric) (continued):**

3. Peak Power is the greatest demand which occurred in a specific period of time.
4. Reactive Power is that part of Apparent Power that is not useful, but is required by some types of electricity-consuming devices such as motors.
1. Real Power is the useful part of Apparent Power. It is measured by averaging the instantaneous power over a 15-minute period and expressed in kilowatts (KW).

Power Supply Charge: Provisions made in electric rates schedules for the automatic adjustment of rates due to changes in cost of fuel and purchased power.

Primary Residence: A service address at which a Customer-generator resides the majority of the time during the year, and which has been given by the Customer-generator and exists in the voter registration catalogues or used by the Customer-generator to determine his/her school district code number as he/she identifies the same on his/her New York State Income Tax Returns

Power Factor: The Real Power (KW) divided by the Apparent Power (kVA) at any given point and time in an electrical circuit. It is expressed as a percentage. (See *Power*)

Private Property Agreement: An Agreement between the Authority and a property owner regarding the right to pass over, occupy, or use land for the placement and access of Authority facilities. The Agreement is kept on file at the Authority. (See *Right-of-Way*)

PSEG Long Island Holiday: New Year's Day, Martin Luther King, Jr. Day, Presidents' Day, Good Friday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, Day After Thanksgiving and Christmas Day

Prorate: To divide, distribute, or assess proportionately.

Public Highway: Any street, avenue, road, or way that is maintained for and used by the public. It is authorized and controlled by the legislative body of a village, town, city, county, or the State of New York.

Public Holiday: As defined in the General Construction Law Section 24, Public Holidays; half-holidays

Public Right-of-Way: The area within a Public Highway which may be used for the placement of and access to Authority facilities.

Pull Box: An underground connection between either the Authority's and the Customer's underground facilities, or the Authority's overhead, terminating at the base of a pole, and the Customer's underground facilities.

Q

Qualifying Low Income Customer: A customer who provides documentation of current enrollment in at least one of the following programs: Home Energy Assistance Program (HEAP); Medicaid; Supplemental Nutrition Assistance Program (SNAP); Supplemental Security Income (SSI); Temporary Assistance – Family Assistance (FA); Temporary Assistance-Safety Net Assistance (SNA); United States Veterans Administration – Veteran's Pension or Veteran's Surviving Spouse Pension.

R

Reactive Power: (See *Power*)

Real Power: (See *Power*)

Residence: A permanent dwelling place.

I. General Information (continued):**C. General Terms and Conditions (continued):****Net Metering (continued):**

- (b) For eligible Mass Market Projects and Large Onsite Projects with Solar or Wind or Farm Waste or Micro-Hydroelectric electric generators whose amount of electricity provided to the Authority during the billing period exceeds the amount of electricity provided by the Authority to the Customer-generator, the Authority shall apply a credit to the next bill for service at the same rate per kilowatt-hour applicable to service provided to other Customers in the same service class who do not generate electricity on site.
- (c) For eligible Mass Market Customers and Large Onsite Customers with Micro-Combined-Heat-and-Power Electric Generating Equipment or for Fuel Cell Electric Generating Equipment whose amount of electricity provided to the Authority during the billing period exceeds the amount of electricity provided by the Authority to the Customer-generator, the Authority shall apply a credit to the next bill for service at the SC-11 Avoided Cost Rate per kilowatt-hour.
- (d) For Large Onsite Customers the monthly billing demand is determined by the maximum measured kilowatt demand actually supplied to the Customer-Generator during the billing period.
- ~~(e)~~ For Customer-generators served under a rate code with multiple rating periods, excess generation in one rating may not be used to reduce the billed consumption in a different rating period. Peak, ~~and~~ off-peak ~~and super off-peak~~ periods will be treated separately when calculating and applying any credits.
- ~~(f)~~ For Customer-generators who switch to a rate code with multiple rating periods from a rate code with one rating period, all banked credits will be applied to the off-peak period bank.
- ~~(e)~~~~(g)~~ For Customer-generators who switch to a rate code with one period from a rate code with multiple rating periods, all banked credits will be applied to a single bank.
- ~~(f)~~~~(h)~~ At the end of the first year that service for eligible Mass Market Projects and Large On-site Projects with Solar, or Wind, or Farm Waste or Micro-Hydroelectric generators, and every anniversary date thereafter, the Authority shall promptly thereafter issue payment to the Customer-generator for any value of the remaining credit for the net (excess) electricity provided to the Authority by the Customer-generator during the previous twelve (12) month period. The payment issued to the Customer-generator shall be equal to the product of the remaining excess (net) energy generated by the Customer-generator times the corresponding avoided energy prices as per the Statement of Market Energy Prices.
- ~~(g)~~~~(i)~~ For eligible Mass Market Projects and Large Onsite Projects that terminate service or become ineligible for net metering, the Authority shall promptly thereafter issue payment to the Customer-generator for any value of the remaining credit for the net (excess) electricity provided to the Authority by the Customer-generator. The payment issued to the Customer-generator shall be equal to the product of the remaining net (excess) energy generated by the Customer-generator times the corresponding avoided energy prices as per the Statement of Market Energy Prices.
- ~~(h)~~~~(j)~~ The avoided cost rates to be used to issue payment to Mass Market Projects and Large Onsite Projects for energy sold to the Authority by the Customer-generator will be determined based on the simple average of the Zone K Day-Ahead Locational Based Marginal Prices (LBMP). Monthly and Time-of-Use energy payments will be shown each month on a separate Statement of Market Energy Prices.

III. Overhead and Underground Distribution of Electricity (continued):**E. Meters (continued):**3. Meter Testing

- a) The Authority will test meters if requested directly by the Customer.
- b) The Authority shall pay the cost of the testing.
- c) The Authority will perform the tests within sixty (60) days of the request, unless prevented by events it cannot control.

4. Types of Meters

The Authority will determine the type of meter installed.

5. Existing Customer without an AMI smart meter:

Effective January 1, 2019, Residential Service Classification No. 1 Customers (rates 180, 480, 481, 580), receiving service through a non-AMI equipped meter will be notified of replacement with an AMI equipped smart meter. With the following exceptions, residential Customers may opt-out of receiving the smart meter:

- a) Customers who participate in net metering;
- b) Retail choice program participants (Long Island Choice and Green Choice); and
- c) Residential Customers served under time-of-use service classifications (1-VMRP(S), ~~and~~ 1-VMRP(L)), ~~and~~ (1-VTOU).

Commercial service classifications are ineligible to opt-out of smart meter installation.

The customer will receive communication from the Authority at least 45 days prior to the install date of the AMI equipped smart meter. If the customer does not want an AMI equipped smart meter they may request that service be continued through a non-communicating meter.

Residential Service Classification No.1 Customers who do not object to installation of an AMI equipped smart meter and later request removal of the AMI equipped smart meter and replacement with a non-communicating meter will be subject to a meter removal fee as described in Section IV.C.11.

Beginning in January 1, 2023, customers who have opted out of receiving the AMI equipped smart meter will be charged a daily opt out service fee ("AMI Smart Meter Daily Opt-Out Fee") as described in Section IV.C.11.

VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS (continued):**A. Power Supply Charge (continued):**4. Power Supply Charge

a) The Power Supply Charge, expressed in cents per kWh, is calculated as the sum of: (i) the average cost of the Power Supply Charge expressed in cents per kWh, plus (ii) a rate, expressed in cents per kWh calculated to refund or recover any overcollections or undercollections of the Power Supply Charge as of the end of the preceding period. The Power Supply Charge is rounded to the nearest .0001 cents per kWh.

b) The Power Supply TOU Period Adjustment Factors are identified in the Statement of the Power Supply Charge and will be updated from time to time as follows:

(1) The Power Supply TOU Period Adjustment Factors will be calculated using the most recent average hourly load research sample results for Rate 180 or Rate 280. The rate 180 load research sample is used to calculate the Power Supply TOU Period Adjustment Factors for rate codes 190, 191, 192 and 193. The rate 280 load research sample is used to calculate the Power Supply TOU Period Adjustment factor for Rate 292.

(2) The average hourly load research samples for rate 180 or rate 280 will identify the kWh for both the super off-peak period and the peak period for each of the TOU rate codes (190, 191, 192, 193 and 292) for an annual period.

(3) For all TOU rate codes the super off-peak Power Supply TOU Period Adjustment Factor is set to 60%.

(4) For each TOU rate code, the kWh in the super off-peak period will be multiplied by the budgeted average annual Power Supply Charge multiplied by 40% (1-super off-peak Power Supply TOU Period Adjustment Factor). The subsequent dollars by TOU rate code is divided by the total kWh in the peak period to create the peak period adder by TOU Rate code. The peak period adder by TOU rate code is then added to the average annual power supply factor and divided by the average annual power supply factor, which will equal the peak Power Supply TOU period Adjustment Factor.

Formulas:

1) $(\text{kWh in Super Off-peak Period} \times \text{Annual Average Power Supply Charge} \times 40\%) / \text{Peak Period kWh} = \text{Peak Period Adder}$

2) $(\text{Peak Period Adder} + \text{Annual Average Power Supply Rate}) / \text{Annual Average Power Supply Rate} = \text{the peak Power Supply TOU period Adjustment Factor.}$

c) The Power Supply Charge for applicable TOU Rate codes will be calculated each month based on the actual Power Supply Charge (see Statement of Power Supply Charge) times the Power Supply TOU period Adjustment Factors as identified in the Statement of the Power Supply Charge.

e)d) The Authority will prepare and retain on file a Statement of the Power Supply Charge. The Statement will be available at the Authority's business offices.

VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS (continued):**F. Distributed Energy Resources Cost Recovery Rate (continued):**1. Calculation of the Distributed Energy Resources Cost Recovery Rate

The Distributed Energy Resources Cost Recovery Rate will be calculated separately for Small Customers and Large Customers. For Small Customers and Large Customers separately, the Distributed Energy Resources Cost Recovery Rate will be calculated as the sum of the eligible costs divided by the forecasted energy sales.

- a) The Authority will prepare and retain on file a "Statement of Distributed Energy Resources Cost Recovery Rate". The Statement will be available at the Authority's Business Offices.
- b) The Statement will show the authorized amounts to be recovered and the expected energy sales over which the authorized amounts will be recovered.
- c) The Distributed Energy Resources Cost Recovery Rate will be set annually, effective January 1st of each year.
- d) The Distributed Energy Resources Cost Recovery Rate may be reset during the year, based on updated values that have been approved by the Authority Board of Trustees.
- e) The Distributed Energy Resources Cost Recovery Rate will be rounded to the nearest 0.0001 cents per kWh.

2. Definition of Small and Large Customers

For purposes of the Distributed Energy Resources Cost Recovery Rate, the following definitions of Small Customers and Large Customers will apply.

- a) The Small Customer Distributed Energy Resources Cost Recovery Rate applies to:
 - (1) Service Classification No. 1 (Rate Codes: 180, 480, 481, 580)
 - ~~(2)~~ Service Classification No. 1-VMRP (Rate Codes: 181, 182, 184, 188)
 - ~~(2)(3)~~ Service Classification No. 1-VTOU (Rate Codes: 190, 191, 192, 193)
 - ~~(3)(4)~~ Service Classification No. 2 (Rate Code 280)
 - ~~(4)(5)~~ Service Classification No. 2-VMRP (Rate Code 288, 292)
 - ~~(5)(6)~~ Service Classification Nos. 5, 7, 7A and 10 (Rate Codes 980, 780, 781, 782, 1580, 1581)
 - ~~(6)(7)~~ Service Classification No. 16-AMI (Rate Code M188 and M288)
- b) The Large Customer Distributed Energy Resources Cost Recovery Rate applies to:
 - (1) Service Classification Nos. 2-L, and 2-VMRP (Rate Codes 281, 283, 291, 282, M282)
 - (2) Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)
 - (3) Service Classification Nos. 12 and 13 (Rate Codes 680, 681, 278)
- c) Retail Customers participating in the Long Island Choice or Green Choice program are subject to the Distributed Energy Resources Cost Recovery Rate according to their base rate Service Classification.
- d) Energy Service Companies (ESCOs) receiving service under Service Classification No. 14 are not subject to the Distributed Energy Resources Cost Recovery Rate.
- e) Energy delivered under the Recharge NY Power Program is not subject to the Distributed Energy Resources Cost Recovery Rate. (Rate Code 680). Energy delivered under Rate Code 680 but not under the Recharge NY Power Program is subject to the Distributed Energy Resources Cost Recovery Rate.

VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism**1. Purpose

The purpose of the Revenue Decoupling Mechanism is to recover approved Delivery Service Revenues from customers. Actual Delivery Service Revenues are reconciled to the approved Delivery Service Revenues through the Revenue Decoupling Mechanism for certain Service Classifications groups, as described below,

2. Definitions

For the purposes of the Revenue Decoupling Mechanism, the following Service Classification groups will apply.

a) Residential

(1) Service Classification No. 1 (Rate Codes: 180, 480, 481, 580)

~~(2)~~ Service Classification No. 1-VMRP (Rate Codes: 181, 182, 184, 188)

~~(2)(3)~~ Service Classification No. 1-VTOU (Rate Codes: 190, 191, 192, 193)

~~(3)(4)~~ Service Classification No. 16-AMI (Rate Code M188)

b) Small Commercial

(1) Service Classification No. 2 (Rate Code 280)

~~(2)~~ Service Classification No. 2-VMRP (Rate Code 288, 292)

~~(2)(3)~~ Service Classification No. 16-AMI (Rate Code M288)

c) Large Commercial excluding mandatory demand metered service with multiple rate periods:

(1) Service Classification No. 2-L (Rate Codes 281, 283, 291)

(2) Service Classification No. 2L-VMRP (Rate Codes 282, M282)

d) Mandatory Large Demand Metered Service with Multiple Rate Periods

(1) Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)

VIII. SERVICE CLASSIFICATIONS:**A. SERVICE CLASSIFICATION NO. 1 - Residential Service:
(Rate Codes: 180, 480, 481, 580)**1. Who Is Eligible

a) A Customer who will use the service for residential purposes or as specified in Section 76 of the Public Service Law, for religious purposes, a Community Residence, or a post or hall owned or leased by a not-for-profit corporation that is a Veterans' Organization.

b) A Customer, as described in a. above, that has the option under Service Classification Nos. 12 – Backup and Maintenance Service, of choosing to pay the rates and charges associated with a different Service Classification.

c) Effective January 1, 2021, rates 480 and 481 are no longer available to new or transferring customers.

d) Effective January 1, 2025, rates 480 and 481 are no longer available to customers. Customers participating in this rate code as of December 31, 2024 will be transferred to Service Classification No. 1 rate code 180 unless they request transfer to Rate Code 1-VTOU at least 30 days before that date.

2. Character of Service

a) Continuous, 60 hertz, alternating current.

b) Approximately 120/208 or 120/240 volts, single or three phase, depending on the characteristics of the load and the circuit supplying the service.

VIII. SERVICE CLASSIFICATIONS (continued):**A. SERVICE CLASSIFICATION NO. 1-VMRP (L)****Voluntary Large Residential Service with Multiple Rate Periods:**
(Rate Codes: 181, 182, 184)1. Who Is Eligible

- a) An existing Customer receiving service under Service Classification Nos. 1 or 1-VMRP who chooses to receive service under this classification and:
 - (1) Uses more than 39,000 kWh annually for the twelve (12) months ending September 30, or
 - (2) Uses more than 12,600 kWh for the 4-month period between June 1 and September 30.
- b) An Applicant eligible to receive service under Service Classification No. 1 whose consumption the Authority estimates will be more than either 39,000 KWH annually or 12,600 KWH between June 1 and September 30.
- c) A Customer, as described in a. through b. above, that has the option under Service Classification Nos. 12 – Backup and Maintenance Service, of choosing to pay the rates and charges associated with a different Service Classification.
- d) Effective January 1, 2019, this service classification is no longer available to new or transferring customers. Customers may request Service Classification No. 16. [or Service Classification No. 1-VTOU.](#)
- ~~e)~~ Effective January 1, 2025, this service classification is no longer available to customers. Customers participating in this rate code as of December 31, 2024 will be transferred to Service Classification No. 1 (rate code 180 or rate code 580 as appropriate) unless they request transfer to Rate Code 1-VTOU at least 30 days before that date.

2. Character of Service

- a) Continuous, 60 hertz, alternating current.
- b) Approximately 120/208, 120/240, or 277/408 volts, single or three phase, depending on the characteristics of the load and the circuit supplying the service.

VIII. SERVICE CLASSIFICATIONS (continued):**B. SERVICE CLASSIFICATION NO. 1-VMRP (L)****Voluntary Large Residential Service with Multiple Rate Periods (continued):**
(Rate Codes: 181, 182, 184)**Special Provisions (continued):**a) Service for Religious Purposes, Community Residences, or Veterans' Organizations

Customers under this Service Classification who use electricity for religious purposes, for Community Residences, or Veterans' Organizations as specified in Section 76 of the Public Service Law, may apply for a suitable non-residential service after a minimum term of one (1) year.

- (1) The transferring Customer shall submit a new Application to the Authority before the transfer, and
- (2) The transfer will take place at the Customer's next meter reading.

b) Choosing a Rate

- (1) New space-heating Customers shall choose either Rate Code 182 or 184 when they qualify for service.
- (2) New non-space-heating Customers shall choose either Rate Code 181 or 184 when they qualify for service.

~~(3) Effective January 1, 2019, this service classification is no longer available to new or transferring customers. Customers may request Service Classification No. 16.~~

c) Transferring Between Rates Under This Service Classification(1) Space-heating Customers

- (a) Customers served under Rate Code 184 may request to transfer to Rate Code 182 before, but not after January 1, 2019.
- (b) The Customer shall request the transfer, in writing, at least thirty (30) days before the Customer's Anniversary Date, and
- (c) The transfer will take place on the Anniversary Date.

(2) Non-space-heating Customers

- (a) Customers served under Rate Code 184 may request to transfer to Rate Code 181 before, but not after January 1, 2019.
- (b) The Customer shall request the transfer, in writing, at least thirty (30) days before the Customer's Anniversary Date, and
- (c) The transfer will take place on the Anniversary Date.

- (3) Customers with AMI meters may transfer out of this service classification to Rate Code M188 at any time.

VIII. SERVICE CLASSIFICATIONS (continued):**C. SERVICE CLASSIFICATION NO. 1-VMRP(S)
Voluntary Small Residential Service With Multiple Rate Periods:
(Rate Code: 188)**1. Who Is Eligible

- a) Qualifying Applicants who will use the service for residential purposes or as specified in Section 76 of the Public Service Law, for religious purposes, a Community Residence, or a post or hall owned or leased by a not-for-profit corporation that is a Veterans' Organization as an alternative to Service Classification No. 1, but who do not qualify for Service Classification No. 1-VMRP(L).
- b) A Customer, as described in a. above, that has the option under Service Classification Nos. 12 – Backup and Maintenance Service, of choosing to pay the rates and charges associated with a different Service Classification.
- c) Effective January 1, 2019, this service classification is no longer available to new or transferring customers. Customers may request Service Classification No. 16 or Service Classification No. 1-VTOU.
- ~~e)d) Effective January 1, 2025, this service classification is no longer available to customers. Customers participating in this rate code as of December 31, 2024 will be transferred to Service Classification No. 1 (rate code 180 or rate code 580 as appropriate) unless they request transfer to Rate Code 1-VTOU at least 30 days before that date.~~
- c)

2. Character of Service

- a) Continuous, 60 hertz, alternating current.
- b) Approximately 120/208, 120/240 volts, single or three phase, depending on the characteristics of the load and the circuit supplying the service.

VIII. SERVICE CLASSIFICATIONS (continued):**D. SERVICE CLASSIFICATION NO. 1-VTOU**
Voluntary Service With Time of Use Rates:
(Rate Code: 190, 191, 192, 193)**3. Who Is Eligible**

- a) Qualifying Applicants who will use the service for residential purposes or as specified in Section 76 of the Public Service Law, for religious purposes, a Community Residence, or a post or hall owned or leased by a not-for-profit corporation that is a Veterans' Organization as an alternative to Service Classification No. 1, but who do not qualify for Service Classification No. 1-VMRP(L).
- b) A Customer, as described in a. above, that has the option under Service Classification Nos. 12 – Backup and Maintenance Service, of choosing to pay the rates and charges associated with a different Service Classification.
- c) Customers must have that Advanced Metering Infrastructure (AMI) installed to qualify.
- d) Customers are not eligible to return to Rate Code 190, 191, or 192 for a period of 12 months from their date of exit from Rate Code 190, 191, or 192.

4. Character of Service

- a) Continuous, 60 hertz, alternating current.
- b) Approximately 120/208, 120/240 volts, single or three phase, depending on the characteristics of the load and the circuit supplying the service.

5. Seasons

Summer Season: June 1 through September 30 inclusive
Shoulder Season: October 1 through November 30 and April 1 through May 31 inclusive
Winter Season: December 1 through March 31 inclusive

6. Periods:

Each rate will have multiple time periods in each day. The time periods are defined within the schedule of rates for each rate code.

7. Power Supply Charges:

- a) The Power Supply Charge will vary for each period.
- b) The Authority will publish the rates as part of the Statement of Power Supply Charge. The Statement will be available at the Authority's business offices.

VIII. SERVICE CLASSIFICATIONS (continued):

B. SERVICE CLASSIFICATION NO. 1-VTOU

Voluntary Residential Service with Time of Use Rates (continued):
(Rate Code: 190, 191, 192, 193)

6. Rates & Charges Per Meter:

a) Schedule of Rates:

The Rates for this service code are set below:

Rate Code 190

Service Charge per Day: \$0.XX per day

<u>Energy Charge per kWh</u>	<u>Summer Season</u>	<u>Winter Season</u>	<u>Shoulder Season</u>
<u>Peak</u>	<u>\$ 0.XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Super Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>

* Super Off-Peak ~60% of Rate 180, Off-Peak will equal Rate 180 and Peak will be ~2.1 times the rate for 180 customers.

Periods:

Peak: 4:00 PM – 7:00 PM Monday through Friday excluding Federal Holidays

Off-Peak: 6:00 AM – 4:00 PM and 7:00 PM – 10:00 PM Monday through Friday, and 6:00 AM – 10:00 PM on Saturday, Sunday and Federal Holidays

Super Off-Peak: 10:00 PM – 6:00 AM all days

Rate Code 191

Service Charge per Day: \$0.XX per day

<u>Energy Charge per kWh</u>	<u>Summer Season</u>	<u>Winter Season</u>	<u>Shoulder Season</u>
<u>Peak</u>	<u>\$ 0.XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Super Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>

* Super Off-Peak ~60% of Rate 180, Off-Peak will equal Rate 180 and Peak will be ~1.8 times the rate for 180 customers.

Periods:

Peak: 4:00 PM – 8:00 PM Monday through Friday excluding Federal Holidays

Off-Peak: 7:00 AM – 4:00 PM and 8:00 PM – 11:00 PM Monday through Friday, and 7:00 AM – 11:00 PM on Saturday, Sunday and Federal Holidays

Super Off-Peak: 11:00 PM – 7:00 AM all days

VIII.SERVICE CLASSIFICATIONS (continued):

B. SERVICE CLASSIFICATION NO. 1-VTOU

Voluntary Residential Service with Time of Use Rates (continued):

(Rate Code: 190, 191, 192, 193)

Rates & Charges Per Meter (continued):

Rate Code 192

Service Charge per Day: \$0.XX per day

<u>Energy Charge per kWh</u>	<u>Summer Season</u>	<u>Winter Season</u>	<u>Shoulder Season</u>
<u>Peak</u>	<u>\$ 0.XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Super Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>

* Super Off-Peak ~60% of Rate 180, Off-Peak will equal Rate 180 and Peak will be ~1.9 times the rate for 180 customers.

Periods:

Peak: 3:00 PM – 7:00 PM Monday through Friday excluding Federal Holidays

Off-Peak: 6:00 AM – 3:00 PM and 7:00 PM – 10:00 PM Monday through Friday,
and 6:00 AM – 10:00 PM on Saturday, Sunday and Federal Holidays

Super Off-Peak: 10:00 PM – 6:00 AM all days

Rate Code 193

Service Charge per Day: \$0.XX per day

<u>Energy Charge per kWh</u>	<u>Summer Season</u>	<u>Winter/Shoulder Season</u>
<u>Daytime</u>	<u>\$ 0.XXXX</u>	<u>\$ 0. XXXX</u>
<u>Nighttime</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>

* Daytime will equal ~1.1 times Rate 180 and Nighttime will be 60% of the rate for 180 customers.

Periods:

Daytime: 6:00 AM – 11:00 PM all days

Nighttime: 11:00 PM – 6:00 AM all days

VIII. SERVICE CLASSIFICATIONS (continued):**B. SERVICE CLASSIFICATION NO. 1-VTOU****Voluntary Residential Service with Time of Use Rates (continued):****(Rate Code: 190, 191, 192, 193)****Rates & Charges Per Meter (continued):****b) Adjustments to Rates and Charges**

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

7. Minimum Charge

The Minimum Charge is the Service Charge, plus Adjustments to Rates and Charges.

8. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late Payments shall be subject to Late Payment Charges.

9. Term of Service

The Authority will provide service to the Customer until service is terminated either by the Customer or the Authority.

a) The Customer shall give the Authority five (5) days written notice when requesting termination of service.

b) The Authority may terminate service to the Customer in accordance with the provisions of this Tariff.

10. Special Provisions**a) Service for Religious Purposes, Community Residences, or Veterans' Organizations**

(1) Customers under this Service Classification who use electricity for religious purposes, for Community Residences, or Veterans' Organizations as specified in A.1.a. above, may apply for a suitable non-residential service after a minimum term of one (1) year.

(2) The transferring Customer shall submit a new Application to the Authority before the transfer, and the transfer will take place at the time of the Customer's next meter reading.

VIII. SERVICE CLASSIFICATIONS (continued):**D. SERVICE CLASSIFICATION NO. 2-VMRP****Voluntary Small General Service With Multiple Rate Periods:****(Rate Code: 288, 292)**1. Who Is Eligible

a) Customers who will use the service on a voluntary basis as an alternative to Service Classification 2, for any purposes other than Residential, when the Authority estimates that the Applicant's demand will be less than 7 KW, subject to Special Provision 7.b. below.

b) A Customer, as described in a. above, that has the option under Service Classification Nos. 12 – Backup and Maintenance Service, of choosing to pay the rates and charges associated with a different Service Classification.

c) For Rate Code 292, customers must have Advanced Metering Infrastructure (AMI) installed to qualify.

↳d) Customers who are not eligible for: Voluntary Small General Service with Multiple Rate Periods (2-VMRP):

(1) Effective January 1, 2019, this service classification Rate Code 288 is no longer available to new or transferring customers. Customers may request Rate Code 292 or Service Classification No. 16.

(+)(2) A customer is not eligible to return to Rate Code 292 for a period of 12 months from its date of exit from Rate Code 292.

2. Character of Service

a) Continuous, 60 hertz, alternating current.

b) Radial secondary service at approximately 120/208, 120/240 or 277/480 volts, single or three phase; network system 120/208 or 277/480 single or three phase; depending on the size and characteristics of the load and the circuit supplying the service.

3. Seasons (for Rate Code 292)

Summer Season: June 1 through September 30 inclusive

Winter Season: December 1 through March 31 inclusive

Shoulder Season: April 1 through May 31 inclusive and October 1 through November 30 inclusive

4. Periods

The rates will have multiple time periods in each day. The time periods within the schedule of rates for each rate code.

5. Power Supply Charges (for Rate Code 292):

a) The Power Supply Charge will vary for each period.

↳b) The Authority will publish the rates as part of the Statement of Power Supply Charge. The Statement will be available at the Authority's business offices.

VIII. SERVICE CLASSIFICATIONS (continued):

E. SERVICE CLASSIFICATION NO. 2-VMRP

Voluntary Small General Service With Multiple Rate Periods: (continued)
(Rate Code: 288, 292)

6. Rates and Charges per Meter:

a) Schedule of Rates

The rates for this service code are found below

<u>Rate Code 288</u>	<u>June to September Inclusive</u>	<u>October to May Inclusive</u>
Meter Charge per day	\$.1200	\$.1200
Service Charge per day	\$.4200	\$.4200
Energy Charge per kWh		
Daylight Savings Time 8 p.m. to 10 a.m., and Saturday and Sunday	<u>Period 1</u> \$.0529	<u>Period 2</u> \$.0344
Daylight Savings Time 10 a.m. to 8 p.m. Weekdays	<u>Period 3</u> \$.3351	<u>Period 4</u> \$.0932

Rate Code 292

Service Charge per day \$.XX

<u>Energy Charge per kWh</u>	<u>Summer Season</u>	<u>Winter Season</u>	<u>Shoulder Season</u>
<u>Peak</u>	<u>\$ 0.XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>
<u>Super Off-Peak</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>	<u>\$ 0. XXXX</u>

* Super Off-Peak ~60% of Rate 280, Off-Peak will equal Rate 180 and Peak will be ~1.8 times the rate for 280 customers.

Periods:

Peak: 3:00 PM – 7:00 PM Monday through Friday excluding Federal Holidays

Off-Peak: 6:00 AM – 3:00 PM and 7:00 PM – 11:00 PM Monday through Friday,
and 6:00 AM – 11:00 PM on Saturday, Sunday and Federal Holidays

Super Off-Peak: 11:00 PM – 6:00 AM all days

b) Adjustments to Rates and Charges

Each Customer's bill will be adjusted for the Power Supply Charge, Increases in Rates and Charges to Recover PILOT Payments, the Shoreham Property Tax Settlement Rider, the Distributed Energy Resources Cost Recovery Rate, the New York State Assessment Factor, Revenue Decoupling Mechanism, the Securitization Offset Charge, and the Delivery Service Adjustment.

~~7.6. Minimum Charge~~

~~The Minimum Charge is the Service and Motor Charge, plus Adjustments to Rates and Charges.~~

~~8.6. Terms of Payment~~

~~The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.~~

VIII. SERVICE CLASSIFICATIONS (continued):**E. SERVICE CLASSIFICATION NO. 2-VMRP****Voluntary Small General Service With Multiple Rate Periods: (continued)**
(Rate Code: 288, 292)**7. Minimum Charge**

The Minimum Charge is the Service and Meter Charge, plus Adjustments to Rates and Charges.

8. Terms of Payment

The Customer shall pay the balance due in cash, including checks and money orders, on receiving the bill. Late payments shall be subject to Late Payment Charges.

9. Term of Service

~~The Authority will provide service to the Customer for one (1) year from the start of service and renewed annually after that, unless service is terminated either by the Customer or the Authority.~~

~~a) The Customer shall give the Authority five (5) days written notice before its Anniversary Date when requesting termination of service.~~

~~b) The Authority may terminate service to the Customer in accordance with the provisions of this Tariff.~~

~~The Authority will not renew service within one (1) year of termination at the same location for the same Customer.~~

~~a) The Authority will provide service to the Customer until service is terminated either by the Customer or the Authority.~~

~~b) The Customer shall give the Authority five (5) days written notice when requesting termination of service.~~

~~c) The Authority may terminate service to the Customer in accordance with the provisions of this Tariff.~~

10. Special Provisions**a) Corrective Equipment Requirements**

When the installation includes welders, x-rays, or other apparatus having a highly fluctuating or large instantaneous demand, the Customer shall provide batteries, rotating equipment, or other corrective equipment to reduce the inrush current to an amount acceptable to the Authority.

b) Transfer to Service Classification Nos. 2-L, or 2L-VMRP

(1) Customers will be transferred to Service Classification Nos. 2-L, or 2L-VMRP when:

(a) For monthly-billed Customers, electric use during the last twelve (12) months has equaled or been greater than 2000 KWH in each of two (2) consecutive monthly billing periods, or

- (b) For bimonthly-billed Customers, electric use during the last twelve (12) months has equaled or been greater than 4000 KWH in two (2) consecutive bimonthly billing periods.
- (2) The transfer will take place within ninety (90) days after the Authority certifies that the Customer qualifies for the service.

VIII. SERVICE CLASSIFICATIONS (continued):**E. SERVICE CLASSIFICATION NO. 2-VMRP****Voluntary Small General Service With Multiple Rate Periods: (continued)****(Rate Code: 288, ~~292~~)****Special Provisions (continued):**c) Excelsior Jobs Program

The Excelsior Jobs Program is intended to encourage businesses to expand or relocate to the Authority's Service Area.

(1) The Authority's discount is available to certified participants who increase their load by at least 25%, to a minimum of 7 KW within one year of Excelsior Jobs Program certification, and

(2) Customers who qualify would be transferred to an appropriate demand-meter rate (Service Classifications 2-L, 2L-VMRP, or 2-MRP) and receive rate discounts on charges for the additional energy used as stated under that Service Classification.

d) Service for Religious Purposes, Supervised Community Residences or Veterans' Organizations

(1) Customers under this Service Classification who use electricity for religious purposes, for Community Residences or Veterans' Organizations as specified in Section 76 of the Public Service Law, may apply for a suitable residential service after a minimum term of one (1) year.

(2) The transferring Customer shall submit a new Application to the Authority before the transfer, and

(3) The transfer will take place at the time of the Customer's next meter reading.

IX. Long Island Choice Program (continued):**C. SERVICE CLASSIFICATION NO. 14 ESCO and DRC Services (continued):****(Rate Codes: 390)****Rates, Charges and Credits per Month (continued):**

- (1) Special Meter Reading: ESCOs and DRCs may request a special meter read before the regularly scheduled read, providing the request is made seventy-two (72) hours before the date the read is needed. The ESCO or DRC shall pay the following charges:

<u>Description</u>	<u>Charge</u>
(a) Site visits during the hours of 8:30 a.m. to 4:00 p.m., weekdays excluding <u>PSEG Long Island</u> holidays	\$32.05
(b) Site visits during the hours of 4:00 p.m. through 7:00 p.m. on weekdays or 8:30 a.m through 4:00 p.m. on Saturday, when requested by the ESCO	\$37.75

XIII. Dynamic Load Management**A. Direct Load Control Program****1. Purpose and Applicability:**

The Direct Load Control ("DLC") Program allows the Authority to remotely control the Participating Customer's Control Device to reduce the Customer's load during an Event. The program utilizes third-party Control Devices Providers to identify Participants and install and manage the Control Devices that meet the Authority's specifications for communications.

Participation is applicable to Customers served at Primary and Secondary voltage in the Service Classifications listed below in all locations within the Service Area, except for those described in the Statement of Direct Load Control Program Payments.

Service Classification No. 1 (Rate Codes 180, 580; excluding 480 and 481)

Service Classification No. 1-VMRP (L) (Rate Codes 181, 182, 184)

Service Classification No. 1-VMRP(S) (Rate Code 188)

Service Classification No. 1-VTOU (Rate Codes 190, 191, 192, 193)

Service Classification No. 2 (Rate Code 280)

Service Classification No. 2-VMRP (Rate Code 288, 292)

Service Classification No. 2-L (Rate Codes 281, 291, 283)

Service Classification No. 2L-VMRP (Rate Codes 282, M282)

Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)

Service Classification No. 16-AMI (Rate Codes M188, M288)

2. Eligibility:

To participate under this program, a Customer must have load controllable equipment and agree to the installation of a Control Device.

This program is not available to Customers who participate either directly or indirectly through a third party, under any other Authority or NYISO demand-response program.

The Manager may, in the future, offer an alternate direct load control program through a third-party vendor to customers in a defined geographic area. In coordination with non-wires alternatives such as these, eligibility for the DLC program for Customers within such designated area(s) may be temporarily restricted such that only Customers who have applied to and been rejected from the alternate third-party vendor program will be eligible for enrollment within the Authority's DLC program. Such restriction on application to the DLC program shall cease upon the earlier of (a) the date on which the alternate program achieves the amount of peak load reduction in the designated area specified by the Manager, and (b) the exclusivity deadline specified by the Manager. A list of geographic areas in which this provision applies will be set forth in the Statement of Direct Load Control Program Payments which will be amended from time to time to reflect new and completed alternate programs.

3. Definitions:

Control Device: A device installed on the Customer's load controllable equipment via a smart plug or embedded control that allows the Authority to remotely control the equipment when an Event is called. For purposes of this program, Control Device means one or more devices as may be required to control the equipment. Each Control Device contains a feature that allows the Customer to override the Authority's control of the Customer's equipment. The Control Device must be provided, installed, and connected to the Internet by the Customer or an approved Control Device Provider in a manner that ensures communications between the Authority and the Control Device.

XIII. Dynamic Load Management**A. Commercial System Relief Program****1. Purpose and Availability**

The Commercial System Relief Program is being offered by the Authority to enable participating eligible customers to be compensated for reducing their load under certain conditions when called upon by the Authority to do so.

The program is available to any Customer served at transmission, primary or secondary voltage and taking service under one of the Service Classifications shown below; and to any Aggregator that meets the requirements of this Rider.

Service Classification No. 1 (Rate Codes 180, 580; excluding 480, 481)

Service Classification No. 1-VMRP(L) (Rate Codes 181, 182, 184)

Service Classification No. 1-VMRP(S) (Rate Codes 188)

Service Classifications No. 1-VTOU (Rate Codes 190, 191, 192, 193)

Service Classification No. 2 (Rate Code 280)

Service Classification No. 2-VMRP (Rate Code 288, 292)

Service Classification No. 2-L (Rate Codes 281, 291, 283)

Service Classification No. 2L-VMRP (Rate Codes 282, M282)

Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)

Service Classification Nos. 11, 12, and 13 (Rate Codes 289, 680, 681, 278)

Service Classification No. 16-AMI (Rate Code M188, M288)

Customers who take service pursuant to the Direct Load Control Program are not eligible to participate in this program.

Customer-generators subject to Value Stack compensation may choose to waive the DRV compensation of the Value Stack and opt-in to participating in the Commercial System Relief Program (CSRP). Opting into the CSRP program is a one-time irreversible decision which may be made at any point during the project's Value Stack compensation period.

The Metropolitan Transportation Authority for Traction Power Service to the Long Island Rail Road and Brookhaven National Laboratories pursuant to a Sale for Resale agreement between the Authority and the New York Power Authority (both as referenced on Leaf 271) are not eligible to participate.

2. Definitions:

Aggregator: A party other than the Authority that represents and aggregates the load of Customers who collectively have a Load Relief potential of 50 kW or greater in an Authority Designated Area and is responsible for the actions of the Customers it represents, including performance and, as applicable, repayments to the Authority. A Direct Participant may combine multiple customer locations to meet the Load Relief potential requirements of an aggregator.

Authority Designated Area: An electrically defined area determined by the Authority to be approaching system capacity limits during peak periods. A current list of the Authority Designated Areas will be listed on the Manager's website and payments by area are listed on the Statement of Commercial System Relief Program Payments.

Capability Period: The period during which the Authority can request Load Relief. The Capability Period will be from May 1 through September 30.

XIII. Dynamic Load Management

A. Commercial System Relief Program (continued): Definitions (continued):

CBL: A Customer Baseline Load Verification Methodology is calculated using one of the following three methods: (1) "5 of 10 Day Weather-Adjusted CBL"; (2) "5 of 10 Average-Day CBL"; or (3) "10 Day Weather-Adjusted CBL". The Customer Baseline Load methodologies are further described in the Authority's DLM operating procedures, which is available on the Manager's website.

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

Contracted Hours: The four-hour period within a weekday, Monday through Friday during the Capability Period excluding ~~federal holidays~~ PSEG Long Island Holidays, during which the Direct Participant or Aggregator contracts to provide Load Relief in an Authority Designated Area whenever the Authority designates a Planned Event. The Load Relief Period will be identified for each Authority Designated Area on the Manager's website.

Direct Participant: A Customer who enrolls under this Program directly with the Authority for a single account and agrees to provide at least 50 kW of Load Relief.

Electric Generating Equipment: (a) electric generating equipment that is served under Service Classification Nos. 11 or 12 and used to provide Load Relief under this Program; or (b) emergency electric generating equipment that is interconnected and operated in compliance with Authority rules governing Emergency Generating Facilities used for self supply and used to provide Load Relief under this Program.

Load Relief: Power (kW) and energy (kWh): (a) ordinarily supplied by the Authority that is displaced by use of Electric Generating Equipment and/or reduced by the Direct Participant or Aggregator at the Customer's premises; or (b) that is produced by use of Electric Generating Equipment by a customer taking service pursuant to Service Classification No. 11 and delivered by that Customer to the Authority's distribution system during a Load Relief Period.

Load Relief Period: The hours for which the Authority requests Load Relief when it designates a Planned Event or an Unplanned Event.

New Participant: An Aggregator or Direct Participant that has not previously participated in a call for Load Relief under the Commercial System Relief Program.

Performance Adjusted kW: The kW level that a Direct Participant or Aggregator requests to provide subsequent to the Direct Participant or Aggregator performance during an event

XIII. Dynamic Load Management**A. Commercial System Relief Program (continued):****3. Applications for Participation**

- a) Applications for participation under this program must be made electronically. Direct Participants and Aggregators may participate after the Authority's receipt and approval of a completed application. The Authority will accept an application by April 1 for a May 1 commencement date, by May 1 for a June 1 commencement date, or by June 15 for a July 1 commencement date. However, if the application is received by April 1 and the Authority does not bill the participant monthly using interval metering at the time of application, participation may commence on July 1 provided all conditions in section XIII.B.6. are satisfied.
- b) The desired commencement month must be specified in the application. Applications will not be accepted after the specified date for participation during the current Capability Period. If the first of the month falls on a weekend or ~~holiday~~ PSEG Long Island Holiday, applications will be accepted until the first business day thereafter.
- c) The Authority will accept applications for participation in the Voluntary Participation Option under the Program at any time provided the metering and communications requirements are satisfied as specified in Section XIII.B.6.
- d) Participants without Qualifying Paired Battery Storage Equipment and without Eligible Net Metering Technology will receive the "5 of 10 Day Weather Adjusted CBL" as the default CBL Verification Methodology unless the application specifies that the "10 Day Weather – Adjusted CBL" or the "5 of 10 Average-Day CBL" is to be used for verification of performance. A single CBL Verification Methodology will be used for each customer to assess both energy (kWh) and demand (kW) Load Relief.
- e) Qualifying Paired Battery Storage Equipment and Eligible Net Metering Technology will receive the "10 Day Weather-Adjusted CBL" for verification of performance.
- f) Participants without Qualifying Paired Battery Storage Equipment and without Eligible Net Metering Technology may apply in writing prior to the start of the Capability Period to change the CBL Verification Methodology.
- g) A Direct Participant or Aggregator may apply in writing, prior to the start of the Capability Period, to change the kW of pledged Load Relief, or to terminate service under this Program for the upcoming Capability Period provided the request is received prior to commencing participation for that Capability Period. In order for a Direct Participant or Aggregator to increase its kW of contracted Load Relief in an Authority Designated Area, the Direct Participant's or Aggregator's most recent Performance Factor in that Authority Designated Area must be no less than 1.00.
- h) Each application must state the kW of Load Relief that the Direct Participant or Aggregator contracts to provide for the Load Relief Period. Load Relief of an Aggregator will be measured on a portfolio basis separately for each Authority Designated Area.

4. Notification by the Authority and Required Response

The Authority will notify Direct Participants and Aggregators by phone, e-mail, or machine-readable electronic signal, or a combination thereof, in advance of the commencement of a Load Relief Period or Test Event. The Direct Participant or Aggregator will designate in writing an authorized representative and an alternate representative, and include an electronic address if applicable, to receive the notice. If an Aggregator is served under this Program, only the Aggregator will be notified of the Load Relief Period or Test Event. The Aggregator is responsible for notifying all of the customers within its respective aggregation group.

XIII. Dynamic Load Management

B. Distribution Load Relief Program

1. Purpose and Availability

The Distribution Load Relief Program is being offered by the Authority to enable participating eligible customers to be compensated for reducing their load under certain conditions when called upon by the Authority to do so.

The program is available to any Customer served at primary or secondary voltage and taking service under one of the Service Classifications shown below; and to any Aggregator that meets the requirements of this Rider.

Service Classification No. 1 (Rate Codes 180, 580; excluding 480, 481)

Service Classification No. 1-VMRP(L) (Rate Codes 181, 182, 184)

Service Classification No. 1-VMRP(S) (Rate Codes 188)

Service Classifications No. 1-VTOU (Rate Codes 190, 191, 192, 193)

Service Classification No. 2 (Rate Code 280)

Service Classification No. 2-VMRP (Rate Code 288, 292)

Service Classification No. 2-L (Rate Codes 281, 291, 283)

Service Classification No. 2L-VMRP (Rate Codes 282, M282)

Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)

Service Classification Nos. 11, 12, and 13 (Rate Codes 289, 680, 681, 278)

Service Classification No. 16-AMI (Rate Code M188, M288)

Customers who take service pursuant to the Direct Load Control Program are not eligible to participate in this program.

The Metropolitan Transportation Authority for Traction Power Service to the Long Island Rail Road and Brookhaven National Laboratories pursuant to a Sale for Resale agreement between the Authority and the New York Power Authority (both as referenced on Leaf 271) are not eligible to participate.

2. Definitions:

Aggregator: A party other than the Authority that represents and aggregates the load of Customers who collectively have a Load Relief potential of 50 kW or greater in an Authority Designated Area and is responsible for the actions of the Customers it represents, including performance and, as applicable, repayments to the Authority. A Direct Participant may combine multiple customer locations to meet the Load Relief potential requirements of an Aggregator.

Authority Designated Area: An electrically defined area determined by the Authority to be approaching system capacity limits during peak periods. A current list of the Authority Designated Areas will be listed on the Manager's website and Reservation Payments by area are listed on the Statement of Distribution Load Relief Program Payments.

Capability Period: The period during which the Authority can request Load Relief. The Capability Period will be from May 1 through September 30.

XIII. Dynamic Load Management

C. Distribution Load Relief Program (continued):

4. Applications for Participation

- a) Applications for participation under this program must be made electronically. Direct Participants and Aggregators may participate after the Authority's receipt and approval of a completed application. The Authority will accept an application by April 1 for a May 1 commencement date, by May 1 for a June 1 commencement date, or by June 15 for a July 1 commencement date. However, if the application is received by April 1 and the Authority does not bill the participant monthly using interval metering at the time of application, participation may commence on July 1 provided all conditions in section XIII.C.7. are satisfied. Applicants with existing requisite metering and communication capabilities as specified in Section XIII.B.6. who wish to participate in the program on a voluntary basis may apply at any time.
- b) The desired commencement month must be specified in the application. Applications will not be accepted after the specified date for participation during the current Capability Period. If the first of the month falls on a weekend or ~~holiday~~ PSEG Long Island Holiday, applications will be accepted until the first business day thereafter.
- c) Participants without Qualifying Paired Battery Storage Equipment and without Eligible Net Metering Technology, the "5 of 10 Day Weather Adjusted CBL" will be the default CBL Verification Methodology, unless the application specifies that the "10 Day Weather-Adjusted CBL" or "5 of 10 Day Average-Day CBL" is to be used for verification of performance. A single CBL Verification Methodology will be used for each customer to assess both energy (kWh) and demand (kW) Load Relief.
- d) Qualifying Paired Battery Storage Equipment and Eligible Net Metering Technology will receive the "10 Day Weather-Adjusted CBL" for verification of performance.
- e) Participants without Qualifying Paired Battery Storage Equipment and without Eligible Net Metering Technology may apply in writing prior to the start of the Capability Period to change the CBL Verification Methodology.
- f) A Direct Participant or Aggregator may apply in writing prior to the start of the Capability Period, to change the kW of pledged Load Relief, or to terminate service under this Program for the upcoming Capability Period provided the request is received prior to commencing participation for that Capability Period. In order for a Direct Participant or Aggregator to increase its kW of contracted Load Relief in an Authority Designated Area, the Direct Participant's or Aggregator's most recent Performance Factor in that Authority Designated Area must be no less than 1.00.
- g) Each application must state the kW of Load Relief that the Direct Participant or Aggregator contracts to provide for the Load Relief Period. Load Relief of an Aggregator will be measured on a portfolio basis separately for each Authority Designated Area.

5. Load Relief Period Criteria

- a) Criteria for Designating a Load Relief Period: If the Authority declares a need for emergency or non-emergency relief, within the limitations described by 40 CFR 63.6640 subparts (f) (2) and (f)(4,) or if a voltage reduction of five percent or greater has been ordered, the Authority may designate such period as a Load Relief Period. The Authority may designate specific feeders or geographical areas in which Load Relief shall be requested.

Long Island Power Authority

Statement of Power Supply Charge

Applicable to billings under all Service Classifications
As set forth in the Tariff for Electric Service

Applicable to billings under all Service Classifications other than Service Classifications No. 1-VTOU and No. 2-VMRP as set forth in the Tariff for Electric Service

Power Supply Charge as adjusted to Achieve
Targeted Level of Revenues, cents/kWh (1)x.xxxx

Applicable to billings under Service Classification No. 1-VTOU and No. 2-VMRP Rate Code 292 as set forth in the Tariff for Electric Service

<u>Rate Code</u>	<u>Power Supply TOU Period</u>			<u>TOU Power Supply Charge</u>		
	<u>Peak Hours</u>	<u>Adjustment Factors</u>		<u>Peak Hours</u>	<u>TOU Power Supply Charge</u>	
		<u>Off-Peak Hours / Day</u>	<u>Super Off-Peak Hours</u>		<u>Off-Peak Hours / Day</u>	<u>Super Off-Peak Hours</u>
	<u>Time Hours</u>			<u>Time Hours</u>		
<u>190</u>	<u>198.72%</u>	<u>100%</u>	<u>60%</u>	<u>x.xxxx</u>	<u>x.xxxx</u>	<u>x.xxxx</u>
<u>191</u>	<u>169.44%</u>	<u>100%</u>	<u>60%</u>	<u>x.xxxx</u>	<u>x.xxxx</u>	<u>x.xxxx</u>
<u>192</u>	<u>176.89%</u>	<u>100%</u>	<u>60%</u>	<u>x.xxxx</u>	<u>x.xxxx</u>	<u>x.xxxx</u>
<u>193</u>	<u>n/a</u>	<u>111.57%</u>	<u>60%</u>	<u>n/a</u>	<u>x.xxxx</u>	<u>x.xxxx</u>
<u>292</u>	<u>161.08%</u>	<u>100%</u>	<u>60%</u>	<u>x.xxxx</u>	<u>x.xxxx</u>	<u>x.xxxx</u>

(1) The Average Cost of the Power Supply Charge, as adjusted to Achieve Targeted Level of Revenues, is set pursuant to the Board of Trustees' March 27, 2003, April 27, 2006, June 22, 2006 and October 25, 2012 resolutions, which provide for recovery of approximately \$~~188-XXX~~ million of targeted revenues for the month of ~~August 2020~~February 2021.

Effective: ~~August 1, 2020~~February 1, 2021

Exhibit B-2 - CDG Net Crediting Tariff Redline

Table of Contents (continued):

Additional Documents

Feed-In Tariff Solar Power Purchase Agreement ("PPA")

Long Island Choice Operating Procedures ("Operating Procedures")

[PSEG Long Island's Community Distributed Generated \(CDG\) Net Crediting Manual](#)

Smart Grid Small Generator Standardized Interconnection Procedures ("Smart Grid SGIP")

Specifications and Requirements for Electrical Installations ("Red Book")

Submetering Procedures ("Requirements for Residential Submetering")

Uniform Business Practices for Distributed Energy Resource Suppliers in the LIPA Service Territory (UBP-DERS-LIPA)

I. General Information (continued):**C. General Terms and Conditions (continued):****Net Metering of Community Distributed Generation (continued):**h) CDG Net Crediting Program

Effective January 1, 2021, a CDG Host that has all its CDG Satellites compensated pursuant to Section I.C.18 – Value of Distributed Resources (VDER) may participate in the CDG Net Crediting Program. The CDG Net Crediting Program is an elective payment and crediting methodology for CDG Hosts and CDG Satellites. Additional terms, conditions, definitions, and processes are set forth in PSEG Long Island’s Community Distributed Generation Net Crediting Manual and posted on the Manager’s website. In the event of any inconsistency between the PSEG Long Island’s Community Distributed Generation Net Crediting Manual and this Tariff, the Tariff will govern

The CDG Net Crediting Program allows Customers that are also CDG Satellites to receive a CDG Member Net Credit on their Electric Bill in lieu of receiving the CDG Member Full credit on their Electric Bill and then receiving an additional bill from the CDG Host. The Authority will remit a net payment to the CDG Host as described herein on behalf of our customers that are also CDG Satellites.

(1) Enrollment and Subsequent Changes

CDG projects participating in the CDG Net Crediting Program must meet all the requirements and follow the provisions provided within this Section.

The CDG Host must enroll in the program by executing a CDG Sponsor Net Crediting Agreement with the Authority, at least 60 days prior to commencing participation in the CDG Net Crediting Program, in addition to any other forms and registrations required under the CDG program as defined in this Section. Member participation in Net Crediting shall become effective with the first CDG Host bill sixty days after all necessary enrollment documentation have been received and approved by the Authority.

- (a) The CDG Host must be in good standing on the electric account tied to the CDG Host project to be eligible for and participate in Net Crediting. A CDG Host that fails to maintain its account in good standing may have its CDG Host Payments withheld.
- (b) CDG Hosts may remove a CDG project from the CDG Net Crediting Program with written notice to the Authority at least 45 days’ prior to the CDG Host Account’s cycle billing date to which the removal applies. A CDG project that has previously been removed from the CDG Net Crediting Program may only re-enroll after one year from the date they were removed from the CDG Net Crediting Program and will be subject to the required sixty days’ notice to re-enroll a CDG project as specified above.
- (c) If a CDG Host transfers ownership of a CDG project participating in the Net Crediting Program and the new CDG Host intends to continue the Net Crediting, the new CDG Host will be required to re-enroll the CDG project and meet all requirements including the sixty days’ notice as described here in.

I. General Information (continued):**C. General Terms and Conditions (continued):****Net Metering of Community Distributed Generation (continued):**(2) CDG Savings Rate

- (a) The CDG Host shall provide the value for the CDG Savings Rate for the project to the Authority as part of the enrollment process. Following the initial enrollment in the Net Crediting Program, the CDG Host may submit a notice to update the CDG Savings Rate no earlier than six months from the initial enrollment in the CDG Net Crediting Program or any subsequent date of modification to the Savings Rate.
- (i) The CDG Savings Rate may not be less than 5% for any CDG project and no greater than 99% (to leave room for the Administration Fee rate of 1%). The CDG Savings Rate will apply equally to all CDG Satellites of a CDG Project as specified in I.C.17.h).(4) below, except for an Excluded Anchor Satellite, if applicable,.
- (ii) The CDG Host may modify its CDG Savings Rate or its associated CDG Satellite accounts and/or the allocation percentages of its CDG Satellites, upon written notice to the Authority, no less than forty-five days prior to the CDG Host account's billing date to which the modifications apply.

(3) Anchor Satellite

- (a) The CDG Host may choose to designate one large CDG Satellite to be an Excluded Anchor Satellite.
- (b) The Excluded Anchor Satellite customer must have a demand greater than or equal to 25kW in the last twelve months.
- (c) The Excluded Anchor Satellites shall be identified on the CDG Net Credit Enrollment Form at least 60 days prior to net crediting as an Excluded Anchor Satellite.
- (d) The CDG Host may change the designation of the Excluded Anchor Satellite as set forth in the PSEG Long Island's Community Distributed Generation Net Crediting Manual.
- (e) The Authority shall not apply a Member Net Credit to the Excluded Anchor Satellite Bill.
- (f) The Authority shall not withhold a CDG Subscription Fee on the Excluded Anchor Satellite's allocated Value Stack Credits.

(4) Applied Credit and Subscription Fee

- (a) The Authority shall calculate and apply a Member Net Credit to each participating CDG Satellite's bill.
- (b) The Member Net Credit shall be determined as follows:
 - (i) For each billing period, the total credit allocated to the CDG Satellite shall be calculated pursuant to section I.C.18.c), Value Stack Calculation for net export injections made by the CDG Host. Banked Monetary Credits plus

allocated Monetary Credits applied to electric charges ("Applied Credit") cannot exceed the CDG Satellite's electric bill.

I. General Information (continued):**C. General Terms and Conditions (continued):****Net Metering of Community Distributed Generation (continued):**

- (ii) If there are remaining Monetary Credits, the credit shall be banked on the CDG Satellite's account for the subsequent billing period.
- (iii) The CDG's Satellite's Member Net Credit is equal to the Applied Credit times the CDG Savings Rate.
- (c) A CDG Subscription Fee will be calculated for all CDG Satellites, except the Excluded Anchor Customer, based on the Applied Credit each billing period. The CDG Subscription Fee is equal to the Applied Credit multiplied by one minus the CDG Savings Rate.
- (5) Each CDG Satellite, except for an Excluded Anchor Satellite, will receive a credit on its bill in the amount of the Member Net Credit for the billing period.
- (6) An Authority Administrative Fee is retained by the Authority and is equal to the Applied Credit times the 1% Administrative Fee rate for the billing period.
- (7) The CDG Host Payment will be the sum of the CDG Satellite's Subscription Fees calculated for each of the project's CDG Satellites in the applicable billing period less the Administrative Fee applicable for the billing period.
 - (a) The CDG Host Payment will be remitted to the each CDG Host in a separate payment via Automatic Clearing House (ACH) or check payment.
 - (b) If the CDG Host fails to pay any tariff charges on the CDG Host account for which a written bill has been rendered:
 - (i) After 30 days past due, the Company shall withhold the CDG Host payment until the CDG Host has provided payment of the full amount in arrears.
 - (ii) After 90 days past due, the Authority may remove the CDG Host from the CDG Net Crediting Program.
- (8) Unenrollment

CDG Hosts may unenroll from the CDG Net Crediting Program with 45 days' written notice to the Authority, in a manner pursuant to the PSEG Long Island's Community Distributed Generation 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 the date the unenrollment was fully completed and all Satellites were informed and billed.

Exhibit B-3 - RDM and DSA Tariff Redline

VIII.ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism**1. Purpose

The purpose of the Revenue Decoupling Mechanism is to recover approved Delivery Service Revenues from customers. Actual Delivery Service Revenues are reconciled to the approved Delivery Service Revenues through the Revenue Decoupling Mechanism for certain Service Classifications groups, as described below,

2. Definitions

For the purposes of the Revenue Decoupling Mechanism, the following Service Classification ~~g~~Groups will apply.

a) Residential

- (1) Service Classification No. 1 (Rate Codes: 180, 480, 481, 580)
- (2) Service Classification No. 1-VMRP (Rate Codes: 181,182,184,188)
- (3) Service Classification No. 16-AMI (Rate Code M188)

b) Small Commercial

- (1) Service Classification No. 2 (Rate Code 280)
- (2) Service Classification No. 2-VMRP (Rate Code 288)
- (3) Service Classification No. 16-AMI (Rate Code M288)

c) Large Commercial excluding mandatory demand metered service with multiple rate periods:

- (1) Service Classification No. 2-L (Rate Codes 281, 283, 291)
- (2) Service Classification No. 2L-VMRP (Rate Codes 282, M282)

d) Mandatory Large Demand Metered Service with Multiple Rate Periods

- (1) Service Classification No. 2-MRP (Rate Codes 284, 285, M284, M285)

ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism****Definitions (continue):**

- e) Retail Customers participating in the Long Island Choice or Green Choice program are subject to the Revenue Decoupling Mechanism according to their base rate Service Classification.
- f) The Revenue Decoupling Mechanism does not apply to:
 - (1) Energy Service Companies (ESCOs) receiving service under Service Classification No. 14.
 - (2) Service Classification Nos. 5, 7, 7A and 10 (Rate Codes 980, 780, 781, 782, 1580, 1581).
 - (3) Service Classification Nos. 11, 12, and 13 (Rate Codes 289, 680, 681, 278).
 - (4) All load delivered under the Empire Zone Program, Excelsior Jobs Program, Manufacturer's Competitiveness, Business Attraction/Expansion Program, Business Incubation, and Recharge New York Programs.
- g) Annual Approved Delivery Service Revenues subject to the Revenue Decoupling Mechanism are:

The Delivery Service Revenues approved by the Authority for each Service Classification for each month, starting on April 1st 2015. Delivery Service Revenues exclude adjustments to rates and charges, which include: the Power Supply Charge, Distributed Energy Resources Cost Recovery Rate, New York State Assessment Factor, Shoreham Property Tax Settlement Factor, Visual Benefits Assessment Rate, Charges to Recover PILOT Payments, the Revenue Decoupling Mechanism, and the Delivery Service Adjustment.
- h) Revenues for the calendar year are set forth in the approved LIPA budget, and are revised each December for the upcoming calendar year.
- i) Actual booked Delivery Service Revenues are, for the purposes of Revenue Decoupling Mechanism, booked revenues for all Service Classifications for each month in the calendar year as it relates to the Service Charge, Meter Charge, Demand Charge (per kW), Reactive Demand Charge (per kvar), the Energy Charge for delivery (per kWh).

ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism****3. Cost Recovery Period and Method**

a) For each Service Classification **g**Group subject to the Revenue Decoupling Mechanism:

(1) The difference between actual booked Delivery Service Revenues and approved Delivery Service Revenues will be reviewed monthly and accrued for refund to or recovery from the applicable Service Classification groups.

(2) After September 30th of each year, the cumulative revenue variance as of September 30th will be identified for each of the four participating Service Classification **g**Groups, and the refund or surcharge amount that is due to or from each of the four participating Service Classification groups will be calculated.

(3) For the calendar year beginning on January 1st, 2017 and each subsequent calendar year, the revenue variance estimated through December 31st of the coming year will be calculated and included in the refund or surcharge amount applied to the participating Service Classification **g**Groups.

a. The revenue variance for the coming year will be calculated based on the actual variance from the prior twelve (12) months at the time the Revenue Decoupling Mechanism is calculated.

b. In the event of a change to the Delivery Rates based on the implementation of a new sales forecast, which would mitigate the unknown variance in the coming year, subparagraph J.3.a).(3) may be fully or partially suspended as determined by the Authority.

(4) Any revenue variance associated with the actual booked Delivery Service Revenues of the non-participating customer load as noted in Section VII. J.2.f) and any revenue variance associated with actual booked revenues from low income discounts will be allocated proportionately to the four Service Classification **g**Groups participating in the Revenue Decoupling Mechanism based upon the actual booked Delivery Service Revenue for each Service Classification group during the twelve (12) months ending September 30th.

(5) The refund or surcharge amount for each Service Classification **g**Group will be divided by the forecasted Delivery Service Revenues for each Service Classification group for the upcoming calendar year to develop the percentage of Delivery Service Revenues for each Service Classification group.

(6) Beginning in 2017, the surcharges or refunds percentages will be applied, to the Delivery Service charges associated with each customer in the four participating Service Classification Groups, for the 12-month periods beginning January 1st of each calendar year.

ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:**J. Revenue Decoupling Mechanism
Cost Recovery Period and Method (continued)**

4. If at any time the balance due from or owed to customers exceeds \$20 million, the Authority Staff may adjust collection or refund of Revenue Decoupling Mechanism amounts prior to the onset of the next annual Revenue Decoupling Mechanism collection/refund period.
5. If in any Recovery Period the balance due from the Residential Service Classification Group exceeds an RDM percentage of 5%, the Authority will cap such percentage rate at 5% and defer the remaining balance for recovery to future periods.
6. If in any Recovery Period the balance due from any Commercial Service Classification Group exceeds an RDM percentage of 5%, the Authority will cap such percentage rate to 5% and re-allocate the remaining balance or a portion of the remaining balance to other Commercial Service Classification Groups and/or defer the remaining balance or portion of the remaining balance to future periods, as explained below.
 - a) If a Commercial Service Classification Group experienced a loss in the number of Customers equal to 5% or less from the budgeted number of Customers, the balance to be recovered that exceeds 5% will be deferred to future periods.
 - b) If any Commercial Service Classification Group experienced a loss in the number of Customers of more than 5% and exceeds the cap of 5%, revenue due to the loss of budgeted customers will be allocated pro-rata between all the Commercial Service Classification Groups. Any allocated balance that cannot be recovered from a Commercial Service Classification Group in that recovery period due to the 5% rate cap will be deferred to future periods from the same Commercial Service Classification Group to which it was allocated.
 - c) The revenue that will be subject to a reallocation to other commercial classes will equal the difference between the average number of customers presented in the budget as compared to the actual number of customers during the tracking period, multiplied by the average revenue per customer during the tracking period.

4.7. Statement of Revenue Decoupling Mechanism

The Revenue Decoupling Mechanism percentage amount to be refunded or surcharged to Customers will be shown for each of the four participating Service Classification groups and the effective date on the Statement of Revenue Decoupling Mechanism. The Authority will file such Statement for each annual collection/refund period, and the Statement will be available at the Authority's business offices.

**VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:
(continued):****K. Delivery Service Adjustment**1. Purpose and Applicability

The Delivery Service Adjustment is a rate mechanism that reconciles on an annual basis the difference between the amount of certain costs included in the Authority's base delivery rates ("Base Rate Costs") and the amount of such costs that the Authority actually incurs in an annual period.

2. Applicability

- a) The Delivery Service Adjustment will be assessed to Service Classification Nos. 1, 1-VMRP, 2, 2-VMRP, 2-L, 2-L-VMRP, 2-MRP, 5, 7, 7-A, 10, 12 and 16.
- b) Retail Customers participating in the Long Island Choice or Green Choice program are subject to the Delivery Service Adjustment as applied to their Service Classification.
- c) The Delivery Service Adjustment does not apply to:
 - (1) Energy Service Companies (ESCOs) receiving service under Service Classification No. 14.
 - (2) Service Classification Nos. 11 and 13 (Rate Codes 289, 278).
 - (3) All load delivered under the Empire Zone Program, Excelsior Jobs Program, Manufacturer's Competitiveness Business Attraction/Expansion Program, Business Incubation, and Recharge New York Programs.

3. Relevant Terms and Conditionsa) The Base Rate Costs subject to the Delivery Service Adjustment are as follows:

- (1) Storm Event Reserve Funding: Base Rate Costs include funding for a Storm Event Reserve. All Storm Event costs will be charged to the Storm Event Reserve. "Storm Events" are defined as set forth in the LIPA amended and restated, Operations Service Agreement ("OSA"), dated December 13, 2013. Storm preparation costs associated with storms that do not materialize may be recoverable through the Delivery Service Adjustment if a budget amendment recommending recovery of such costs is approved by the Authority Board of Trustees.

VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS:

(continued):

K. Delivery Service Adjustment**Relevant Terms and Conditions: (continued)**

- (2) Debt Service Costs: In accordance with the Department Rate Recommendation dated September 28, 2015, Base Rate Costs include the amount of interest and principal payments on the Authority's debt adjusted for amounts associated with its fixed coverage ratio, plus all amounts of interest and principal payments including coverage collected on behalf of the Utility Debt Securitization Authority (and any similar authority).
- (3) Non-Storm Emergency: Beginning January 2021, the incremental costs authorized by the Board of Trustees for Non-Storm Emergency Events as set forth in the LIPA amended and restated Operations Service Agreement ("OSA"), dated December 13, 2013, will be eligible for recovery. The recovery will be net of any anticipated reimbursements received from outside sources for that Non-Storm Emergency event or condition. Should the actual reimbursements vary from the anticipated reimbursements the difference will be added to subsequent tracking periods. Consistent with Section 5.2.B.7 of the OSA:
- i. The recovery will include the amount of the Budget Amendment approved by the Board for that budget year.
 - ii. The recovery will not include amounts for the expenditures that are designated for inclusion in future budget (contract) years.
 - iii. The materiality of the costs are considered as part of the determination to request and ultimate approval by the Board for a Budget Amendment to recover for Non-Storm Emergencies and will be included for recovery without further standards or requirements for materiality upon approval by the Board.
- (4) Bad Debt Expense: Beginning January 2021, any variance of accrued bad debt expense from the amount in an approved LIPA budget during periods affected by a government ordered or Board authorized moratorium on service disconnections and for up to 2 years following the end of such moratorium will be eligible for recovery.
- (2)(5) Service Provider Pension and Other Post-Employment Benefits (OPEB) Expense: Beginning January 2021, any variance from the amount in the Approved Annual Budget for pension and OPEB expenses related to the Service Providers operations excluding Pension and OPEB allocated to Capital, Storms or Utility 2.0 as they are tracked separately will be eligible for recovery.
- b. Tracking Period: ~~In 2016, the Tracking Period shall be the nine months, January 1, 2016 to September 30, 2016. After September 30, 2016, t~~The Tracking Periods shall be the twelve months beginning October 1 and ending September 30 of each year.
 - c. Storm Event Reserve Cap: The Storm Event Reserve Cap will be set to \$75 million and will be shown on the Statement of Delivery Service Adjustment.
 - d. The difference between the actual costs incurred by the Authority during the Tracking Period as identified in Section K. 3. a and the Base Rate Costs for the Tracking Period will determine the DSA recovery/credit amount as follows:
 - (1) The entire difference in Debt Service Costs, Bad Debt Expense, and Service Provider pension and OPEB expense related to operations will be included for recovery/crediting in the next Recovery Period as defined below.

(2) A cumulative balance will be established for the Storm Event Reserve. Starting in January 2016, the approved amount of revenue to be collected through base delivery charges to satisfy the Storm Event Reserve will be added to that balance monthly, and actual Storm Event expenditures throughout the Tracking Period will be deducted from the balance. The balance remaining in the account at the end of the Tracking Period will be determined. If a positive balance exists below the Storm Event Reserve Cap, the balance will remain in the Storm Event Reserve to offset future expenditures for Storm Events. If a negative balance exists, one-third of that balance will be recovered in the next Recovery Period as defined below and the remaining two-thirds of the balance will be eligible for recovery during a future Recovery Period.

~~(3) In the event that the balance in the Storm Event Reserve Fund exceeds the Storm Event Reserve Cap, the funds in excess of the Storm Event Reserve Cap will be used to offset future capital spending.~~

~~4. Cost Recovery Period and Method~~

~~a) For the Service Classifications subject to the Delivery Service Adjustment:~~

~~(1) The difference in costs for the applicable Tracking Period as determined in accordance with Section K.3.d), plus the costs incurred under the Amended and Restated Power Supply Agreement between National Grid Generation LLC and the Long Island Lighting Company d/b/a LIPA, and for the operation, maintenance, and property taxes of the Nine Mile Point 2 Nuclear Facility will be credited to or recovered from the Service Classifications subject to the Delivery Service Adjustment.~~

~~(2) A Delivery Service Adjustment refund or recovery will be determined and applied to customer bills for the 12-months beginning January 1st of each calendar year (the "Recovery Period") subsequent to the end of the Tracking Period.~~

VII. ADJUSTMENTS TO RATES AND CHARGES OF SERVICE CLASSIFICATIONS: (continued):**K. Delivery Service Adjustment****Cost Recovery Period and Method: (continued)**

- (3) In the event that the balance in the Storm Event Reserve Fund exceeds the Storm Event Reserve Cap, the funds in excess of the Storm Event Reserve Cap will be used to offset future capital spending.
- (4) Amounts to be recovered for the Non-Storm Emergency Events will be recovered in equal dollar installments over the three succeeding annual Cost Recovery Periods.

4. Cost Recovery Period and Method**a) For the Service Classifications subject to the Delivery Service Adjustment:**

- (1) The difference in costs for the applicable Tracking Period as determined in accordance with Section K.3.d), plus the costs incurred under the Amended and Restated Power Supply Agreement between National Grid Generation LLC and the Long Island Lighting Company d/b/a LIPA, and for the operation, maintenance, and property taxes of the Nine Mile Point 2 Nuclear Facility will be credited to or recovered from the Service Classifications subject to the Delivery Service Adjustment.
- (2) A Delivery Service Adjustment refund or recovery will be determined and applied to customer bills for the 12-months beginning January 1st of each calendar year (the "Recovery Period") subsequent to the end of the Tracking Period.
- (3) To determine the Delivery Service Adjustment recovery or refund, the total Delivery Service Adjustment refund or recovery amount will be divided by the applicable forecasted Delivery Service Revenues for the Recovery Period to develop the Delivery Service Adjustment Percentage of Delivery Service Revenues.
- (4) The Delivery Service Adjustment will be included in each applicable customer's bill in an amount equal to the customer's delivery charges times the Delivery Service Adjustment Percentage of Delivery Service Revenues, rounded to the nearest cent, in each month of the Recovery Period.
- (5) Under or over recoveries of the Delivery Service Adjustment from prior Recovery Periods will be accrued at the end of each Recovery Period for refund or recovery through the Delivery Service Adjustment in a subsequent Recovery Period.

5. Statement of Delivery Service Adjustment

The calculation of the Delivery Service Adjustment Percentage of Delivery Service Revenues and the effective date will be shown on the Statement of Delivery Service Adjustment. The Authority will file such Statement annually, and the Statement will be available at the Authority's business offices.

Exhibit B-4 - Rental Property Data Access Tariff Redline

IV. Billing Process and Payment of Bills (continued):**C. Charges for Miscellaneous Services (continued):****10. Meter Reading Historical Information:**

- a) Customers, ESCO's and DRC's may request and will be provided, if available, up to twenty-four (24) months of monthly or bi-monthly historical meter reading information without charge. Monthly or bi-monthly historical meter reading information for historical periods beyond the twenty-four (24) months will be provided, as available, for a charge of forty dollars (\$40.00) regardless of the number of months of information requested or provided. Hourly or fifteen (15) minute interval data covering any historical monthly period will be provided, if available, at a charge of ten dollars (\$10.00) for each meter reading period's requested data.
- b) Customers who request their remote AMI meter reading data to be provided to them on a monthly basis will individually enter into a negotiated price agreement with the Authority.

AMI customers can retrieve all available meter data from the Manager's Website at no charge. Where available AMI will be used to collect meter data and measure net electricity transactions.

- c) Upon written request from a prospective tenant or lessee, the Authority will provide, at no cost, the total electricity charges incurred at the prospective residential rental premises for the life of the premises, or the preceding two-year period, whichever is shorter. Prior to the commencement of the tenancy or execution of a lease, the Manager will provide such information to the landlord or lessor and to the prospective tenant, or other authorized person, within ten days of receipt of the written request. The written request needs to include an email address where the requested data can be sent.

11. Metering Related AMI Charges:

- a) Residential Service Classification No.1 Customers (rates 180, 480, 481, 580) who are eligible to opt-out from installation of a smart meter (see Section III.E.5) but did not opt-out until after installation will be subject to a one-time fee ("One Time Meter Removal Fee") as per the Statement of AMI Smart Meter Fees.
- b) Beginning January 1, 2023, customers who have opted out of receiving an AMI equipped smart meter will be subject to a daily opt-out fee ("AMI Smart Meter Daily Opt-Out Fee") as per the Statement of AMI Smart Meter Fees.

Exhibit C - DPS Letter of Recommendation



Department of Public Service

Public Service Commission

John B. Rhodes
Chair and
Chief Executive Officer

Three Empire State Plaza, Albany, NY 12223-1350
www.dps.ny.gov

Diane X. Burman
James S. Alesi
Tracey A. Edwards
John B. Howard
Commissioners

December 4, 2020

Via Email and U.S. Mail

Honorable Ralph V. Suozzi, Chairman
Board of Trustees
Long Island Power Authority
333 Earle Ovington Blvd.
Uniondale, New York 11553
boardoftrustees@lipower.org

Re: Matter No. 20-00587 - Recommendations Regarding Long Island Power Authority's Proposed Modifications to its Tariff for Electric Service

Dear Chairman Suozzi:

I am pleased to provide the recommendations of the New York State Department of Public Service (DPS or the Department) regarding the Long Island Power Authority's (LIPA or the Authority) proposed modifications to its Tariff for Electric Service (Tariff), effective on various dates in 2021. The LIPA Reform Act (LRA) authorizes the Department to make recommendations regarding the operations and terms and conditions of service provided by the Authority and its Service Provider. The Department supports the Authority's proposals in accordance with the discussion set forth herein.

LIPA proposes a number of modifications to its Tariff for Electric Service. These include tariff changes: 1) to add four residential time-of-use (TOU) rates and one small commercial TOU rate, effective February 1, 2021 in accordance with its 2017 Utility 2.0 Filing; 2) to adjust the Revenue Decoupling Mechanism (RDM) and the Delivery Service Adjustment (DSA) to mitigate future customer bill volatility, effective January 1, 2021; 3) to implement Community Distributed Generation (CDG) net crediting, a billing option through which CDG Hosts may allow their CDG Satellites¹ to receive a single consolidated bill from PSEG Long Island, effective January 1, 2021; and 4) to implement the provisions of Public Service Law (PSL) §66-p, to allow landlords and prospective tenants access to the energy usage data of a rental property.²

¹ A CDG Satellite is an electric distribution customer taking service under the Tariff who is allocated Value Stack Credits from its CDG Host in accordance with the CDG Net Crediting Tariffs: A CDG Satellite is also referred to as a CDG Subscriber.

² Effective April 18, 2020.

Time-of-Use Rates

LIPA proposes to add four TOU Residential Rates and one TOU Small Commercial Rate to its Tariff. These rates offer choices of shorter peak periods over three to four hours versus current residential and small commercial TOU rate offerings which have a 10-hour peak period. The shorter peak period will empower customers to more easily shift their energy use to off-peak times. The Department recommends the proposal be adopted as discussed herein.

Three of the four proposed residential TOU rates, and the single small commercial TOU rate, have three separate daily periods that include: (1) Peak; (2) Off-peak; and (3) Super Off-peak. The proposed three-period TOU rates also span three pricing seasons: (1) Summer; (2) Spring and Fall (shoulder); and (3) Winter. In addition to seasonal pricing, the rates also have separate pricing for both Energy and Power Supply.

The fourth residential TOU rate has two daily periods: (1) Daytime and (2) Nighttime. In its initial filing, no seasonal differences were proposed for this rate option. Upon consultation and comment by the Department, LIPA agreed to modify this option to include a seasonal differential. Including a seasonal differential is consistent with the Department's Rate Recommendation in Matter 15-00262.³ As stated in the Department's Rate Recommendation, "seasonal rates are designed to further two important regulatory goals: to promote conservation and to align rates to the extent practicable with the cost drivers. For LIPA, summer peak load is a primary factor in Transmission and Distribution (T&D) facilities design and construction."⁴ Inclusion of a seasonal differential furthers these goals and maintains alignment between LIPA's rates and their underlying cost drivers. Upon consultation with DPS, LIPA, revised the proposal to include a seasonal differential. DPS staff has reviewed the revised rate proposal and finds it is consistent with modification discussed above.

Each of these new time-of-use rate codes are described in the table below:

Rate Code	Peak	Super Off-Peak	Off-Peak
Res 190 (Short Peak)	4 PM to 7 PM, Mon-Fri	10 PM to 6 AM	All other hours
Res 191 (Late Peak)	4 PM to 8 PM, Mon-Fri	11 PM to 7 AM	All other hours
Res 192 (Early Peak)	3 PM to 7 PM, Mon-Fri	10 PM to 6 AM	All other hours
Res 193 (Day/Night)	6 AM to 11 PM	11 PM to 6 AM	n/a

³ Matter 15-00262, In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC, Department Rate Recommendation (issued September 28, 2015) pp. 160-166.

⁴ Id., p. 163.

Rate Code	Peak	Super Off-Peak	Off-Peak
Small Com 292	3 PM to 7 PM, Mon-Fri	11 PM to 6 AM	All other hours

Power Supply Charge

LIPA’s proposed TOU rates time-differentiate both the Delivery Service Charge and the Power Supply Charge between the peak and off-peak periods. The Power Supply Charge is time-differentiated for each of the proposed new rate codes using a multiplier against the standard non-time-differentiated Power Supply Charge. In each month, as the Power Supply Charge is updated, the single cents per kWh charge will be multiplied by the factors shown in the table below to create the time-differentiated charges for the peak, off-peak, and super off-peak periods. The factors in the table below will be updated each budget year based on the most recent load research profiles for residential Rate Code 180 and small commercial Rate Code 280.

Rate Code	Peak	Off-Peak	Super Off-Peak
190	199%	100%	60%
191	169%	100%	60%
192	177%	100%	60%
193	112%	60%	n/a
292	161%	100%	60%

The factors differ by rate code to reflect the different hours in each period and are calculated to recover the same annual total power supply costs that the average Rate Code 180 customer would have paid under the non-time-differentiated Power Supply Charge. The factors remain the same for every month of the budget year. DPS recommends that the LIPA Board of Trustees adopt these factors as part of the TOU proposal.

Other Tariff Changes Related to TOU Proposal

LIPA also proposes to modify its Tariff to close existing Service Classification No. 1 – VMRP (L) and Service Classification No. 1 – VMRP (S), effective January 1, 2025.⁵ Customers on these rates will be encouraged to transition to the rates under proposed Service Classification No. 1 – VTOU. New customers have been prohibited from enrolling in these rate classes beginning January 1, 2019.

All of the newly proposed residential TOU rates are based on load research information for the standard residential rate (Rate Code 180), which is appropriate for the vast majority of

⁵ Service Classification includes large residential time-of-use customers who use more than 39,000 kWhrs annually or more than 12,600 kWhrs during the four summer months. Large Residential TOU rate codes include Rate Code 181 (Large Non-Space Heat), Rate Code 182 (Large Space Heat), Rate Code 184 (Large Residential Space and Non-Space). Small residential customers, using less than large customers, are served under Rate Code 188.

residential customers, however, the proposed rates do not recognize differences in load research information for large residential space heating customers served under Rate Code 182. PSEG LI stated in consultation with DPS staff that it is considering a residential TOU space heating rate as part of Utility 2.0 in future filings. Until the Department has reviewed a proposal for a residential TOU space heating rate(s), the Department recommends that existing space heat service customers continue to be served under Rate Code 182 until the later of (1) January 1, 2025 or (2) the 1-year anniversary of the LIPA Board of Trustees' approval of a new TOU space heating rate. Transitioning customers from Rate Code 182 should occur only when the impact of such an action on customers, based on the structure of the new rate, can be assessed. It is important for customers to have all the necessary information to transition to a new rate, especially, if the rates under which they are currently served are eliminated before an alternative becomes available. In addition to an available alternative rate structure, it is important for customers to have adequate usage data to complete a bill comparison to their current rate. Without an alternate bill structure in combination with personal consumption data, and the MY ACCOUNT tool, customers would have a more difficult time choosing the best option for themselves.

LIPA and PSEG LI also propose to discontinue new customer enrollment in the existing off-peak energy storage rates (Rate Codes 480 and 481) beginning January 1, 2021 and to transition customers off of and close these rates entirely beginning January 1, 2025. LIPA states that the newly proposed TOU rates are more beneficial to customers seeking to save money by shifting their energy use to nighttime. Customers who are currently on Rates 480 and 481 will be able to remain on these rates until December 31, 2024. The Department recommends that the proposal to modify Rates 480 and 481, be adopted as proposed. DPS staff notes that the super off-peak rates available under the proposed TOU rates compare favorably to existing energy storage rates.

Currently, off-peak energy storage consumption is separately metered from a customer's residential or house load via internal wiring. When customers transition to other rate offerings, they will be required to rewire their storage load to the house meter. PSEG Long Island stated in consultation with DPS staff that customers will be reimbursed for the rewiring through a rebate like process if they are required to be removed from the current storage rate.

The new TOU rates will require new Net Metering banking rules. LIPA proposes to add rules to the Net Metering tariff, such that a customer who switches from a rate with one rate period to a rate with multiple rate periods will transfer all billing credits to the off-peak period, as this period is equal to the standard rate. To allow the tariff to address the reverse situation, customers who move from multiple rate periods to one rate period, will have all credits consolidated to the standard rate bank. Although the proposed tariff modifications address the transfer of banked net metering credits for non-TOU customers who transition to TOU rates, and for TOU customers who transition to non-TOU rates, it does not address banking credits to be transferred from existing TOU rates to the newly proposed TOU rates. The Department recommends that LIPA modify the tariff in the future, to include language addressing net metering transfers from one TOU rate to another.

Because the newly proposed TOU rates differ from existing TOU rates, specifically, the difference in the rate applied to the individual daily periods, DPS recommends that the kWh credits under existing TOU rates be converted to an equivalent monetary net metering value. The resulting monetary credit would then be converted back into the new off-peak energy (kWh) credit using the appropriate unit off-peak rate. Tariff language concerning the reverse is not needed because transfer back to existing TOU rates is foreclosed by LIPA's proposed tariff modifications.

In its Tariff proposal document, LIPA states that no substantial revenue impacts are expected to result from the proposed TOU rates, as any reduction in revenue, will be recovered in the Revenue Decoupling Mechanism⁶. Further, the financial impact to any particular customer will depend on the customer's ability and willingness to reduce usage during the peak period. PSEG Long Island estimates that a customer who shifts 6% of peak energy usage to off-peak times would experience delivery bill savings of between \$36 and \$45 annually. A customer who shifts 8% of peak usage would save between \$49 and \$60 annually, and a customer who shifts 10% of peak usage would save between \$62 and \$75 annually.

In addition, customers who install battery energy storage systems may save significantly more by charging their battery systems during the overnight super off-peak period and injecting energy into the grid during the peak period. PSEG Long Island notes that under a customer's MyAccount portal on the PSEG LI website, features are available, that will assist individual customers in estimating the potential bill impact of switching to one of the proposed TOU rates.

Customers, whose lifestyles tend to preclude peak usage, may also benefit from this new TOU rate structure. For example, customers who work and are away from home during peak hours can shift some of their peak air-conditioning load in summer months to less expensive off-peak hours, by pre-cooling their house before the onset of the on-peak period.

Properly designed TOU rates, that offer relatively short on-peak periods in combination with a large differential between peak and off-peak/super off-peak rates, like those being proposed by LIPA, give customers both the incentive and the opportunity to make changes to achieve bill savings and are expected to result in increased customer satisfaction. For these reasons, the Department recommends that the TOU Rate proposal be adopted as discussed above.

Revenue Decoupling Mechanism and Delivery Service Adjustment Modification

LIPA proposes to modify the Tariff to limit the RDM rate to a maximum of 5% of delivery service revenues for any customer class and to modify the DSA to allow for recovery of additional expenses related to Non-Storm Emergencies, Bad-Debt and pensions and Other Post-Employment Benefits (OPEBs), to limit future volatility of LIPA's rates. The Department

⁶ Proposal Concerning Modifications to LIPA's Tariff for Electric Service Requested Action to modify the Tariff for Electric Service (the "Tariff") effective February 1, 2021, in accordance with the 2017 Utility 2.0 Filing and the subsequent filing updates to add four residential time-of-use ("TOU") rates and one small commercial TOU rate, p. 5.

recommends adoption of the RDM as proposed, and the DSA proposal with modification as discussed herein.

Revenue Decoupling Mechanism Modification

LIPA's proposes to limit the rate impact of the RDM, for any customer class, to a maximum of 5%. Further, LIPA proposes that if there is a decrease of greater than 5% in the number of customers in any given commercial class, the impact from such a decrease, be reallocated to all other commercial classes up to the 5% maximum established for all customer classes. The Department supports the proposed cap to limit the impact on customer revenues, and thereby customer rates, and DPS staff notes that future revenue impacts can be mitigated through changes in class forecasted sales that result from changes in economic circumstances in the annual budget and rate update process.

LIPA states that the RDM 5% cap proposal will have no long-term financial impact to LIPA. Revenues that would have been collected through the current year's RDM will either be deferred to future years or be shared among other classes in the same year. Customers will benefit from the cap financially, as this will reduce impacts to their current bills. The 5% cap will amortize over time, the impact of any volatility due to emergencies such as the current COVID-19 pandemic. The Department recommends that the RDM proposal be adopted as proposed.

Delivery Service Adjustment Mechanism Generally

LIPA proposes to adjust the DSA to reconcile, and collect or return, variances in expenditures related to Non-Storm Emergencies provided for in the Amended and Restated Operating Services Agreement (A&R OSA), net of any anticipated reimbursements from outside sources during a non-storm emergency event or condition.⁷ LIPA also proposes to modify the DSA, to collect or return, variances in expenses related to Bad-Debt, pensions, and OPEBs. The Department recommends the proposed changes to the DSA be adopted with modifications.

In 2015, as part of the initial three-year rate proposal LIPA and PSEG Long Island proposed the DSA as a cost recovery mechanism for certain delivery rate components which LIPA and PSEG Long Island assert are outside their control, specifically Debt Service costs; Power Supply Agreement (PSA) or LIPA-owned generation costs;⁸ and Storm Costs. LIPA's proposed update to the DSA tariff would add expenditures related to variances in Non-Storm Emergencies, Bad-Debt, pensions and Other Post-Employment Benefits (OPEBs) to the DSA for reconciliation, and collection or return, from or to customers.

LIPA's proposed modifications to the DSA are based on cost components that are subject to volatility outside of LIPA's or PSEG Long Island's control. Reconciling these costs through the DSA will enable LIPA to manage the uncertainty of costs that can ultimately result in higher

⁷ See, A&R OSA §5.2 (B)(7), Non-Storm Emergencies.

⁸ This component of the DSA was amended and is no longer included in the DSA.

rates for customers if left unmanaged. The proposed modifications to the DSA ensure that customers do not pay a higher cost than warranted.

Non-Storm Emergency Expenses

The A&R OSA defines a non-storm emergency as an event or condition, other than a Storm Event, that is beyond the reasonable control of LIPA and for which the LIPA Board of Trustees determines certain non-budgeted expenditures to be required in order for LIPA to provide safe and reliable service. LIPA proposes incremental costs related to a non-storm state of emergency be recovered in the DSA, to the extent these costs are not reimbursable by the Federal Emergency Management Agency (FEMA). Should anticipated reimbursements not come to fruition they will be added to subsequent tracking periods. Amounts to be recovered for the Non-Storm Emergency Events will be recovered in equal dollar installments over the three succeeding annual Cost Recovery Period. The Department recommends the proposal be adopted as discussed herein.

LIPA, PSEG Long Island and DPS recognize that these non-Storm Emergency costs must be extraordinary and infrequent in nature and therefore these costs are not budgeted by LIPA. Costs will be included in the DSA only if a budget amendment is requested by PSEG LI, pursuant to its contractual right and approved by the LIPA Board of Trustees. PSEG Long Island is also required to meet materiality thresholds, regarding operating expenses before requesting approval from LIPA. Therefore, the DSA acts as a cost recovery mechanism to recover these costs once they have met the necessity and materiality thresholds for approval by LIPA through a budget amendment.

The Department also recommends that LIPA provide these costs to DPS for review prior to the budget amendment request to the LIPA Board of Trustees approval to recover these costs from customers through the DSA. To the extent significant costs or non-storm emergency periods persist, the Department recommends that LIPA and PSEG LI submit the Non-Storm Emergency Expenses to DPS, annually so that the Department may review and make recommendations, as may be appropriate. The Department recommends that the proposal be adopted as discussed above.

Bad Debt Expenses

LIPA proposes to adjust the DSA to capture variances in annual bad debt expense. LIPA states that bad debt expense is beyond its control due to the moratorium on customer terminations in effect due to the ongoing pandemic, and in the event that the bad debt expense is different from the budgeted amount, this will be recovered from or returned to customers, through the DSA, in the following year. The Department recommends that the proposal be adopted as discussed herein.

DPS staff notes that the current moratorium on customer termination and disconnection of customers and corresponding regulatory changes in NY State Laws to address COVID-19 has

put upward pressure on these expenses.⁹ In order to mitigate the impact on ratepayers and for LIPA and PSEG Long Island to continue to effectively manage these expenses, the Department recommends that LIPA reconcile bad debt expense through the DSA for a period not exceeding two years following the end of that moratorium.

The Department recommends, that subsequent to that time period, LIPA only reconcile bad debt expense through the DSA for periods of time not to exceed two years following the end of period(s) in which a change in law, rules or customary practice, suspends customer terminations or disconnections, result in a LIPA Board of Trustees' authorized moratorium on customer terminations.

Pension and Other Post-Employment Benefits (OPEBs) Expenses

LIPA proposes, to reconcile through the DSA, expenditures related to O&M pensions and OPEBs from the amounts included in the annual budget. At the end of each calendar year, the actual audited cost for O&M pensions and OPEBs, will be compared to the amount approved by the LIPA Board of Trustees in the annual budget and the variance will be included in the DSA for recovery in the following year. The Department recommends the proposal be adopted as proposed.

Pension costs related to operations are included in LIPA's revenue requirements and rates. These pension costs are estimated in accordance with U.S. Generally Accepted Accounting Principles (GAAP) by a third-party actuary. The estimated pension costs used to calculate the revenue requirements and rates are based on reports received by the actuary. The estimated amount included in rates will be compared to the actual pension expenses experienced and the difference will be subject to recovery/refund through the DSA.

OPEB obligations, on the other hand, are currently not recovered directly through revenue requirements but funded from cash that was included as coverage in the revenue requirements and rates. LIPA makes contributions each year to its internally managed OPEB account to pre-fund the future OPEB obligations to PSEG Long Island employees currently providing services to LIPA. Similar to pensions, the estimated amount included in rates will be compared to the actual OPEBs expenses and recovered through the DSA. This amount recovered through the DSA will be contributed to the OPEB account, in addition to the amount that was intended to be contributed in the approved budget from coverage. To the extent that the OPEB expense recovered through the DSA is negative, the annual contribution to the OPEB account will be reduced by that same amount.

The Department notes that LIPA's proposal would align with the reconciliation mechanisms authorized by the Department for Investor Owned Utilities (IOUs). The Pension/OPEB Policy Statement allows the reconciliation of actual pension and OPEBs expenses

⁹ New York State's "State of Emergency" Executive Orders issued by Governor Andrew M. Cuomo on March 7, 2020, and the PSL amendment signed by the governor on June 17, 2020 that ordered a moratorium on terminations and disconnections of residential electricity, gas, steam, telephone, and water customers during the COVID-19 state of emergency.

to the level allowed in rates.¹⁰ LIPA, PSEG Long Island and its actuary are unable to predict with certainty the annual accrual for pension and OPEBs, that should be recovered from customers, until after the finalization of the annual budget. LIPA's proposal would reconcile the O&M budget estimates of pension and OPEBs (which are estimated by an actuary approximately August of the prior year) to the amount actually accrued during the year, which is not known until approximately February of the following year. Interest rates and other factors outside of LIPA's and PSEG Long Island's control add to the volatility of these expenses and impacts LIPA's ability to maintain an appropriate fixed coverage ratio. As such, the Department recommends the proposal be adopted as proposed.

Community Distributed Generation Net Crediting

LIPA proposes to implement CDG Net Crediting for Value Stack CDG Hosts, consistent with the Commission's guidance and requirements under the Net Crediting Order.¹¹ LIPA's proposal will enable CDG satellite accounts to receive one bill from PSEG LI which will include their CDG allocated credit, less their CDG Subscription Fee, as described below. The Authority will pay the CDG Host its subscription fee less a 1% administration fee retained by the Authority. The Department recommends this proposal be adopted as proposed.

On July 17, 2015 and October 16, 2015, the Commission issued Orders in Case 15-E-0082, setting forth policies, requirements and conditions for implementation of CDG by New York's IOUs.¹² A CDG program is comprised of three main parties: the CDG Host (Host); CDG Satellites (Satellite); and the Utility, in this case LIPA and PSEG Long Island. A Host is the project sponsor and is responsible for owning or operating the generation facility, coordinating a project's interconnection and operation with LIPA and PSEG Long Island, and managing cooperation among the project's Satellites. Satellites are project subscribers; they receive credits accumulated at the generation facility's meter, as a percentage of the generation facility's output in excess of usage on the Host's account. LIPA and PSEG Long Island will be responsible for distributing the credits from the Host's account on Satellite customers' bills in accordance with the Host's instructions.

On December 12, 2019, the Commission issued its Net Crediting Order which established the policies, requirements and conditions to implement Net Crediting. Currently, each Satellite customer subject to Value Stack crediting receives a credit on its electric bill for its proportionate

¹⁰ Case 91-M-0890, In the Matter of the development of a Statement of Policy concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pension and Postretirement Benefits Other Than Pensions (issued September 7, 1993) (Pension/OPEB Policy Statement).

¹¹ Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources, Order Regarding Consolidated Billing for Community Distributed Generation (issued December 12, 2019) (Net Crediting Order).

¹² See, 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 Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015); Order Granting Reconsideration in Part (issued October 16, 2015).

share of the Value Stack credits generated by the Host. The Host separately bills each satellite for its subscription fee. Under the Net Crediting Order, subscription fees are deducted from the renewable energy credits by the Authority and are sent to the Host, based on a percentage set by the Host.

CDG Hosts will be allowed to enroll in the net crediting program as long as all Satellites are compensated under Value Stack crediting. All Satellites, with the exception of one, “Anchor Satellite,” who will be required to have the same savings rate, will receive a percentage of savings which the customer will retain.¹³ The savings rate will be set to a minimum 5% of the per kWh Value stack credit.

A CDG Satellite’s Applied Credit will be calculated for each billing period, pursuant to the CDG Net Crediting Tariff, and will equal the portion of the Total Available Credit that offsets the CDG Satellite’s Electric Bill in the billing period. A CDG Satellite’s Applied Credit cannot exceed the amount of a CDG Satellite’s Electric Bill during an individual billing period. LIPA will use the Applied Credit as the basis with which to determine the CDG Subscription Fee. LIPA will then provide each CDG Satellite with the net credit on the CDG Satellite’s Electric Bill.

The CDG Host can exclude one Anchor Satellite from the program when, without significantly increasing the implementation timeline or costs if all other customers are included in a net crediting arrangement.”¹⁴ LIPA will multiply the total Value Stack Credit of the CDG Host by the percentage allocated to the Anchor Satellite (not to exceed 40%) and include that amount of credit to the Anchor Satellite’s account in the month. The CDG Host will separately bill the Anchor Satellite for any subscription fees applicable to that Anchor satellite according to their separate agreement.

A CDG Subscription Fee will then be calculated based each CDG Satellite’s Applied Credit in each billing period. The CDG Subscription Fee is equal to the amount of the Applied Credit multiplied by a percentage equal to one minus the CDG Savings Rate. (e.g. if the savings rate is 5% the CDG Subscription Fee will equal 1 minus .05, or 95%). LIPA will pay the CDG Host for the total Subscription Fee of the satellites in the project, less a one percent (1%) administrative fee that is retained by LIPA.

DPS staff also reviewed the rules of the CDG Net Crediting program, submitted in a supplemental document to the Tariff, entitled, “PSEG Long Island’s Community Distributed Generation (CDG) Net Crediting Manual.” The rules adopted under the Manual are consistent with New York IOU’s rules.

LIPA states that there are no anticipated financial impacts for this proposal. The amount of credit received by the participating satellite customers is deducted from the payments that

¹³ An “Anchor Satellite” is a large commercial customer that anchors the project by taking a significant share of the output of the Host facility ($\leq 40\%$) and paying a large share of the facility’s costs directly to the CDG Host.

¹⁴ Net Crediting Order, p. 14.

would have been given to the CDG Host, and the one percent (1%) Administrative Fee withheld from the CDG Host payments is expected to compensate LIPA for the cost to administer this program. As such, the Department recommends that the proposal be adopted as proposed.

Public Service Law §66-p

LIPA proposes to modify the Tariff for Electric Service to be consistent with the new provision, PSL §66-p of Public Service Law. Public Service Law §66-p will allow for potential lessee, potential tenant, or the current landlord to request, in writing, the total electric charges monthly or bi-monthly that are incurred for either the life of the subject property or the previous two years, whichever is shorter. This requested information will be provided to the requesting party free of charge. The Department has reviewed the proposed Tariff and finds that it is consistent with Public Service Law §66-p and in accord with New York IOU tariffs. The Department recommends the proposal be adopted as proposed.

Conclusion

The Department has reviewed LIPA's proposals and finds the Tariff modifications consistent with Commission Orders, DPS staff Whitepapers, and New York IOU Tariffs. The Department, therefore, recommends that, in accordance with the foregoing discussion and recommended changes, the Tariff modifications be adopted by the LIPA Board of Trustees.

Respectfully submitted,



John Rhodes
CEO

CC: Thomas Falcone, LIPA Chief Executive Officer
Anna Chacko, LIPA General Counsel
Bobbi O'Connor, LIPA Secretary to the LIPA Board of Trustees
Justin Bell, LIPA VP of Public Policy and Regulatory Affairs
Daniel Eichhorn, PSEG LI President and Chief Operating Officer
Guy Mazza, DPS LI Director

Exhibit D - Transcripts of Public Comment Sessions

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LONG ISLAND POWER AUTHORITY

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VIRTUAL ZOOM

TARIFF

PUBLIC COMMENT SESSION

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November 18, 2020

2:03 P.M.

B e f o r e :

JUSTIN BELL,

Director of Rates and Regulations

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A P P E A R A N C E S :

FROM LIPA

Justin Bell

Director of Rates and Regulations 3

Tamela Monroe

LIPA CFO 5

Adam Cohen

ninedotenergy 18

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P R O C E E D I N G S

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MR. BELL: Good morning -- or rather good afternoon, everyone.

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And welcome to today's public comment session.

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My name is Justin Bell and I'm here today on behalf of LIPA.

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I'm also joined by Tamela Monroe, LIPA's CFO.

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The purpose of this session is to receive public comments on LIPA's proposed 2021 budget and a set of proposals to modify LIPA's tariff for electric service.

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The proposed budget is available on the main landing page of LIPA's website and the tariff proposals are available on our proposed rule making page. They are incorporated into the record of this hearing.

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In a moment, I will turn it over to Tamela for a brief presentation on the 2021 budget and then I will briefly summarize the tariff proposals.

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After the presentations, we will call the names of members of the public who have

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2 signed up to make comments. If you want to speak
3 but haven't yet signed up, please send an e-mail to
4 tariffchanges@lipower.org, indicating your name,
5 the organization that you're speaking on behalf of,
6 if any, and whether you'll be speaking at today's
7 session or tomorrow's session. You may also use
8 the chat feature of go to meetings and indicate
9 your desire to speak.

10 When you're called to speak,
11 please start by unmuting your phone or computer.

12 A full transcript of your comments
13 will be provided to LIPA's Board of Trustees for
14 their consideration prior to the next board meeting
15 when they will be voting on these items.

16 Your comments will also be
17 provided to the Department of Public Service, the
18 LIPA staff and to PSEG Long Island for their review
19 and consideration.

20 Please note that today's session
21 is being recorded.

22 As the purpose of this hearing is
23 to receive your comments, we will not be responding
24 to the comments and questions at the hearing today.
25 However, comments or questions may also be sent in

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2 writing to the same e-mail address I just provided,
3 tariffchanges@lipower.org.

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And written comments should be
5 received by December 1st in order to ensure that
6 staff has sufficient time to incorporate them into
7 the briefing materials for the board. However,
8 comments may be sent at any time and will be
9 provided to the board in any event, even if you're
10 later than that date.

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So I will now turn it over to
12 Tamela to provide a brief summary of the proposed
13 budget.

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MS. MONROE: Good afternoon,
15 everyone.

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Thank you for joining us this
17 afternoon.

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So our strategy around developing
19 our work in the supporting budget is to be clean,
20 lean and customer first. And I think you will see
21 that throughout our 2021 budget presentation.

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The next slide, I'd like to take a
23 minute to explain the environment in which we
24 started to give the development of the 2021 budget.

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As soon as the pandemic -- the

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2 impact of the pandemic became apparent, we looked
3 at developing measures, not only for 2020 but
4 across the next three years as we understood the
5 impact could be prolonged for our customers.

6 I wanted to also mention that the
7 measures you see on this slide, did not adversely
8 impact reliability or the ability to deliver
9 electric service to our customers. It merely
10 defers capital projects or good projects that we
11 have put the cost of those on hold until after
12 2023.

13 Next slide, please.

14 Now our strategy to be lean is
15 seen throughout the whole budget process. This
16 slide provides the list of cost savings from lean
17 efforts. It totals \$718 million in 2021. That
18 equates to approximately \$32 per month of savings
19 for an average residential customer.

20 Next slide, please.

21 The 2020 budget has two
22 components; on the left side, you'll see the
23 operating budget, which is \$3.72 billion. \$3.66
24 billion of that -- the total budget, will be
25 collected from our customers through rates and

1

2 tariffs.

3

4 And \$58.7 million will be received

5

6 In the middle on the left, you'll
7 see the cost categories and the amounts and the
8 breakdown of that budget. On the right side is the
9 2021 capital budget request is \$766 million. The
10 capital improvements in the system are \$671 million
11 with an additional \$94 million for storm hardening
12 in 2021.

12

Next slide, please.

13

14 Now here's some additional detail
15 from the operating budget. This slide compares the
16 2020 budget with the 2021 proposed budget.

16

17 The first thing to note is the
18 total requested budget is lower than the 2020
19 budget by \$4.8 million.

19

20 Starting on the left, we have the
21 2020 approved budget, which was \$3.666 billion.
22 And on the right side is the 2021 proposed
23 operating budgets to be collected from customers
24 and that is \$3.662 billion.

24

25 In the middle you can see the
increases and decreases by cost categories. The

1

2 largest increase component is the debt service
3 payments for LIPA and the UDSA debt, which is \$23
4 million.

5

The largest decrease is in power
6 supply costs. They are projected to decrease by
7 \$69 million, or about four percent.

8

Next slide, please.

9

Turning to the other portion of
10 the budget, which is the capital, the total capital
11 proposed budget is \$766 million, which is \$36
12 million less than 2020. The largest changes in the
13 regulatory projects, this is the completion of the
14 Western Nassau Transmission Project in 2021 and the
15 level of regulatory driven capital projects
16 significantly reduced because of that by
17 approximately \$95 million.

18

Local projects are always of an
19 interest in the community. In 2021 we estimate
20 about the same level of investment need as we did
21 in 2020.

22

The next column is reliability
23 projects. Those are increasing by \$33 million.

24

Storm hardening investment is
25 continued at a total similar to the 2020 level of

1

2 \$94 million.

3

4 And then moving over to the right,
5 Utility 2.0 projects. The capital portion of that
6 program has increased by \$21 million to reflect
7 some acceleration of \$17 million for SmartMeter
8 programs from 2022 into 2021.

8

9 The objective of the acceleration
10 is to complete 95 percent of the SmartMeter rollout
11 by September of 2021.

11

12 Next slide.

12

13 The budget includes \$323.5 million
14 in clean energy investments. The largest components
15 are:

15

16 \$98.8 million in renewable power;

16

17 and,

17

18 \$87.2 million for energy

18

19 efficiency in distributed energy programs.

19

20 Next slide.

20

21 So those are the highlights for
22 the budget dollars. Now what does that mean for
23 customers? This slide shows you the average
24 residential bill impact. The 2020 residential usage
25 for electricity was higher than anticipated. This
was due to weather but the other impact has been

1

2 from COVID-19 restrictions and customers working
3 from home and children attending school remotely.

4

As a result, the residential bills
5 have averaged around \$167 per month, compared to
6 \$155 per month based on the 2020 budget.

7

The average residential bill will
8 decrease slightly in 2021 to \$164 per month, or
9 about a two percent, assuming we have continued
10 elevated pandemic usage and then normal weather.

11

The \$3.79 reduction reflects an
12 increase in delivery charge, and that is offset by
13 the projected savings in power supply and then
14 other adjustments.

15

Now I'll turn the presentation
16 back over to Justin. He's our Vice President of
17 Public Policy and Regulatory Affairs.

18

MR. BELL: Great.

19

Thank you, Tamela.

20

So next slide, please.

21

We are pleased to offer a set of
22 tariff proposals that will introduce new
23 time-of-use rate options for customers, give
24 community distributed generation, or CDG hosts, a
25 net crediting option, allowing them to avoid

1

2 separate billing of their subscribing customers,
3 improve LIPA's ability to manage costs and
4 volatility for the benefit of customers and give
5 prospective tenants and landlords access to
6 information about the cost of electricity at a
7 rental property.

8

Next slide, please.

9

Time-of-use rate options can help
10 customers save money while also benefiting the
11 environment by preventing dirty peaking generation
12 and costly infrastructure upgrades.

13

By choosing one of the new
14 time-of-use rate options, shown here, the customer
15 can receive a lower rate at off-peak times, such as
16 overnight and a standard rate during most of the
17 daytime. In exchange, the customer agrees to a
18 higher rate during a pre-selected three or
19 four-hour peak.

20

These new rate options will
21 feature shorter peaks than our old time-of-use
22 rates, as well as a potential super off-peak period
23 during the night time.

24

The new options also include a two
25 period rate that will work well for electric

1

2 vehicle owners who are willing to charge their EV
3 at night but would prefer a flatter rate during the
4 daytime.

5

To help customers choose the best
6 rate for them, PSEG Long Island is also introducing
7 new tools that customers can use to compare options
8 and learn how they can can save on their bills.

9

We are expecting that the new
10 options, if approved by the board, will be
11 available to customers beginning in February of
12 2021.

13

So just to walk people through how
14 do we define the options, include four residential
15 options, one small business option and the peak
16 periods are shown here in red. The super off-peak
17 in green. Everything else is at a standard rate.
18 And then, finally, the ratio on the right-hand side
19 of the slide refers to in the summer time what is
20 the ratio of that period to the standard rate.

21

So with that, I will move on to
22 the next proposal because we want to leave plenty
23 of time for public comment.

24

Next, I'm going to talk about the
25 CDG net crediting option. So net crediting for

1

2 community distributed generation, or hosts of CDG
3 projects, is an option that allows developers of
4 these projects, such as community solar, to avoid
5 separate billing of those subscribing customers.

6

7 Instead, the CDG host designates
8 the savings rate, which is the percentage of the
9 value stack credit generated by the project.

10

11 They're applied as credits on the bill for a PSEG
12 Long Island customer who chooses to participate in
13 this program.

14

15 PSEG Long Island then sends the
16 remainder of the value stack credit to the CDG host
17 and that's their subscription fee, less a one
18 percent administrative fee is retained by the
19 utility to cover the cost of the billing.

20

21 So this new approach, again, is
22 optional. The CDG host can remain on the old
23 approach, which is shown above. The primary
24 difference with the old approach is that the CDG
25 host needs to separately bill the subscriber and
then collect payments from the subscriber.

26

27 So the new approach was designed
28 by the Department of Public Service in consultation
29 with stakeholders from all around the State and

1

2 ordered by the PSC, the Public Service Commissions
3 for the State's Investor Owned Utilities. And we
4 are now proposing to the LIPA Board that they adopt
5 the same approach here in Long Island.

6

We think the benefits include
7 lowering costs for community distributed generation
8 projects, which can then pass those savings on to
9 their subscribing customers.

10

So with that, I'll move on to the
11 next proposal.

12

We can go to the next slide,
13 please.

14

Great.

15

So LIPA is proposing changes to
16 two of our rate adjustment mechanisms for the
17 purpose of better managing costs and volatility.
18 The first one I'll discuss here is a change to the
19 revenue de-coupling mechanism.

20

What we propose to do is cap the
21 RDM, in any given year at five percent. Meaning
22 that the RDM rate, which is a percentage on the
23 customers' delivery charges could not exceed five
24 percent for any given class.

25

Note -- it's important to note

1

2 that this change would not involve changes in the
3 amount of revenues that the utility recovers from
4 each class, rather it's simply a timing change.
5 Because to the extent that any class exceeds the
6 five percent, the excess would be recovered from
7 the same class in the following period.

8 We believe this will be
9 particularly helpful to some of our customer
10 classes during this COVID period because it will
11 avoid potential RDMS that could be in excess of
12 five percent, particularly for commercial classes.

13 The next change that I would like
14 to discuss -- oh, sorry. The same slide, just the
15 bottom half of the slide -- of the previous slide,
16 15.

17 Thank you.

18 So we're also proposing changes to
19 what we call our delivery service adjustment or
20 DSA. And what the DSA is, for people who aren't
21 familiar, is reconciliation. It reconciles cost
22 components that are particularly outside of the
23 control of the utility and are subject to
24 volatility.

25 We think that the DSA benefits

1

2 customers by lowering LIPA's overall borrowing
3 costs and because LIPA is a public power utility,
4 the ultimate beneficiaries of the lower costs are
5 customers.

6 So currently today, the DSA
7 reconciles differences in debt service costs, as
8 well as storm costs. We're proposing to add three
9 other related categories -- costs that fall into
10 this category.

11 One, is non-storm emergency costs.
12 So emergencies other than storms. As I mentioned,
13 storms are already reconciled in the DSA.

14 The second is writeoffs of
15 uncollectible customer debts; and,

16 The third is pension and other
17 post employment benefits, such as health care.

18 So all of these proposals are in
19 the process of being reviewed by the Department of
20 Public Service and we will take their
21 recommendations, together with all the public
22 comments that we receive to the Trustees when we
23 propose this to the Trustees at their December
24 meeting.

25 There's one more, lest we forget,

1

2 Lisa, if you could next slide, please.

3

4 That this proposal is simply to
5 implement a new provision of the Public Service
6 Law, which requires utilities, all utilities,
7 electric and gas, to give prospective tenants and
8 landlords access to cost information, energy cost
9 information for rental properties.

9

10 So our proposing to do this that
11 the prospective tenant or landlords or other
12 authorized party, sends a request to PSEG Long
13 Island who would respond within ten days, at no
14 cost, and the cost to the utility would be minimal,
15 is projected to be minimal.

15

16 So with that, I believe we're
17 ready to move to the public comment portion. Yes,
18 we are.

18

19 So, Lisa, if you could just move
20 to -- yes, that slide.

20

21 And so, again, as discussed at the
22 beginning, the way this work is that we will be
23 calling speakers one at a time from the list of
24 people who signed up in advance. However, if you
25 have not already signed up, feel free to send us a
e-mail or a note in the chat box here and we will

1

2 add you.

3

And then as a reminder, when you are called, please do remember to unmute yourself.

5

Okay.

6

So turning to the sign-up sheet.

7

The first speaker that we have today is Adam Cohen from ninedotenergy.

9

Adam, if you're on, please just remember to unmute yourself.

11

MR. COHEN: Can I be heard by you, Justin?

13

MR. BELL: Yes.

14

MR. COHEN: Good.

15

Good afternoon.

16

Thanks for the opportunity to provide my comments on the proposed modifications to the LIPA tariff.

19

My name is Adam Cohen. I'm the Chief Technology Officer and a co-founder of a New York-based clean energy development company called ninedotenergy.

23

Ninedot is developing clean, distributed energy research projects on Long Island and New York City. We define technology as

25

1

2 including battery energy storage systems and solar
3 photovoltaics.

4

5 We develop community distributed
6 generation host sites, also called CDG host sites
7 and use the value of distributed energy resources
8 or VEDR values back in tariffs.

8

9 We then sell CDG subscriptions
10 that are guaranteed savings to utility customers.

10

11 I'd also like to mention that we
12 applaud LIPA's continuous efforts to improve the
13 VEDR value tariff and provide new ways for the
14 benefits and costs of distributed energy resources
15 or DERs, to be determined.

15

16 My comments today are with respect
17 to two of the proposed modifications to the LIPA
18 tariff and how they can better align with other
19 parts of the LIPA tariff and tariffs of New York's
20 investor owned utilities.

20

21 Number one, we're excited by the
22 launch of five new residential and small commercial
23 tenant use rates that allow the supply component of
24 customers' utility bills to vary by time of day,
25 day of week and time of year.

25

I personally studied both LIPAs

1

2 and earlier, LILCO's tariffs since the 1960s, that
3 include the power supply charge, the earlier fuel
4 and purchase power cost adjustment and before that
5 the fuel cost adjustment.

6 These rates have always been fixed
7 and unvarying throughout a month. With these new
8 proposed rates, Long Islanders will be able to pay
9 for electricity supply in a way that better matches
10 the cost of the electricity at different times of
11 the day.

12 The time differentiated power
13 supply chart will be cheaper at non-peak times and
14 more expensive at peak times, as they should be.

15 This is a major step forward and I
16 look forward to adopting these changes.

17 These changes also apply to other
18 time-of-use rates in the LIPA tariff. In
19 particular, the mandatory large demand metered
20 service with multiple rate period rate classes;
21 that's 284, 285M, 284M and M285 should also adopt
22 time differentiated power supply charges.

23 While time to (Zoom inaudible)
24 power supply charges -- supply prices that are used
25 by other utilities in New York, it would be a big

1

2 step forward for LIPA's customers with more than
3 145 kilowatts of demand.

4

5 For example, the off-peak rates
6 from 11:00 p.m. to 7:00 a.m. for rate 284 and from
7 midnight to 7:00 a.m. for rate 285, could be 60
8 percent of the non-timed differentiated power
9 supply charge. And other multipliers should be
used for the intermediate and peak periods.

10

11 Those change -- in particular make
12 energy storage a more compelling value proposition
13 for Long Island businesses who can charge batteries
14 at night and reduce their consumption during peak
times.

15

16 In fact, LIPA has already
17 committed to making such a change with an earlier
18 tariff modification in 2019. When the VEDR value
19 stack was expanded to include new generation
20 technologies, including stand-alone energy storage
21 on July 24th, 2019, LIPA stated in their order,
22 "The Department of Public Service recommends that
23 LIPA require customers with stand-alone energy
24 storage systems enroll in an eligible time-of-use
25 rate for imports and receive value stack crediting
for hourly exports as this would be more consistent

1

2 with the statewide approach and the principles of
3 the VEDR. The Authority staff agrees and has made
4 this change. To be further aligned with the
5 Commission orders, the Authority will also
6 implement hourly pricing for these customers as
7 soon as it has the capability to do so."

8

That's the end of the quote.

9

So in summary, ninedot strongly
10 supports that LIPA expand that kind of power supply
11 charge to other time-of-use rates in multiple rate
12 period rate codes.

13

And then my second comment is
14 related to the consolidated billing or remote
15 crediting program.

16

Ninedot supports LIPA's
17 implementation of consolidated billing for
18 community distributed generation satellite
19 customers. This change will give Long Island homes
20 and businesses a way to easily participate in local
21 clean energy projects. This is especially important
22 for low and moderate income households.

23

However, there is no one size fits
24 all approach to the CDG marketplace. And I have
25 three suggestions that will make this proposal

1

2 better for customers and for developers.

3

4 First, developers should be able
5 to set the savings rate for each customer
6 individually. This allows developers to vary their
7 offering.

8

9 For example, a larger saving rate
10 can be offered to residents in close proximity to a
11 solar farm. Or the savings rate could be lower for
12 large anchor subscribers who save money overall but
13 need a lower savings rate to do so, like a big box
14 store.

15

16 Second, more than one large
17 subscriber should be able to opt out of
18 consolidated billing. A community solar project,
19 for example, may have two or more anchor
20 subscribers.

21

22 Finally, LIPA should also adopt
23 the remote crediting model as its successor to the
24 remote net metering model that will be implemented
25 by other New York electric utilities. Remote
26 crediting allows up to ten large customers to
27 participate in a local clean energy project.

28

29 This option will give Long Island
30 businesses, schools and government buildings a new

1

2 way to support clean energy.

3

4 Thank you for the opportunity to
5 provide my comments on the LIPA tariff today.

6

7 Again, good afternoon.

8

9 Thank you.

10

11 MR. BELL: Adam, thank you very
12 much.

13

14 We really appreciate you taking
15 the time to come today and comment and we will take
16 your comments back and share them with all of our
17 staff and management and the board, as well as with
18 PSEG Long Island and the Department of Public
19 Service.

20

21 So I don't believe we have any
22 other speakers currently signed up. But let me
23 just see if there is anyone here on the call today
24 who has not yet signed up yet but is interested in
25 speaking. If so, you know, please sign up through
26 chat or since there's not too many people in the
27 room right now, you can probably just come up and
28 give a comment.

29

30 (No response.)

31

32 MR. BELL: Okay. So hearing none,
33 we will -- the way that we will proceed now is that

1

2 we will go on mute and we will hold and for the
3 rest of the hour to see if any additional
4 commentors come.

5

At that time, we will go back on
6 the record and take those comments.

7

But for now, I'm going to ask the
8 court reporter to go off the record and we will
9 adjourn until we get more commentors here.

10

Thanks everyone for your
11 attendance.

12

Feel free to stick around if you
13 would like to. Again, we will be here for the rest
14 of the hour.

15

Thanks so much.

16

(At 2:29 p.m., the hearing was
17 temporarily recessed.)

18

(At 3:00 p.m., the hearing
19 resumed.)

20

MR. BELL: Okay, folks. I'm just
21 going to give it another two minutes and then go
22 back on the record and close it out.

23

(Brief recess.)

24

MR. BELL: Okay.

25

Marc, are you ready to go back on

1

2 the record?

3

THE STENOGRAPHER: Yes, Justin.

4

MR. BELL: Great.

5

All right.

6

7 It is now 3:00 o'clock and we have
8 not received any more requests to comment at
9 today's session.

10

11 So as a reminder, people may
12 submit comments in writing, really any time up
13 until the board meeting. However, we prefer to
14 receive comments by December 1st to allow staff
15 time to summarize and prepare those materials and
16 briefing materials for the Board of Trustees.

17

18 Comments may be e-mailed to
19 tariffchanges@lipower.org.

20

21 There's another public comment
22 session tomorrow at 10:00 a.m. And the virtual
23 conference information is available on the
24 Authority's meeting website.

25

26 So this concludes today's public
27 comment session. Thanks, everyone for attending.

28

We are now adjourned.

29

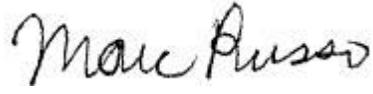
30 (At 3:01 p.m., the hearing was
31 concluded.)

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STATE OF NEW YORK)
SS.
COUNTY OF NEW YORK)

I, MARC RUSSO, a Shorthand
(Stenotype) Reporter and Notary Public within and
for the State of New York, do hereby certify that
the foregoing pages 1 through 27, taken at the time
and place aforesaid, is a true and correct
transcription of my shorthand notes.

IN WITNESS WHEREOF, I have
hereunto set my name this 1st day of December,
2020.



MARC RUSSO

Concordance

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LONG ISLAND POWER AUTHORITY

-----x

VIRTUAL ZOOM

TARIFF PUBLIC COMMENT SESSION

-----x

November 19, 2020

10:00 A.M.

B e f o r e :

JUSTIN BELL,

Director of Rates and Regulations

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A P P E A R A N C E S :

FROM LIPA

Justin Bell

Director of Rates and Regulations 3

Tamela Monroe

LIPA CFO 7

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2

P R O C E E D I N G S

3

MR. BELL: Hello, everyone.

4

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6

7

So the only name I don't recognize so far on the participant list is Lisa. And I don't think we have anyone signed up to comment today.

8

9

10

11

So Lisa, I was wondering if you could possibly go off mute and identify yourself and whether you want to comment today or are just hear to listen.

12

13

14

MS. BROUGHTON: Hi, Justin.

This is Lisa Broughton.

Can you hear me?

15

16

MR. BELL: Okay. Yes. Hi.

I was wondering if that was you.

17

18

19

MS. BROUGHTON: Sorry. I don't

know how to rename myself on the go to meetings

yet.

20

21

22

But I'm Lisa Broughton, Suffolk

County Energy Director. I am not here to comment.

I am here only to listen.

23

24

MR. BELL: Okay. Great.

25

Well, so we're going to give it a couple of more minutes. Let's wait until five after

1

2 to see if more people come. Because so far I think
3 you're the only one who hasn't seen this
4 presentation before on the call.

5

(Off the record.)

6

MR. BELL: Okay. Great. So
7 we're about to get started.

8

I just wanted to see -- I see one
9 person here on the list, Chuck Johnson. We don't
10 have you signed up to comment. So are you
11 interested in commenting today or are you just here
12 to listen?

13

MR. JOHNSON: I'm here to listen.

14

MR. BELL: Okay. Great.

15

(Off the record.)

16

MR. BELL: Good morning.

17

Welcome to today's public comment
18 session.

19

My name is Justin Bell and I'm
20 here today on behalf of LIPA and I'm joined by
21 Tamala Monroe, LIPA's CFO.

22

The purpose of this session is to
23 receive public comments on LIPA's proposed 2021
24 budget and a set of proposals to modify LIPA's
25 tariff for electric service.

1

2

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6

The proposed budget is available on the main landing page of LIPA's website and the tariff proposals are available on our proposed rule making page. They are incorporated into the record of this hearing.

7

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In a moment, I'll turn it over to Tamela for a brief presentation on the 2021 budget and then I will briefly summarize the tariff proposals.

11

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After the presentations, we will call the names of members of the public who have signed up to make comments. If you want to speak but haven't yet signed up, please send an e-mail to tariffchanges@lipower.org, indicating your name, your organization that you're speaking on behalf of, if any. And you may also use the chat feature of go to meetings and indicate your desire to speak.

20

21

22

When you're called to speak, please start by unmuting your phone or computer.

23

24

25

A full transcript of your comments today will be provided to LIPA's Board of Trustees for their consideration prior to the next board meeting. Your comments will also be provided to the

1

2 Department of Public Service, the LIPA staff and
3 PSEG Long Island for their review and
4 consideration.

5 Please note that today's session
6 is being recorded.

7 As the purpose of this hearing is
8 to receive your comments, we will not be responding
9 to comments or questions at today's hearing.
10 Rather, comments or questions may be sent in
11 writing to the same e-mail address,
12 tariffchanges@lipower.org and written comments on
13 the tariff proposal need to be received by December
14 1st. We do take comments after that date, up until
15 the board meeting but by providing your comments by
16 December 1st that gives us time to summarize them
17 and allow staff to incorporate them into the
18 briefing materials for the Board of Trustees before
19 the meeting.

20 So now I'll turn it over to Tamela
21 to provide a brief summary of the proposed budget.

22 Tamela, it's all yours.

23 MS. MONROE: Thank you, Justin.

24 So good morning, everyone and
25 thank you for joining us.

1

2

The budget for LIPA is based on our strategy and our strategy is clean, lean and customer first.

5

6

The work we do and the planning for that work is all based on that strategy. And we also developed the budget to accomplish that work.

9

10

So I'd like to take a minute to -- I'd like to take a minute to explain the environment in which we started to develop the 2021 budget.

13

14

15

16

17

As soon as the impact of the pandemic became apparent, we looked into belt tightening measures, not only for 2020 but across the next three years as we understood the impact that could be prolonged for our customers.

18

19

20

I also want to mention that these measures do not adversely impact reliability or our ability to deliver service to our customers.

21

22

23

Listed on this slide are the details of the operating and capital reductions that we have implemented this last year.

24

Next slide, please.

25

One of our strategies is to

1

2 operate lean. This slide provides a list of cost
3 savings from lean efforts that total \$718 million
4 in 2021. That equates to approximately \$32 per
5 month savings for an average residential customer.

6

Next slide, please.

7

8 The 2021 budget has two
9 components; the first piece is an operating budget,
10 which is \$3.76 billion. \$3.66 billion of that will
11 be collected from our customers through rates and
12 tariffs.

12

13 And \$58.7 million will be received
14 from grants and interest income.

14

15 On the left side of this slide in
16 the middle, you can see the cost categories that
17 comprise the budget. On the right side of the
18 slide is the capital budget and that request is
19 \$766 million. The capital improvements in the
20 system are \$671 million with an additional \$94
21 million in storm hardening in 2021.

21

Next slide.

22

23 Now let's look at the details of
24 the operating budget. This slide compares the 2020
25 budget with the 2021 proposed budget.

25

The first thing to note is the

1

2 total requested budget is lower than the 2020
3 budget by \$4.8 million.

4

5 You start on the left side of the
6 slide -- that's the 2020 approved budget of \$3.666
7 billion. And on the right side is the 2021 proposed
8 operating budget to be collected from customers and
9 that is \$3.662 billion.

9

10 In the middle are the increases
11 and decreases by cost category. The largest
12 increase is in the debt payments and coverage for
13 both LIPA and the UDSA debt, which is \$23 million.

13

14 The largest decrease is in power
15 supply costs. And that's projected to decrease by
16 \$69 million, or almost four percent.

16

17 Next slide, please.

17

18 So turning to the capital portion
19 of the budget, the proposed capital budget, as I
20 said, was \$766 million. That's \$36 million less
21 than 2020. The largest changes in the regulatory
22 projects with the completion of the Western Nassau
23 Transmission Project in 2021 and the level of
24 regulatory driven capital projects is significantly
25 reduced by about \$95 million.

25

Local projects are always of an

1

2 interest in the community. In 2021, we estimate
3 about the same level of investment needed as in
4 2020.

5 The reliability projects are being
6 increased by \$33 million.

7 Storm hardening efforts continued
8 at a total, which is similar to the 2020 level,
9 which is \$94 million.

10 Moving over to the Utility 2.0.
11 This is the capital portion of that program. This
12 reflects the acceleration of 17 million of
13 SmartMeter programs from 2022 to 2021. So the
14 total project for capital investment would be \$21
15 million in this budget.

16 The objective of the acceleration
17 is to complete 95 percent of the SmartMeter rollout
18 by September of 2021.

19 Next slide.

20 The budget also includes \$323.5
21 million in clean energy investments. The largest
22 components are:

23 \$98.8 million in renewable power;
24 and,

25 \$87.2 million in energy efficiency

1

2 in distributed programs.

3

Next slide.

4

5 So those are the highlights in the
6 budget dollars. So what does that mean to the
7 customers? This slide shows the average
8 residential bill impact. In 2020 residential usage
9 for electricity was higher than anticipated. This
10 was due to -- partly to the weather but mostly from
11 the impact of COVID-19 restrictions and our
12 customers working from home and children attending
13 school remotely.

13

14 As a result, residential bills
15 have averaged around \$167 per month, compared to
16 \$155 per month in the 2020 budget, which was normal
17 usage patterns.

17

18 An average residential bill has
19 decreased slightly in 2021 to \$164 per month, or
20 about a two percent reduction. This is assuming we
21 have extended pandemic usage and normal weather.

21

22 The \$3.79 reduction, plus the
23 increases in delivery charges, it is offset by the
24 projected savings in power supply and other
25 adjustments.

25

Now I'll turn the presentation

1

2 back over to Justin, who is our Vice President of
3 Public Policy and Regulatory Affairs.

4

MR. BELL: Great.

5

Thank you, Tamela.

6

Next slide, please.

7

8 So we're pleased today to offer a
9 set of tariff proposals that will introduce new
10 time-of-use rate options for customers, give
11 community distributed generation, or CDG hosts, a
12 net crediting option, allowing them to avoid
13 separate billing of their subscribing customers,
14 improve LIPA's ability to manage costs and
15 volatility for the benefit of customers, and give
16 prospective tenants and landlords access to
17 information about the cost of electricity at a
18 rental property.

18

Next slide, please.

19

20 So time-of-use rate options can
21 help customers save money while also benefiting the
22 environment by preventing dirty peaking generation
23 and costly infrastructure upgrades.

23

24 By choosing one of the new
25 time-of-use rate options, shown here on this slide,
the customer can receive a lower rate at off-peak

1
2 times, such as overnight and a standard rate during
3 most of the daytime. In exchange, a customer
4 agrees to a higher rate during a pre-selected three
5 or four-hour peak.

6 These new rate options feature
7 shorter peaks than are old time-of-use rates, as
8 well as a super off-peak period during the night
9 time for most of these options.

10 The new options also include a two
11 period rate that will work well for electric
12 vehicle owners who are willing to charge their EV
13 at night but prefer a flatter rate during the
14 daytime.

15 To help customers choose the best
16 rate for them, PSEG Long Island is also introducing
17 new tools that customers can use to compare options
18 and learn how customers can save money.

19 And I'm not going to go in detail
20 through this slide, but I will just point out that
21 the main features here where you can see the times
22 that apply to the different peak periods and the
23 different rate options. And then on the right-hand
24 column, you can see the ratio that is -- what is
25 the ratio of the rate during that period to the

1

2 standard rate.

3

4 So it's helpful to get a sense of
5 how much the customer would be paying on and off
6 peak and during the overnight time if they chose
7 one of these options.

8

9 So together with this, we're also
10 proposing to phase out several of our older
11 time-of-use rates and those are proposed to be
12 closed to new customers and as of 2025 the existing
13 customers would be able to move to a standard rate
14 or to a new -- one of the new time-of-use rates.

15

16 We also have had the proposal
17 reviewed by the Department of Public Service who
18 provided feedback, which has been incorporated into
19 the proposal. And so we also welcome any public
20 comments.

21

22 We're going to wait until the end
23 of the presentation and then we'll take any public
24 comments on both the budget presentations that
25 Tamela just gave us, as well as these tariff
26 proposals.

27

28 So let's go to the next slide,
29 please.

30

31 Okay. So net crediting for

1
2 community distributed generation is an option that
3 allows developers of CDG projects, which is
4 community solar, to avoid having to separately bill
5 their subscribing customers. Instead, the CDG host
6 designates the savings rate, which is the
7 percentage of the value to that credit generated by
8 the project that is applied as credit on the bill
9 for a PSEG Long Island customer who is
10 participating as a satellite -- what's called a
11 satellite subscriber for the CDG project.

12 And PSEG Long Island will then
13 send the remainder of the value stack credits to
14 the CDG host. This is known as the host
15 subscription fee and the utility retains a one
16 percent administrative fee.

17 This approach is proposed to be
18 identical to the approach that was ordered by the
19 Public Service Commission of New York or the State
20 investor owned utilities, and it was the result of
21 a comprehensive stakeholder process that had a lot
22 of engaged stakeholders submitting comments,
23 participating in working groups, technical
24 conferences, et cetera. So we think that they are
25 a very good compromise solution.

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One of the benefits of the new approach is that it does save on overall costs of community solar because the CDG hosts no longer has to issue separate bills and collections to the subscribers. That's all now going to be utilizing the utility that's been billing the collection systems.

They -- you can see on the slide how it compares to the old approach. The diagram, I think we've covered all of this, but I do think that it's going to be a good option.

Again, we'll continue to monitor the activities of the PFC so that if there are any other changes or related tariffs that they order to be put in place, we'll consider those and bring them to LIPA's board as appropriate.

Next slide, please.

So LIPA is also proposing changes to two rate adjustment mechanisms for the purpose of managing costs and volatility.

First, we propose to change the revenue de-coupling mechanism to cap the RDM, at five percent for each class.

So what does the mean? The

1

2 revenue de-coupling mechanism is a reconciliation
3 that allows the Authority to either recover or
4 return to customers the difference between the
5 revenues that we were approved to recover during
6 the period, which is a year and the revenues that
7 we actually recover due to the differences in
8 sales.

9 So in each class the revenues that
10 we recovered could actually be more or less than we
11 forecast when we're putting together the budget.
12 And so what happens if this change is approved, is
13 that if a -- if the revenues in any particular
14 class underran budget so much so that the following
15 year's RDM rate would exceed five percent, we would
16 propose to cap that at five percent in order to
17 ensure that -- particularly now during economically
18 challenging times, you know, we don't have
19 particular customer classes who are burdened by an
20 expensive RDM.

21 Instead, any excess over five
22 percent would simply be carried over to the next
23 period and recovered from the same class. So
24 there's no change in the sort of cost subsidy
25 amongst classes here because the revenues --

1

2 assuming we're covered from the same class and it's
3 just that -- they would be recovered later.

4

And this here in particular next
5 year rather, we think that this is going to be
6 important because some of the -- due to COVID and
7 the related shutdowns, some of the commercial
8 classes, are projected to have RDMs that would be
9 in excess of five percent.

10

So turning now to the second half
11 of the slide, changes to our delivery service
12 adjustment. So the delivery service adjustment is
13 (Zoom inaudible) mechanism. It reconciles cost
14 components, typically from what was budgeted to
15 what was actually experienced or accrued.

16

And the cost components that
17 are reconciled in the DSA are generally components
18 that are subject to volatility. And that's beyond
19 the utility's control and we think that the DSA
20 benefits customers by lowering LIPA's overall
21 borrowing costs and since LIPA's a publicly owned
22 non-profit utility, customers, of course, are the
23 ultimate beneficiary of lower costs. There's no
24 shareholder there to absorb any profit or take any
25 of those savings.

1

2

The proposal today would add three components to the DSA and that is:

3

4

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8

Emergencies other than storms, what we refer to as non-storm emergencies, to the extent that PSEG Long Island requested a budget amendment for those and that was approved by the Trustees;

9

10

11

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14

It would also include writeoffs, uncollectible customer debt. So to the extent that those -- the amounts that are accrued and approved by our auditor are different from what we budgeted at the beginning of the year, we would propose that that be reconciled; and,

15

16

17

18

Then finally pension and other post employment benefits, such as health care, to the extent that those amounts change during the year, we would propose to reconcile those as well.

19

20

So this would add to the existing categories, which are storms and debt service.

21

22

23

24

25

And so these two proposals are being reviewed by the Department of Public Service and they will provide better advice to the Board of Trustees before the board meeting, which is in December.

1

2

Next slide, please.

3

Finally, we have a proposal to implement a new provision of the Public Service Law and that provision provides that prospective tenants or landlords may request from any electric or gas utility cost information about a rental property. And so the purpose here is really to give prospective tenants or landlords or other authorized persons a sense of the electric costs for owning or renting a property.

12

And we would propose to comply fully with the new provision and so the information would be provided upon ten days -- within ten days of a request and at no cost.

16

So that proposal's pretty straightforward and I believe that is the last one.

18

So now we will proceed to the public comment period.

20

We currently did not receive any signups for today's session. However, I see that there are a few folks here on the Go To Meeting from the public. So if any of you have decided to comment, please feel free to send us a note in the chat or send us an e-mail at this address, to

25

1

2 tariffchanges@lipower.org.

3

4 And if we do not have any
5 commentors at this time, then we are -- we will go
6 on hold and we will go off the record for the
7 remainder of the hour while we wait to see if there
8 are other people who will be joining us to speak
9 later.

9

(No response.)

10

11 MR. BELL: Okay. So hearing none,
12 and seeing none in the e-mail in box, let's go
13 ahead and go off the record and I'm going to go off
14 camera.

14

15 Feel free to stick around, folks
16 to see if we get any more commentors. We will be
17 here for the rest of the hour. And at that time we
18 will adjourn the session.

18

Thank you.

19

(Brief recess.)

20

MR. BELL: Hi, everyone.

21

22 It is now just about 11:00 and we
23 do not have any more speakers.

23

24 So let's go back on the record
25 very quickly and close it up.

25

Marc, are you ready?

1

2

THE STENOGRAPHER: Yes, I'm ready.

3

MR. BELL: Okay. Great.

4

All right.

5

Good morning, again.

6

7

It is now 11:00 and we have not had any additional public commentators.

8

9

10

We thank everyone for their participation and note that written comments may still be submitted to tariffchanges@lipower.org.

11

12

13

And we invite everyone to view the board meeting in December, on December 17th, I believe.

14

So that's it.

15

And we are now adjourned.

16

Thanks again.

17

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(At 11:01 p.m., the proceedings were concluded.)

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STATE OF NEW YORK)

SS.

COUNTY OF NEW YORK)

I, MARC RUSSO, a Shorthand
(Stenotype) Reporter and Notary Public within and
for the State of New York, do hereby certify that
the foregoing pages 1 through 23, taken at the time
and place aforesaid, is a true and correct
transcription of my shorthand notes.

IN WITNESS WHEREOF, I have
hereunto set my name this 1st day of December,
2020.



MARC RUSSO

Concordance

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Exhibit E - Compendium of Written Public Comments Received

From: [Steve Ripp](#)
To: [Tariff Changes](#)
Subject: Comments Re: Proposed CDG Net Crediting
Date: Tuesday, November 3, 2020 9:07:58 PM

These comments pertain to LIPA's proposed tariff changes regarding the institution of community distributed generation (CDG) net crediting. FourGen LLC is developing CDG projects in LIPA's service territory and is highly supportive of net crediting of CDG satellite customers because of its many attendant benefits. FourGen would like LIPA to make net crediting available to all CDG projects, not only those compensated via the Value Stack method as the tariff changes propose.

With net crediting, satellite customers enjoy the convenience of a single bill from PSEG Long Island rather than paying both the utility and the CDG host. The savings realized from participating in CDG will be more transparent to the customer and easier to understand. Net crediting also increases the likelihood that a potential customer will participate in CDG because of greater trust in the utility's billing process than in that of a new, unfamiliar entity. For each CDG host, net billing avoids the investment in information technology and overhead associated with the monthly billing and collection from potentially thousands of accounts. These activities are not core competencies of energy project developers. Net billing is a more efficient and less expensive approach for CDG and the simplicity of receiving payments from the utility facilitates project financing for CDG hosts. With reduced capital requirements and ongoing administrative costs, more projects should be economic, offering greater savings to satellite customers.

With all of these benefits, what is the justification for restricting net crediting only to CDG projects that are compensated under the Value Stack method? CDG projects that qualified for other forms of compensation such as volumetric net metering should also be eligible. It is not a matter of complexity because volumetric credits are easier to compute than VDER credits. Nor is it a matter of cost because there are no anticipated financial impacts for this proposal, provided the administrative fee withheld from the CDG host payments compensates LIPA for the cost to administer this program.

I urge you to extend eligibility for net crediting to all CDG projects. It would seem arbitrary and unfair to non-Value Stack CDG projects not to do so.

Thank you for the opportunity to comment and for your consideration.

Sincerely,
Steve Ripp
President, FourGen LLC

LIPA IT WARNING: This email came from an external source. THINK before you open attachments or click on links and NEVER provide IDs or passwords.



22 Edgemont Road
Katonah, New York 10536
(914) 282-7000

December 1, 2020

Ralph Suozzi, Chairman and
LIPA Board of Trustees
333 Earle Ovington Blvd.
Uniondale, NY 11553

Hon. Michelle L. Phillips
NYS Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223

Re: Community Distributed Generation ("CDG") net crediting tariff proposal, and:

Longer term decisions related to a viable electricity choice program on Long Island

With collaborative contribution from the Town of Southampton on matters related to CDG, the following is submitted to the LIPA Board of Trustees and the Public Service Commission (PSC) concerning LIPA's proposal to modify its CDG "Net Credit" Tariff and concerning tariff and strategic decisions yet to come but in consideration over the near-term

Dear Chairman Suozzi,

Community Distributed Generation.

We congratulate LIPA on what has clearly been a successful internal technology upgrade—the Authority could not have issued your Community Distributed Generation Net Crediting tariff proposal, without effectively upgrading your billing system.

This success holds out the opportunity to build a constructive process between LIPA and the local clean energy communities. We spotlight a couple of issues that may or may not rise to board-level, in order to offer a clear path to a smooth working relationship with the "grass roots" and in order to offer a heads up with respect to prospective fiduciary impact on the Authority:

1. The Town of Southampton notes that contracts that the authority signs with renewable energy developers are best structured with fair indemnification terms. Authority exposure could be limited to LIPA's negligence. Ideally, each of the developer and the Authority would mutually protect the other with legal support, should claims arise from acts or omissions of the other. Such fairness would set an example for the rest of the state with quite limited risk for the Authority.
2. The Town of Southampton notes that data agreements that LIPA writes for CCAs that receive data must be reflective of the CCA authority. CCAs are explicitly exempted for specific

restrictions outlined in the Uniform Business Practices issued by the PSC.¹ We see no board or fiscal impact from such a practice, whatsoever. In fact, drafting these data sharing agreements this way would simply indicate competence—your contracts department drafts for resilience and would clearly be in sync with regulatory affairs.

Responsiveness to the December 12th, 2019 Public Service Commission Order (Case # 19-M-0463):

“Remote net metering” may or may not comprise a substantial portion of Community Distributed Generation, going forward. In either case, in the event that LIPA completes further billing upgrades that will allow the Authority to also support net credit billing for these “Tranche Zero” facilities, legacy developers will, in our estimation, offer island residents a stream of bill savings in excess of \$2.5 million per year, for the next twenty years, beginning in 2021.

The Public Service Commission has, in its Order (Page 15), explicitly required regulated utilities to include these facilities in their bill system upgrades. We certainly understand the choice on the part of regulated utilities to first roll out billing system upgrades for “Value Stack” compensated CDG, then to address these Tranche Zero projects with further system enhancements. Now that Value Stack CDG upgrades have evidently been completed, however, apart from the clear message from regulators, it is the right thing for the Authority to do to complete such further upgrades in 2021, as soon as is viably possible.

CCA and Competitive Electricity Supply Options

We see progress on LIPA’s part, with respect to offering a viably competitive electricity market on Long Island. However, we see repeated patterns that could hinder that progress as well.

2021 holds the opportunity for LIPA to decide on a new strategic direction. The opportunity is there, without compromising the Authority’s fiscal stability: if 9,000 MWs of offshore wind are to be constructed in the next decade and LIPA were to upgrade its transmission and distribution systems, “wheeling revenues” will provide a powerful foundation for such fiscal stability. Because Zone I and J consumers will face increasing supply constraints, system upgrades will not necessarily cost LIPA ratepayers an exorbitant amount, annually.

Pro-actively reforming the LIPA Choice Program, to spark vibrant competition, would allow the Authority better control over that transition—it will fit in with a sensible and justifiable long-term vision.

Burdening ratepayers with continuing costs for legacy contracts, however, is not the best route for the Authority, in our view. Such an approach will inspire community resistance and expanded control from state government. To the degree possible, the Authority should simply no longer enter into long-term power or capacity supply agreements. We do not believe it necessary for LIPA default customers to

1

[https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/\\$FILE/September%202020%20UBP%20CLEAN.pdf](https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/$FILE/September%202020%20UBP%20CLEAN.pdf)

underpin offshore wind development. The market will, on its own and with only a modicum of state policy support for renewable resources, inspire the development of all offshore wind power outlined in the state plan (further detailed, below).

We are therefore hopeful that these considerations will guide your approach to reforming the Choice Program as we expect you will face several decision points with respect to the program, over the next twelve months.

Where do we see progress and pitfalls?

Progress. Based on requests for comment by LIPA staff in public and private, it appears that LIPA stands prepared to eliminate the power supply charge and the bill credit adjustment, from the Long Island Choice program. This is a positive change because it theoretically will allow competitive ESCOs to hedge supply risk with this change. The ability to reliably hedge supply costs will allow ESCOs to offer a fixed price to consumers. This provides real prospective consumer value.

We do not see this specific tariff change on the agenda for the December 16, 2020 Board meeting and we do not see any related change posted for future consideration. We would urge such a modification to the Choice Program to be prepared and posted as soon as possible, for comment in advance of LIPA's next board meeting.

Progress. We also laud the Authority for committing to provide a unified electricity bill for competitive suppliers under the choice program, by the close of 2021. This will eliminate a nagging concern of marketers and CCAs. Explaining to residents why they are now getting two bills, when they got only one before, is a challenge that holds the potential to create chaotic confusion. While this change is most salient when a viable Long Island Choice Program is introduced, we would value an update on expected completion of this unified bill offering such that it is clear that such a billing option will be available in a timely manner, in advance of the introduction of CCAs in the region. Clearly, this feature will not be widely utilized until necessary tariff modifications to the Choice are implemented. It is important, however, that the system upgrades are complete by the time these tariff modifications go into effect.

Progress. Based on requests for comment by LIPA staff in public and private, LIPA is intending, it seems, to allow competitive suppliers to reduce their costs to LIPA, if they want to self-supply long Island capacity. Sensibly priced and administered, this is a good thing. Ideally, suppliers will want to procure their on-island capacity independent from LIPA. This could allow, for instance, a supplier to enter into a power purchase agreement with a drawing board renewable power plant. Such plants will need power purchase agreements to satisfy financiers that the prospective investment is subscribed with a buyer. The change also holds the potential to also enable competitive suppliers to offer consumers dollars, in exchange for their commitment to reduce consumption on call. Suppliers could use this commitment to meet their "on-island capacity" buying requirements.

We do not see this specific tariff change on the agenda for the December 16, 2020 Board meeting and we do not see any related change posted for future consideration. We would urge such a modification to be prepared and posted as soon as possible, for comment in advance of LIPA's next board meeting.

Pitfall. One detail of LIPA's capacity market proposal could atrophy any competitive market. .

From discussions with staff, it appears that LIPA is considering reserving ~3.5 cents per kWh for previous contracts that the utility has entered into, that stretch through to 2027. Residents would pay this charge, whether they are buying as default energy customers or they are participating in competitive energy markets. That adds up to \$280 unavoidable cost for every Long Island customer.

This is precisely the approach that we outlined above as unwise, in our view. It will create continued push and pull between consumer groups, legislators, executives, environmental advocates, central New York government and the Authority. It will also diminish any chance that the Authority will find a friendly reception when the board does seek to implement enhancements to infrastructure and any ongoing revenue model to support such enhancements.

It is also unprecedented, beyond Long Island. Nowhere else in the state is a utility allowed to keep nearly this many dollars from customers who exit for competitive markets. Moreover, this kind of protection frankly encourages sloppy purchasing decisions.

Also, a market in which ownership of power plants overlaps with ownership of the buyer of power plants' product, is a recipe for impropriety. Even proper contracts that emerge from such contract negotiation will appear improper to any unbiased observer.

LIPA observes that there is precedent for such a charge. Con Edison retains half a penny per kWh for customers who buy competitively. In New York City this amounts to about \$30 per year per customer v the \$280 that LIPA is considering here.

A viable competitive market could withstand a charge similar to Con Edison's for well-intentioned buying decisions (reliability?), right or wrong, that were made years ago. However, good market design would reflect that no charge will mean no subsidy either way—a market that protects against inefficient buying decisions will not function optimally, on behalf of either consumers or on behalf of a reliability metric.

As it is in consideration, a competitive buyer would be granted a credit of less than two cents per kWh. For these dollars, the supplier would need to buy on island capacity for that consumer for roughly 150 per kW year, in order to hold costs to under two cents and to therefore serve the competitive customer on a level with LIPA default customers.

We noted above that the ESCO could get consumers to reduce their consumption during capacity hours, and satisfy their capacity buying requirements with that reduction.

However, to match the LIPA credit and therefore hold consumers harmless, an ESCO would need to sign up more than 3X as many customers as the ESCO serves. These consumers would need to reliably shed perhaps 1/3 of their consumption on call, thus saving the ESCO roughly \$50 for each customer they sign. Out of that \$50, the ESCO would need to build its system and marketing/sales apparatus, find and sign consumers who have already installed smart thermostats (or install such units), control the thermostats, and share something with customers they find willing to reduce consumption on call.

With the proffered LIPA credit proposal, such a program would simply not be viable.

As earlier outlined, couldn't an ESCO (instead of paying consumers for their willingness to shed consumption) fund the development of new power plants, by contracting with them for a power purchase agreement for on-island capacity?

The New York Independent System Operator calculates the cost of new entry (what a power plant would need in capacity compensation alone, to gain the security to build) at close to \$200 per kW. With this math, an ESCO would need to charge its typical residential customer roughly \$600 each year, to serve them on-island capacity, \$450 more than what LIPA is crediting that same customer.

The credit that will require ESCOs to buy additional supply on behalf of their customers, combined with an unavoidable 3.5 cent charge, will cost consumers more than they currently pay. This intended solution will leave Long Island residents precisely where they are today—their choice is not a viable choice.

We would urge that any modification to LIPA's on island capacity charge that retains any required consumer payment for legacy capacity agreements, be prepared and posted as soon as possible, for comment in advance of LIPA's next board meeting. We do not feel it wise for default consumers or for competitive consumers to pay for legacy contracts—we will support the Authority in seeking and gaining support for alternative solutions.

Pitfall. Similarly, LIPA now proposes to guarantee prices for to be constructed offshore wind facilities. Will these prove to be the new charges, placed unavoidably upon every consumer on Long Island? Such treatment would tie consumers to an unavoidable exit charge to LIPA, through 2045. Such a construct would repeat the error we allowed when the Authority entered into contracts through 2027. Is this the legacy that the LIPA board would like to leave Long Island consumers?

At a minimum, consumers who choose competition must not be stuck with energy or capacity prices that LIPA negotiates on their behalf, going forward.

CCA Administrators on behalf of the municipalities they serve, can negotiate their own deals with offshore wind facilities and with other renewable generation facilities. When a CCA enters into a longer-term contract, consumers retain the free right to exit at any time and the contract is preceded by a transparent consumer education program that reaches every household in town. This free exit feature is

not in place with current LIPA longer-term capacity agreements (as outlined above) and we are concerned that these new contracts will be similarly backed by all Long Island ratepayers.

A vibrant, competitive market, works quite well to ensure the development of renewable power, large and small, centralized and distributed. It works, as well, to ensure stable pricing, while offering consumers the opportunity to take advantage of low-price spot market windows. Current regulatory practice and current market service firms and procedures are quite protective of consumers' interests.

LIPA can and will thrive in such a market. We look forward to continuing to work with you to ensure that we get to that future, together and over a near-term horizon.

Best Regards,

Mike Gordon
Chief Executive Officer
Joule Assets, Inc.

E-mail: mgordon@jouleassets.com

Cellular telephone: (914) 282-7000

November 18, 2020
Adam Cohen
NineDot Energy
adam@nine.energy

COMMENTS ON PROPOSED LIPA TARIFF CHANGES

Thank you for the opportunity to provide my comments on the proposed modifications to the LIPA tariff.

My name is Adam Cohen. I am the chief technology officer and a co-founder of a New York-based clean energy development company called NineDot Energy. NineDot is developing clean distributed energy resource projects on Long Island and New York City. We deploy technologies including battery energy storage systems and solar photovoltaics. We develop community distributed generation, or CDG, host sites and use the Value of Distributed Energy Resources, or VDER, Value Stack. We then sell CDG subscriptions at a guaranteed saving to utility customers.

First, I'd like to mention that we applaud LIPA's continuous efforts to improve the VDER Value Stack Tariff and to provide new ways for the benefits and costs of DERs to be determined.

My comments today are with respect to two of the proposed modifications to the LIPA tariff and how they can better align with other parts of the LIPA tariff and the tariffs of New York's investor-owned utilities.

Comment 1

We are excited by the launch of five new residential and small commercial time of use rates that allow the supply component of customers' utility bills to vary by hour of day, day of week, and time of year. I have personally studied LIPA's and LILCO's tariffs since 1960 including the Power Supply Charge, the earlier Fuel and Purchased Power Cost Adjustment, and the Fuel Cost Adjustment before that. The rates have always been fixed and unvarying over a month. With these new proposed rates, Long Islanders will be able to pay for electricity supply in a way that matches the costs of electricity at different times of day. The time-differentiated Power Supply Charge will be cheaper at non-peak times and more expensive at peak times, as they should be. This is a major step in making power prices fairer. I fully support adopting these changes.

However, this change should also apply to other time-of-use rates. In particular, the Mandatory Large Demand Metered Service with Multiple Rate Periods rate classes 284, 285, M284, and M285 should also adopt time-differentiated Power Supply Charges.

While the time-differentiated Power Supply Charge is not as granular as mandatory hourly supply pricing used by other utilities in New York, it would be a big step for LIPA's customers with more than 145 kW of demand. The Off-Peak rates (from 11pm to 7am for Rate 284 and midnight to 7am for Rate 285) should be 60% of the non-time-differentiated Power Supply Charge and other multiples should be used for Intermediate and Peak Periods. This change will make energy storage a more compelling value proposition for Long Island businesses who can charge batteries at night and reduce their consumption during peak times.

In fact, LIPA already committed to such a change in 2019. When the VDER Value Stack was expanded to include new generation technologies including standalone energy storage on July 24, 2019, LIPA stated in their Order:

The [Department of Public Service] recommend[s]... that the [LIPA] require customers [with standalone energy storage systems] ... enroll in an eligible time-of-use rate for imports and receive Value Stack crediting for hourly exports, as this would be more consistent with the statewide approach and the principles of VDER. The Authority staff agrees and has made this change. **To be fully aligned with the Commission orders, the Authority will also implement hourly pricing for these customers as soon as it has the billing capability to do so.**

In summary, NineDot strongly suggests that LIPA expand their time-differentiated Power Supply Charge to its other time-of-use and multiple rate period rate codes.

Comment 2

NineDot supports LIPA's implementation of consolidated billing for community distributed generation satellite customers. This change will give Long Island homes and businesses to a way to easily participate in local, clean energy projects. This is especially important for low- and moderate-income households.

There is no one-size-fits-all approach to the CDG marketplace, and I have three suggestions that will make this proposal better for customers and for developers.

First, developers should be able to set the Savings Rate for each customer individually. This allows developers to vary their offering. For example, larger Savings Rates can be offered to residents in close proximity to a solar farm. Or the Savings Rates can be lower for large anchor subscribers who save more money overall, like a big box store.

Second, more than one large subscriber should be able to opt out of consolidated billing. A community solar project may have two or more anchor subscribers.

Finally, LIPA should also adopt the Remote Crediting model as a successor to the Remote Net Metering model that will be implemented by other New York electric utilities. Remote Crediting allows up to ten large customers to participate in a local clean energy project. This option will give Long Island businesses, schools, and government buildings a new way to support clean energy.

Via Electronic Mail

December 2, 2020

Mr. Justin Bell
VP, Public Policy and Regulatory Affairs
Long Island Power Authority
333 Earle Ovington Blvd
Uniondale, NY 11553
Email: tariffchanges@lipower.org

Re: Proposal Concerning Modifications to LIPA's Tariff for Electric Service

Dear Mr. Bell,

Below, please find comments submitted by PowerMarket in response to the Proposal Concerning Modifications to LIPA's Tariff for Electric Service and matters related PSEG Long Island's billing and crediting for Grandfathered and Phase One NEM CDG projects.

Respectfully submitted,



Jason Kaplan
Chief Operating Officer
PowerMarket
jason.kaplan@powermarket.io

PowerMarket requests that LIPA require PSEG Long Island to provide CDG Hosts and CDG Satellites the monetary value of the volumetric CDG credits applied to each CDG Satellite's bill each month, as applicable to Grandfathered and Phase One NEM CDG projects. All other investor-owned utilities ("IOUs") in New York share this information with CDG Hosts and CDG Satellites, and request that PSEG LI do the same. To be clear, this issue is unique to NEM CDG projects and would not be an issue for Value Stack CDG projects.

Presently, PSEG LI customers participating in NEM CDG projects neither see the kilowatt-hour ("kWh") credits offsetting their utility bill nor the nominal monetary value of the volumetric credits applied to these bills. PSEG LI treats CDG Satellites, for billing purposes, as if they were a net metering customer with behind-the-meter DG. When the Satellite looks at their PSEG LI bill, they will only see the net kWh (if any) in the Supply portion of their bill. They will not see their total kWh electricity used during that bill period and then the amount of kWh applicable to their CDG participation reducing the total kWh electricity used. The only visibility that a CDG Satellite may have on their PSEG LI bill will be if there had been any banked kWh credits accrued in prior months that were then applied to the current bill. Therefore, the PSEG LI utility bill, in its current form, does not tell the CDG Satellite how many kWh were applied to their account nor what the monetary value of those kWh credits applied.

Further, while CDG Hosts may be provided the total kWh applied to the Satellite's bill in a given month, the CDG Host Statements in their current form do not provide the CDG Host with the monetary value of those kWh credits applied. This lack of transparency in data to both the CDG Satellite and CDG Host make administering NEM CDG projects in PSEG LI untenable, if not impossible at scale.

The reason this visibility to both the kWh credits as well as the monetary value matters is that the prevailing CDG offering to Satellites is a guaranteed 10% discount to the value of bill credits each month. This value proposition has become the predominant offering because of its simplicity and ability to offer guaranteed savings to subscribers with no risk, thereby allowing scalability in acquiring subscribers. The predominance of this value proposition is evidenced by the fact that the Net Crediting program is built around the notion of a "CDG Savings Rate", with a minimum of 5%. CDG Hosts have offered this guaranteed savings product to Satellites both for NEM and Value Stack CDG projects because the IOUs have provided CDG Hosts and CDG Satellites the value of each month's credits so that the CDG Host can properly bill the customer for that value and the CDG Satellite can reconcile and realize this savings by viewing their utility bill. Attached please find sample Satellite bills from the IOUs showing the representation of the kWh credits applied as well as the monetary value associated with those kWh credits. Further, please find the CDG Host Statements that the IOUs generate to the CDG Host showing each Satellite's kWh applied credit and associated monetary value associated with those kWh credits.

With these data points, CDG Hosts (and their subscriber management agents like PowerMarket) can properly and effectively bill Satellites for the value received. Without it, CDG Hosts are unable to accurately bill CDG Satellites and CDG Satellites are unable to reconcile that they have been billed accurately for their CDG credits.

This is an existential threat to the success of PSEG LI's CDG program for NEM CDG Satellite's which are anticipated to be in the thousands of PSEG LI customers. This is because without transparency to the value received, the Satellite will struggle to reconcile the charges assessed by the CDG Host, causing confusion, frustration, and ultimately a lack of trust in CDG as an energy product, thereby impacting the viability of the CDG program as a whole. This is best appreciated in a sample use case:

Barbara enrolls in a NEM CDG project and after a month of operation, Barbara receives her first PSEG LI bill as a Satellite. Her first bill shows that her Total electricity used is 1000 kWh. Since this is her first month participating, there have been no banked kWh credits so her "Energy Credit Bank" shows 0 for Opening Balance and 0 for Applied to Current Bill. Barbara pays her PSEG LI bill for the 1000 kWh. PSEG LI shares a CDG Host Statement to the CDG Host that tells them that Barbara used 1,300 kWh at her location and had 300 kWh applied to her bill from her CDG project. The CDG Host now wants to bill Barbara for the value of her credits, giving her the guaranteed 10% discount. With the data provided to the CDG Host, the CDG Host cannot accurately do so because it does not know what the monetary value of the 300 kWh. For the sake of this example, let's say that the CDG Host makes an educated assumption on her retail rate and applies \$0.20/kWh and issues a bill to Barbara for \$54.00 (representing 90% of the \$60.00 worth of credits). Barbara calls up the CDG Host confused as to why she is being billed \$54.00. The CDG Host attempts to explain to her that she received 300 kWh credits to her bill and value of those credits were \$60 and to blindly trust it. But since she cannot see those kWh credits or discount of \$60 on her bill, and she can't validate that the charges assessed against her are correct. Despite the CDG Host assuring her that she was billed correctly (or relatively since the CDG Host didn't have the actual value of the those credits), Barbara is skeptical and concerned that she is being billed for something that she has no transparency to. She questions her participation in this program when she is only saving \$5-\$10 per month. [Residential customers are assumed to have annual usage at 9,500 kWh/year, and expected savings would be in the high single and low double digit amounts] Barbara says that the amount she is saving each month is not worth the confusion and uncertainty that she is getting the value promised. Barbara leaves the NEM CDG program and tells her friends and family about her negative experience.

This above use case is a real one. PowerMarket manages over 100 MW of CDG throughout New York, with 90% of all subscriber support calls deal with billing issues and reconciling charges assessed to subscribers for their CDG credits. Subscriber frustrations are real, and the cost benefit analysis can tip negatively if the process is not clear and simple. Fortunately, in the other IOUs we

can direct them to view their utility bill to see the credits they have received. Without this information, CDG Hosts have no ability to substantiate their charges to the customer.

While PowerMarket appreciates that the PSEG LI billing systems may be more advanced than the other IOUs, this cannot be justification for why CDG Hosts and CDG Satellite's are not shared the data needed to properly administer a NEM CDG project. LIPA and PSEG LI cannot ignore the practical realities of billing and support CDG Satellites participating in NEM CDG.

Therefore, we respectfully ask that LIPA require PSEG LI to present CDG Satellites with the kWh applied to their account each month as well as the monetary value of those credits, and present CDG Hosts with the monetary value of kWh credits applied to each CDG Satellite in the CDG Host Statement. If these updates require an interim solution from PSEG LI, we are open to such so long as our ultimate objectives are met, i.e. CDG Satellites can see the value they received from participating in the NEM CDG project on their PSEG LI bill, and CDG Hosts are provided the monetary value of kWh credits applied to CDG Satellite bills so that they can bill CDG Satellites with confidence and accuracy, as well as assist CDG Satellites in reconciling these charges on their own bill. We believe these deliverables to be reasonable as all other IOUs provide as such for NEM CDG projects and this request aligns with over all mission to make CDG on Long Island a successful and scalable program.

Thank you for your consideration.



Francis Zappone
Deputy Supervisor

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December 1, 2020

Ralph Suozzi, Chairman and
LIPA Board of Trustees
333 Earle Ovington Blvd.
Uniondale, NY 11553

Hon. Michelle L. Phillips
NYS Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223

Re: Community Distributed Generation ("CDG") net crediting

Dear Chairman Suozzi,

With assistance from Southampton Town's Community Choice Aggregation (CCA) Administrator, Joule Community Power, the following is submitted to the LIPA Board of Trustees and the Public Service Commission (PSC) concerning LIPA's proposal to modify its Tariff for Electric Service to allow for Community Distributed Generation ("CDG") net crediting.

Community Distributed Generation

It is a clear credit to the Authority that you have issued the net credit tariff for Community Distributed Generation that relies on credits totaling the Value of Distributed Generation. If this billing system is truly available early to mid 2nd quarter of 2021, as you have stated it will be, that is a triumph for developers and for ratepayers.

The details of how that program will be prepared are critical, however.

The tariff is slated to be available to developers (Sponsors) of CDG projects as of January 1st, 2021. The tariff outlines essential terms that developers will be offered but it is not a contractual document. The specific contract that developers will be asked to sign in order to take advantage of the tariff is likely being prepared by LIPA, as we speak. We anticipate one additional agreement is being prepared as well—when customers' data is provided to companies that will service these deals, the servicers must ensure that personal data remains confidential.

The drafting of these two contracts is also continuing elsewhere in the state by other regulated utilities. The earliest drafts of these documents have led to problems that threaten to delay, or hinder, program success. LIPA can avoid these issues if it drafts its contracts with a recognition of them.

1. Contract between LIPA and CDG developers. The contracts that the authority signs with renewable energy developers must be fair enough with respect to indemnification requirements placed on developers. For example, developers cannot be asked to cover for LIPA's negligence. That condition would simply ensure that potential developers simply do not engage—the tariff will yield no new construction of distributed solar power on the Long Island.

2. Contract between LIPA and data service firms. The data agreements that LIPA requires CCA Administrators receiving data must be reflective of Administrators' authority. Administrators are explicitly exempted from specific restrictions outlined in the Uniform Business Practices issued by the PSC^[1]. Elsewhere, utilities have prepared template contracts that would work quite well for other counterparties that do not have CCA authority but that will not work in the CCA process:

CCAs and their partners must receive data from utilities, in order to deliver the credit values to Sponsor and Subscriber, respectively. Some utility documents require the recipient of data and their partners, to attest that (s)he has active consent on the part of the account holder to receive the requisite data. An Administrator who has explicit PSC and DPS authorization to receive CDG personal data without individual consent, cannot attest to something that is not true. Further, they cannot force their sub-contractors to attest to something that subcontractors know is not correct. Forcing them to do so simply frustrates the stated will of the PSC and delays CCA's potential to save and to enable the construction of renewable power plants, for no valid reason whatsoever.

Constructive completion of these program details will ensure a vibrant market for renewable energy development on Long Island, generating local jobs, building a more resilient power system, and reducing air pollution from greenhouse gas emissions. Long Island residents will reliably save money each month without impacting LIPA's net electricity revenue streams one iota.

Further, it would be in LIPA's interest to develop a second supplemental tariff to cover another important group of developers ^[2].

Some clean community distributed generation gains its value through the ability to subtract kWhs from subscriber's utility bills, rather from crediting the bill at the "Value of Distributed Energy Resource ("VDER") "value stack.". These "remote net metered" facilities must also be offered a tariff similar to the above tariff offered to CDG that has been approved for VDER compensation.

It seems that issuance of this tariff has been delayed, likely because the bulk of LIPA's program will operate through VDER compensation. Billing system adjustments for this second set of developers will likely take LIPA a comparable amount of time and effort.

While it made sense to prioritize the development of systems that will scale in the years to come, in our view, it is now important to keep to a reasonable schedule for issuance of this "remote net metering" tariff as well. These projects were initiated by early entrants into the Long Island Distributed Energy market—they committed their intellectual and financial capital. LIPA's credibility on future programs is reduced if it does not support current and prior programs.

In this regard, we recommend a clear schedule on when this second tariff will be released and when billing systems will be enabled to support this second tariff as well.

[1] [https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/\\$FILE/September 2020 UBP CLEAN.pdf](https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8dd2b96e91d7447e85257687006f3922/$FILE/September%2020%20UBP%20CLEAN.pdf)

[2] On page 15 of the PSC Order issued on December 12, 2019, related to CASE 19-M-0463, the PSC clarifies that Net Credit billing must not only be available for VDER compensated projects, it must also be enabled and available for remote net metered projects that are classified as "Tranche 0" projects.

As it pertains to the current tariff, we strongly recommend the additions cited above relating to the contract between LIPA and CDG developers and the anticipated contract between LIPA and data service firms.

Moreover, it would be advantageous to provide a clear schedule on when remote net-metered qualified facilities will be offered a net credit tariff, associated bill system adjustments and related contracts between developer/LIPA and CCA Administrator/LIPA.

These changes are critical to achieving the tariff's full potential toward developing competitive markets on Long Island.

Respectfully,

A handwritten signature in black ink that reads "Francis Zappone". The signature is written in a cursive, flowing style.

Francis Zappone
Deputy Supervisor

cc:

Fred Thiele, New York State Assembly District 1
John Bouvier, Councilman Town of Southampton
Mike Gordon, Founder/CEO Joule Assets
Jessica Stromback, Managing Director Joule Assets