National Grid

The Narragansett Electric Company

PROPOSAL TO BID CAPACITY OF CUSTOMER-OWNED DG FACILITIES INTO THE FORWARD CAPACITY MARKET

Joint Pre-filed Testimony
and Schedules of:

Stefan Nagy and
Scott M. McCabe

November 18, 2016

Submitted to:

Rhode Island Public Utilities Commission
RIPUC Docket No. _____

Submitted by:

nationalgrid

Filing Letter

Jennifer Brooks Hutchinson
Senior Counsel

November 21, 2016

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Proposed National Grid Proposal to Bid Capacity of Customer-Owned DG Facilities into the Forward Capacity Market
Docket No. _____

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed the Joint Pre-filed Testimony and Schedules of Stefan Nagy and Scott M. McCabe in support of National Grid's proposal to bid the capacity of customer-owned distributed generation facilities (DG Facilities) into the ISO-NE Forward Capacity Market (FCM) and proposed ratemaking treatment of certain FCM costs and proceeds associated with this activity (FCM Proposal). The DG Facilities discussed in this filing refer to facilities owned and operated by customers who participate in the Company's Renewable Energy (RE) Growth Program pursuant to R.I. Gen. Laws § 39-26.6 et seq. and the RE Growth Program for Non-Residential Customers, RIPUC No. 2152-B, or who have executed standard contracts with the Company pursuant to the Distributed Generation Standard Contracts Act, R.I. Gen. Laws § 39-26.2.1 et seq.

The FCM is a wholesale electricity market within ISO-NE that uses price signals to ensure that the region maintains an adequate supply of capacity resources to meet electricity demand. The FCM ensures resource adequacy by providing payments to supply and demand resources to maintain and invest in new capacity to deliver power to the electric grid where it is most needed. As further explained in the testimony, the Company's initial strategy is to bid the capacity of solar DG Facilities into the FCM and assume a Capacity Supply Obligation that includes both Performance Incentive payments and penalties, as available through the ISO-NE Pay for Performance structure.[2]

In this filing, the Company is seeking the Public Utilities Commission's (PUC) approval (1) to recover all ISO-NE payments, fees, charges, or penalties (the Net FCM Proceeds) from the Company's participation in the FCM with DG Facilities; (2) share the Net FCM Proceeds with

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).
[2] Capitalized terms used herein and not otherwise defined shall have the meanings ascribed to those terms in Section I of the ISO New England Inc. Transmission, Markets, and Services tariff as referenced in the Pre-Filed Joint Testimony.

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customers at an 80/20 sharing allocation (80 percent to customers and 20 percent to the Company, either positive or negative); and (3) to recover all incremental administrative costs incurred as the result of performing activities related to bidding capacity of DG Facilities into the FCM, including, without limitation, administrative costs associated the implementation and ongoing operation of the FCM Proposal.

In addition, the Company requests the PUC's approval of revisions to three of the Company's existing tariffs, which are necessary to implement the Company's FCM Proposal. The Company is enclosing the following documents:

1. Clean and redlined versions of National Grid's proposed revisions to the RE Growth Program Cost Recovery Provision, RIPUC No. 2153 (Schedule NG-9);

2. Clean and redlined versions of National Grid's Long-Term Contracting for Renewable Energy Cost Recovery Provision, RIPUC No. 2127 (Schedule NG-10); and

3. Clean and redlined versions of revisions to National Grid's Long-Term Contracting for Renewable Energy Cost Recovery Reconciliation Provision, RIPUC No. 2125 (Schedule NG-11)

The tariff revisions include (1) a definition of Customer Share of Net FCM Proceeds; (2) a provision allowing for the recovery of actual incremental administrative costs incurred as the result of the Company's participation in the FCM, and (3) modifications to the reconciliation formulas, as detailed in Schedules NG-9, NG-10, and NG-11, as necessary to implement the Company's FCM Proposal.

In order for the Company to qualify its initial portfolio of commercially operational solar DG Facilities for participation in the next Forward Capacity Auction, Forward Capacity Auction 12 in June 2017, the Company is requesting PUC approval by February 1, 2017.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Leo Wold, Esq.
Jon Hagopian, Esq.
Steve Scialabba, Division

Joint Testimony of
Stefan Nagy &
Scott M. McCabe

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC DOCKET NO. _____
PROPOSAL TO BID CAPACITY OF CUSTOMER-OWNED DG FACILITIES
INTO THE FORWARD CAPACITY MARKET
WITNESSES: STEFAN NAGY
SCOTT M. MCCABE

JOINT PRE-FILED DIRECT TESTIMONY

OF

STEFAN NAGY

AND

SCOTT M. MCCABE

November 18, 2016

Table of Contents

I. Introduction and Qualifications of Stefan Nagy 1

II. Introduction and Qualifications of Scott M. McCabe 2

III. Purpose of Testimony 4

IV. The Forward Capacity Market 7

V. Company Proposal 8

VI. Company Strategy for FCM Participation 14

VII. Potential FCM Revenue 22

VIII. Cost Recovery 26

IX. Sharing of Net FCM Proceeds 32

X. Proposed Tariff Revisions 33

XI. Conclusion 34

I. Introduction and Qualifications of Stefan Nagy

Q. Mr. Nagy, please state your name and business address.

A. My name is Stefan Nagy, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what position?

A. I am employed by National Grid USA Service Company, Inc. (National Grid) as a Senior Analyst, Strategic Business, Policy, and Evaluation. In this role, I provide services to The Narragansett Electric Company d/b/a National Grid (the Company) and am responsible for managing the participation of the Company's portfolio of energy efficiency, combined heat and power, and solar distributed generation (DG) resources in the ISO New England Inc. (ISO-NE) Forward Capacity Market (FCM). In this role, my responsibilities include, among other things, developing market participation strategies, qualifying new projects in the market, submitting information required by ISO-NE for continued participation of projects in the market, and monitoring the performance of existing projects and the Company's overall portfolio.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Economics and a Bachelor of Science degree in Energy, Business and Finance from Pennsylvania State University. I also earned a Master of Science degree in Energy and Mineral Engineering from Pennsylvania State

University with an option in Energy, Management and Policy. The focus of my graduate education coursework was on the economics of wholesale energy markets, and for my Master's thesis, I conducted research on the ability of energy efficiency resources to engage in arbitrage through participation in the PJM Interconnection LLC capacity market. I have worked in my current role at National Grid managing the Company's participation in the FCM since October 2013.

Q. Have you previously testified before the Public Utilities Commission (PUC)?

A. No, I have not.

II. Introduction and Qualifications of Scott M. McCabe

Q. Please state your full name and business address.

A. My name is Scott M. McCabe, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. Please state your position.

A. I am the Manager of New England Electric Pricing, in the Regulation and Pricing Department of National Grid. My responsibilities include the design, implementation, and administration of rates and tariffs for the Company as well as those of Massachusetts Electric Company and Nantucket Electric Company.

Q. Please describe your educational background and training.

A. I graduated from Bowdoin College in Brunswick, Maine with a Bachelor of Arts degree in Economics, and Government and Legal Studies in 1991.

Q. Please describe your professional experience.

A. From 1991 to 1999, I was employed by Bay State Gas Company (Bay State Gas), headquartered in Westborough, Massachusetts. At Bay State Gas, I held several positions, beginning as an intern for the Marketing and Sales Group in September 1991 and was promoted to Associate Planning Analyst for the same group in January 1993. In August 1993, I joined the Demand Side Management (DSM) department as a program manager responsible for the implementation of Bay State Gas' commercial and multifamily DSM Programs. In August 1996, I joined EnergyUSA, an unregulated affiliate of Bay State Gas, as a Senior Financial Analyst and in December 1997 was promoted to Manager of Product Support. In January 1999, I rejoined Bay State Gas as Revenue Control and Analysis Supervisor. From May 1999 through April 2001, I worked for the Massachusetts Technology Collaborative as Project Manager for the Massachusetts Renewable Energy Trust. I joined National Grid in April 2001 as Senior Analyst in the Energy Efficiency Services Group. I transferred to Regulation and Pricing in October 2002. In July 2008 I was promoted to Principal Analyst and in July 2013 became a Principal Program Manager. In May of 2014, I was promoted to my current position.

Q. Have you previously testified before PUC?

A. Yes.

III. Purpose of Testimony

Q. What is the purpose of your joint testimony?

A. The purpose of our joint testimony is to present the Company's proposal to bid the capacity of customer-owned distributed generation facilities (DG Facilities) into the ISO-NE FCM and to propose ratemaking treatment of certain FCM costs and proceeds associated with this activity (FCM Proposal). The DG Facilities discussed in this testimony refer to facilities owned and operated by customers who participate in the Company's Renewable Energy (RE) Growth Program pursuant to R.I. Gen. Laws § 39-26.6 et seq. and the RE Growth Program for Non-Residential Customers, RIPUC No. 2152-B (RE Growth Tariff), or who have executed standard contracts with the Company pursuant to the Distributed Generation Standard Contracts (DGSC) Act, R.I. Gen. Laws § 39-26.2.1 et seq. As detailed below, in this filing, the Company seeks the PUC's approval: (1) to recover all ISO-NE payments, fees, charges, or penalties from participation in the FCM with DG Facilities, resulting in Net FCM Proceeds;[1] (2) to share Net FCM Proceeds with customers, with 80 percent of Net FCM Proceeds credited or charged to customers within the respective cost recovery factors of each distributed

[1] "Net FCM Proceeds" refer to all payments received from ISO-NE for participation in the FCM, net of any ISO-NE fees, charges, or penalties that may be assessed under the current or future FCM market rules.

generation program, and 20 percent of Net FCM Proceeds, either positive or negative, retained by the Company; (3) to recover all incremental administrative costs incurred as the result of performing activities related to bidding capacity of DG Facilities into the FCM, including, without limitation, administrative costs associated the implementation and ongoing operation of the FCM Proposal; and (4) of the proposed tariff revisions to three of the Company's existing tariffs necessary to implement the Company's FCM Proposal, as discussed below.

Our joint testimony also summarizes the revisions to the Company's RE Growth Program Cost Recovery (REGPCR) Provision, RIPUC No. 2153, Long-Term Contracting for Renewable Energy Cost Recovery (LTCRER) Provision, RIPUC No. 2127, and Long-Term Contracting for Renewable Energy Cost Recovery (LTCRER) Reconciliation Provision, RIPUC No. 2125, collectively the "Recovery and Reconciliation Factors," that are needed to implement the Company's FCM Proposal.

Q. Is the Company requesting the PUC's approval of this FCM Proposal by a specific date?

A. Yes, it is. The Company is requesting PUC approval of the Company's FCM Proposal by February 1, 2017. As discussed later in our testimony, the Company wishes to qualify its initial portfolio of commercially operational solar DG Facilities for participation in the

next Forward Capacity Auction,[2] Forward Capacity Auction 12, in order to maximize value for its customers. Final qualification materials for Forward Capacity Auction 12 are due to ISO-NE in June 2017, and the Company will need to begin preparing qualification materials in February 2017 in order to successfully submit materials for qualification in June 2017.

Q. How is your joint testimony organized?

A. Our testimony is organized as follows: Sections I and II of the testimony provide introduction and background information; Section III describes the purpose of the testimony; Section IV describes the FCM and its function; Section V describes the Company's FCM Proposal; Section VI describes the Company's FCM bidding strategy; Sections VII and VIII describe the potential revenue and costs; Section IX describes the Company's sharing proposal; Section X contains a description of proposed tariff revisions; and Section XI is a conclusion.

Q. Are you sponsoring any schedules to your joint testimony?

A. Yes. We are sponsoring the following schedules:

[2] Capitalized terms used herein but not otherwise defined shall have those meanings ascribed in Section I of the ISO New England Inc. Transmission, Markets, and Services tariff at: http://www.iso-ne.com/participate/rules-procedures/tariff.

Schedule	Description
Schedule NG-1	Forward Capacity Auction 12 Timeline
Schedule NG-2	Projected Installed Capacity
Schedule NG-3	Projected Qualified Capacity
Schedule NG-4	Projected Net Customer Benefit – Base Case
Schedule NG-5	Projected Net Customer Benefit – Base Case v. No Capacity Supply Obligation
Schedule NG-6	Projected Net Customer Benefit – Base Case Monte Carlo Scenarios
Schedule NG-7	Projected Net Customer Benefit – Sensitivity Case Monte Carlo Scenarios
Schedule NG-8	Estimated Ongoing Administrative Costs
Schedule NG-9	Proposed REGCR Provision
Schedule NG-10	Proposed LTCRER Provision
Schedule NG-11	Proposed LTCRER Reconciliation Provision

IV. The Forward Capacity Market

Q. Please describe, generally, the Forward Capacity Market and its function.

A. The Forward Capacity Market, or "FCM", is a wholesale electricity market within ISO-NE that uses price signals to ensure that the region maintains an adequate supply of capacity resources to meet electricity demand. The FCM ensures resource adequacy by providing payments to supply and demand resources to maintain and invest in new capacity to deliver power to the electric grid where it is most needed.[3]

[3] "Resource adequacy" addresses the ability of the grid's generating capacity to adequately meet demand without incurring blackouts in times of very high load.

The FCM functions as a three-year forward, auction-based market.[4] Participants bid into a competitive auction each year. Bids that are less than or equal to the auction price will clear the auction. All bids that clear the auction are assigned a Capacity Supply Obligation, which requires that they deliver the capacity three years into the future and for the duration of at least a one-year Capacity Commitment Period.[5] For example, the most recent auction occurred in February 2016 and was for the delivery of capacity from June 1, 2019 to May 31, 2020. Any participant that meets its Capacity Supply Obligation on time will receive monthly base payments equal to the capacity clearing price multiplied by the megawatts (MW) of capacity being delivered. In addition to the monthly base payments, participants may receive incentive payments and/or penalties (as described in more detail in Section VI below) based on their performance[6] during times of system shortage.

V. Company Proposal

Q. Please explain the Company's FCM Proposal.

[4] Detailed information regarding the rules and regulations of the FCM is available in Section III of the ISO New England Inc. Transmission, Markets, and Services tariff at: http://www.iso-ne.com/participate/rules-procedures/tariff.

[5] A "Capacity Commitment Period" is a one-year period, from June 1 through May 31 of the following calendar year, for which ISO-NE procures capacity in the Forward Capacity Auctions.

[6] As described in more detail in Section VI, participants may be eligible for incentive payments during times of system shortage even without acquiring a Capacity Supply Obligation in the FCM.

A. The Company is proposing to bid the capacity of certain DG Facilities into the FCM as well as the ratemaking treatment of this activity. The Company's bidding strategy, and any subsequent participation in the FCM with DG Facilities, is dependent upon the PUC's approval of the Company's FCM Proposal. PUC approval of the Company's FCM Proposal would allow the Company to: (1) recover all ISO-NE payments, fees, charges, or penalties from participation in the FCM with DG Facilities, resulting in Net FCM Proceeds, (2) share with customers in the Net FCM Proceeds at an 80/20 sharing allocation (80 percent to customers and 20 percent to the Company); and (3) recover all incremental administrative costs incurred as the result of performing activities related to bidding capacity of DG Facilities into the FCM, including, without limitation, administrative costs associated the implementation and ongoing operation of the FCM Proposal, in the Recovery and Reconciliation Factors. The Company is essentially proposing to reflect 80 percent of Net FCM Proceeds and the incremental administrative costs stated in (3), above (together referred to as the Net Customer Benefit) in the Recovery and Reconciliation Factors for the RE Growth Program and DGSC program.

As a whole, the Company's FCM Proposal reduces the risk to customers of the Company participating in the FCM with third party-owned facilities and incentivizes the Company to maximize the proceeds from the participation of these assets in the FCM, while sharing appropriately in the risk for doing so. The proposal would also enable the Company to

pursue its strategy to monetize the capacity of qualified DG Facilities in the FCM and maximize the potential value of such capacity for the benefit of its customers.

As discussed in more detail below, the Company has developed an initial strategy to bid the capacity of certain solar DG Facilities into the FCM to receive Net FCM Proceeds, which the Company estimates to be approximately $36.9 million, based on the current capacity expected from the two DG programs operated by the Company.

Q. Is PUC approval required in order for the Company to bid the capacity of DG Facilities into the FCM?

A. No. The Company already has the regulatory authority to bid the capacity of DG Facilities into the FCM. The DGSC and RE Growth Program tariff provisions and contract provisions already approved by the PUC allow, but do not require, the Company to bid the capacity of non-residential DG Facilities into the FCM, and to use those payments to offset the total cost of the DG programs that is recovered from all customers through the Recovery and Reconciliation Factors for each program. In this filing, the Company is seeking PUC approval for the FCM Proposal and the corresponding tariff revisions that would enable the implementation of the proposal and the disposition of Net Customer Benefit resulting from the proposal.

Q. Has the Company already qualified and bid capacity of DG Facilities in Rhode Island into the FCM?

A. No.

Q. Please explain why the Company is proposing to bid the capacity of DG Facilities into the FCM.

A. The Company has gained experience with the market through its qualification of capacity associated with energy efficiency and solar facilities. The Company has qualified energy efficiency resources in all Forward Capacity Auctions since the inception of the FCM, and has qualified solar resources, which are owned by the Company's affiliate Massachusetts Electric Company, in Forward Capacity Auctions 4 through 11. Based on this experience, the Company has evaluated the benefits, risks, and administrative requirements presented by current market conditions in the FCM and concluded that bidding the capacity of certain DG facilities into the FCM could yield significant value for customers.

Non-residential RE Growth facilities and all DGSC facilities in Rhode Island are the functional equivalent of stand-alone generators, which are independently metered and can successfully qualify for and bid into the FCM, if they meet other ISO-NE requirements. Recent changes in market conditions have increased the value of this capacity. Until May 30, 2014, the FCM was in a state of flux, and FCM auction prices, with some notable exceptions, were relatively low, never reaching above $4.50 per kilowatt-month (kW-month). The interim FCM rule changes were finalized on May 30, 2014. Under

current market conditions, FCM prices have increased, with prices for new resources in Forward Capacity Auction 9 ranging from $9.55 per kW-month to $17.728 per kW-month (depending on the capacity zone where the resource is located). Prices for all resources in Forward Capacity Auction 10 were set at $7.03/kW-month. Direct participation in the FCM is the only method by which the capacity of independently-metered DG Facilities in Rhode Island can be monetized. For example, in the case of solar DG Facilities, ISO-NE conducts an annual Solar Photovoltaic (PV) forecast as part of its net load forecasting process. Solar PV capacity that is modeled as behind-the-meter is incorporated into the net load forecast and reduces the Installed Capacity Requirement,[7] effectively reducing the amount of capacity that customers must purchase through the FCM. Conversely, ISO-NE does not adjust the Installed Capacity Requirement for independently-metered Solar PV capacity that participates in the ISO-NE wholesale energy market because these resources are expected to participate directly in the FCM. Under this forecasting treatment, the capacity of solar DG Facilities in Rhode Island, which are directly metered under the DGSC and RE Growth Programs, is not reduced from the Installed Capacity Requirement, and can only be monetized through direct participation in the FCM.

[7] For a detailed report on the determination of the Forward Capacity Auction 10 Installed Capacity Requirement, please refer to the "ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period" at http://www.iso-ne.com/static-assets/documents/2016/01/icr_values_2019_2020_report_final.pdf,

The above factors provide support for the Company's determination that bidding DG Facilities into the FCM, with its proposed FCM Proposal in place, is likely to be beneficial for customers and would capture the value of otherwise unutilized capacity.

Q. Does the Company intend to bid the capacity for all DG Facilities?

A. Initially, the Company intends to qualify and bid only non-residential solar DG Facilities with a nameplate capacity of at least 250 kilowatts (kW). ISO-NE does not allow generation capacity less than 100 kW to participate in the market under its current rules. Typically, ISO-NE qualifies solar facilities in the FCM at approximately 35% of the nameplate AC capacity, making 250 kW an approximate threshold for the participation of solar facilities. In addition, the Company does not obtain title to the capacity from residential customer systems. The Company's existing meters for the non-residential solar DG Facilities can be used to meet the ISO-NE reporting requirements for DG in the FCM.

If the ISO-NE market rules change such that the solar DG Facilities smaller than 250 kW may participate in the FCM, the Company will evaluate its ability to efficiently qualify and bid all non-residential solar DG Facilities with a nameplate capacity of at least 25 kW and will consider doing so if the Company estimates that this group of facilities could generate a net benefit to customers.

While the Company's FCM Proposal, if approved, would begin through participating in the FCM with solar DG Facilities' capacity, the Company is not intending to limit the manner in which it may choose to participate in the FCM with DG Facilities (including technologies other than solar) or the applicability of the FCM Proposal to such participation. The Company will evaluate projects on an individual basis to determine whether or not each project would be viable in the market, how they will participate in the market (i.e., whether or not to take on a Capacity Supply Obligation), and will also continue to assess the inclusion of other technologies in any future FCM bidding portfolios.

VI. Company Strategy for FCM Participation

Q. What is the Company's strategy for bidding the capacity of solar DG Facilities into the FCM?

A. The Company's initial strategy is to bid the capacity of solar DG Facilities into the FCM and assume a Capacity Supply Obligation that includes both Performance Incentive payments and penalties, as available through the Pay for Performance structure recently instituted by ISO-NE's new market rule.[8]

[8] For a detailed description of ISO-NE's implementation of the new rules, please refer to ISO-NE's compliance filing on the rule change, "*ISO New England Inc*., Docket Nos. ER14-2419-__, EL14-52-__; 30-Day Compliance Filing to Revise Tariff section III.13.7" at https://www.iso-ne.com/static-assets/documents/2014/11/er14-2419-002_11-3-14_two-settlement_market_compliance_filing.pdf

Q. Please explain the Pay for Performance structure.

A. The implementation of the Pay for Performance structure creates two distinct options for market participation in the FCM. In the first option, participants may bid into a Forward Capacity Auction and take on a Capacity Supply Obligation, as described above. If participants deliver on their Capacity Supply Obligation, they are entitled to monthly base payments. Additionally, participants with a Capacity Supply Obligation are obligated to perform during Capacity Scarcity Conditions,[9] as per the Pay for Performance rule, and are eligible for Performance Incentive payments and penalties (Capacity Supply Obligation Market Participation Option). In the second option, participants do not take on a Capacity Supply Obligation, but simply report to ISO-NE the resource's energy production that is coincident with a Capacity Scarcity Condition for

[9] Capacity Scarcity Conditions, as defined by Section III.13.7.2.1 of the ISO New England Inc. Transmission, Markets, and Services tariff, can occur at any time and are determined based on system constraints that lead to a shortage of operating reserve capacity. The Pay for Performance rule includes a balancing ratio, which is set as the ratio of the total system load to the Installed Capacity Requirement at the time of a Capacity Scarcity Condition. During the Capacity Scarcity Condition, all capacity resources with a Capacity Supply Obligation are required to perform at a level equal to or greater than their Capacity Supply Obligation, as scaled by the balancing ratio. For example, if the system load at the time of a Capacity Scarcity Condition is 15,000 MW and the Installed Capacity Requirement is 30,000 MW, the balancing ratio is 0.5, which requires that all capacity resources perform at or above half of their Capacity Supply Obligation. Any resource that performs at a level that is lower than the required fraction of its Capacity Supply Obligation will pay a Performance Incentive penalty, equal to the payment rate ($/MWh) scaled by the level of underperformance. Likewise, any resource that exceeds its scaled Capacity Supply Obligation will receive a Performance Incentive payment equal to the payment rate scaled by the level of over-performance. The payment rate starts at $2,000/MWh and will ramp up to $5,455/MWh by 2024.

the purpose of receiving Performance Incentive payments (Alternative Market Participation Option).[10]

Q. Which option is the Company planning to pursue as part of its strategy?

A At this time, the Company intends to participate in the FCM under the Capacity Supply Obligation Market Participation Option because, although it will require more planning and active oversight, the Company's analysis, presented later in this testimony, indicates that taking on a Capacity Supply Obligation, with monthly base payments and Performance Incentive payments, is expected to bring significantly more value than not taking on a Capacity Supply Obligation.

Q. What is the risk of Performance Incentive penalties under the Capacity Supply Obligation Market Participation Option?

A. The Company projects that, after mitigating certain risks and assuming careful management of the FCM portfolio, once the portfolio has reached a steady state,[11] there is less than a 1.5% probability of realizing a net loss in the market from Performance

[10] If participants do not take on a Capacity Supply Obligation, they are not eligible to receive monthly base payments and there is no obligation to perform during Capacity Scarcity Conditions, which means fewer incentives for performance and no penalties for under-performance. Instead, the resources can be registered without a Capacity Supply Obligation and, if there are Capacity Scarcity Conditions coincident with solar production, they could receive Performance Incentive payments for the energy production during the Capacity Scarcity Condition.

[11] The term "steady state" in this testimony refers to a state in which all of the DG Facilities in the Company's initial FCM portfolio have become commercially operational and active in the FCM, such that the projected growth of the Company's capacity, and the associated Net FCM Proceeds, has plateaued.

Incentive penalties on an annual basis. Historically, Capacity Scarcity Conditions have occurred during the day in the summer. Because solar DG Facilities are likely to be meeting or exceeding their Capacity Supply Obligations at such times, this should generally result in Performance Incentive payments as opposed to Performance Incentive penalties. Moreover, even if there are some Performance Incentive penalties, it is unlikely that the penalties would outweigh the base payments, which constitute roughly 95 percent of the capacity revenue in a given year (with Performance Incentive payments accounting for the remaining 5 percent).

Q. Are there any risks associated with the Alternative Market Participation Option?

A. Yes, there are potential risks. Although the Alternative Market Participation Option would carry no risk of Performance Incentive penalties (because there is no Capacity Supply Obligation), there is still some degree of risk that the costs will outweigh the benefits. Namely, if there are few or no Capacity Scarcity Conditions coincident with solar performance in a given year, the administrative costs to register the resources in the market could exceed the benefits of any Performance Incentive payments under the Alternative Market Participation Option.

Q. What work would the Company perform when bidding DG Facilities into the FCM?

A. Although the DG Facilities that the Company would bid into the FCM are or will be customer-owned and operated, the Company would act as the Lead Market Participant in

the FCM.[12] As the Lead Market Participant, the Company would, among other things, submit: (1) resource qualification materials; (2) Forward Capacity Auction bids; (3) Annual Reconfiguration Auction[13] bids, if applicable; (4) quarterly critical path schedule updates; and (5) monthly performance data. The Company will attempt to qualify DG Facilities as New Intermittent Generating Resources for the earliest feasible Forward Capacity Auction. For the Company's initial participation in the FCM with solar DG Facilities, a detailed timeline of the qualification and auction process for Forward Capacity Auction 12 is shown in Schedule NG-1. If the resources clear in a Forward Capacity Auction, the Company may also attempt to qualify and have them clear in an Annual Reconfiguration Auction for an earlier Commitment Period. The Company will also continually assess its bidding strategy and participation in the FCM, and make necessary adjustments, including, without limitation, monitoring the production and revenue associated with its DG Facilities FCM portfolio in order to maximize revenue and actively mitigate the risk of Performance Incentive penalties.

[12] According to Section I.2.2 of the ISO-New England Inc. "Transmission, Markets, and Services" tariff at: http://www.iso-ne.com/participate/rules-procedures/tariff, "For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource."

[13] Reconfiguration Auctions are secondary auctions that occur annually, between the Forward Capacity Auction and the start of the associated Capacity Commitment Period, as well as monthly during the Capacity Commitment Period. These auctions allow FCM participants to adjust their Capacity Supply Obligations, for the relevant Capacity Commitment Period, to monetize capacity that did not clear in the Forward Capacity Auction or "buy out" of an obligation that they may not be able to meet.

Q. How will the Company mitigate the risk of Performance Incentive penalties?

A. The Company intends to qualify resources in a manner that limits the risk of realizing Performance Incentive penalties for underperformance. For instance, solar DG Facilities would be qualified as "Summer-Only" Intermittent Generating Resources, which will only have a Capacity Supply Obligation for the months of June, July, August, and September. This will eliminate the risk that Capacity Scarcity Conditions in the winter, when solar production is lower, will lead to Performance Incentive penalties for the solar DG Facilities. Prior to qualification, the Company will conduct a thorough review of each DG Facility's projected and/or historic performance to appropriately size the facility's Capacity Supply Obligation and reduce the risk of underperformance relative to the Capacity Supply Obligation. Additionally, the Company will only qualify DG Facilities for the FCM once the facilities are operating in order to eliminate the risk of obtaining a Capacity Supply Obligation for a DG Facility that never becomes operational. The Company will continuously monitor the performance of all facilities that have been entered into the FCM and obtained a Capacity Supply Obligation. The Company will evaluate each project that is determined to be underperforming relative to its Capacity Supply Obligation to determine if the underperformance is expected to persist. Evaluation steps may include analysis of historic performance and weather data, discussions with the facility owner, and any other analysis deemed appropriate. If the Company's evaluation determines that a facility will continue to underperform relative to its Capacity Supply Obligation, the Company may: (1) remove the facility from future

auctions through a process called de-listing; or (2) remove the facility from the current Commitment Period by submitting a demand bid on behalf of the resource in an Annual or Monthly Reconfiguration Auction, effectively transferring the Capacity Supply Obligation to another party.[14] The Company's initial FCM bidding strategy will be periodically assessed, and the Company will make adjustments and changes, as necessary.

Q. How soon could the Company begin bidding resources into the FCM and receiving revenue?

A. If the Company's FCM Proposal is approved by the PUC, the Company intends to begin bidding resources into the FCM as it becomes feasible. Once a DG Facility becomes commercially operational, the Company can include it in the next FCM qualification period. The next Forward Capacity Auction would be one year later. As previously stated, the FCM is a three-year forward market, but once a resource is qualified, it may attempt to clear an Annual Reconfiguration Auction for an earlier Commitment Period,

[14] Changes to the portfolio would be factored into the Net FCM Proceeds, as hereinafter defined. For example, without limitation, in scenario number (2), the net financial impact (I) of bidding into the Forward Capacity Auction and subsequently shedding that Capacity Supply Obligation through a reconfiguration auction is the difference between the Forward Capacity Auction Clearing Price (P_{FCA}) and the Reconfiguration Auction Clearing Price (P_{RA}), multiplied by the MWs of Capacity Supply Obligation (MW_{CSO}), such that: $I = [(P_{FCA}) – (P_{RA})]*(MW_{CSO})$.

making it eligible for earlier payments.[15] If the PUC approves the Company's FCM Proposal, the Company will initiate its FCM participation by qualifying commercially operational solar DG Facilities in 2017 for participation in Forward Capacity Auction 12 in 2018.

Q. How would customers benefit from the Company's FCM Proposal?

A. In the year the Company will begin to receive Net FCM Proceeds as a result of its participation in the FCM, the Company will include an estimate of the Net FCM Proceeds in the Recovery and Reconciliation Factors that would be in effect during that period. Therefore, over time, the Company's FCM Proposal has the potential to provide value to customers by reducing the growing cost of the DG programs in Rhode Island. In 2015, actual net Long-Term Contracting costs for the Company's distribution customers were $12.3 million,[16] and actual costs for the RE Growth 2015 Program Year were near $1 million.[17] During 2016, the Company's LTCRER Factors have been designed to

[15] For example, if a new DG Facility begins operating in 2016, it could be qualified in 2017, be entered into Forward Capacity Auction 12 in 2018, and if it clears in the auction, it would be scheduled to begin receiving payments from Forward Capacity Auction 12 in June 2021. Also, if a facility clears in a Forward Capacity Auction, it can also be entered into an Annual Reconfiguration Auction for an earlier Commitment Period, and if it clears the Annual Reconfiguration Auction, it could begin receiving payments as early as 2018.

[16] Docket 4599, 2016 Electric Retail Rate Filing, Schedule ASC-18, Page 1, Column (c) total; Docket 4599, 2016 Electric Retail Rate Filing, Schedule ASC-16, Page 1, Column (a) and (c) totals.

[17] Docket 4626, RE Growth Factor Filing, Schedule NG-3, Page 1, Line (2).

recover $13.0 million of costs and the RE Growth Factors implemented on October 1, 2016 are based on $2.5 million of costs.

VII. Potential FCM Revenue

Q. Has the Company estimated the size of the solar DG portfolio available for participation in the FCM?

A. Yes. The Company has developed a projection of its portfolio of qualifying solar DG Facilities based on the historic and future enrollment targets that have been approved for the RE Growth Program and the DGSC program. Schedules NG-2 and NG-3 depict the installed and qualified capacity,[18] respectively, under the RE Growth Program[19] and DGSC enrollment schedules.

Q. Has the Company estimated the Net Customer Benefit associated with the Company participating in the FCM with solar DG Facilities?

A. Yes. Once the portfolio of solar DG Facilities has reached a steady state (estimated proceeds ramp up as DG capacity comes online through 2021), the Company estimates, with the Capacity Supply Obligation Market Participation Option, that the annual Net

[18] Qualified capacity refers to the amount of capacity that is allowed to be bid into the market for a given amount of installed nameplate capacity. Solar facilities are typically qualified in the market at roughly 35 percent to 40 percent of the installed nameplate capacity.

[19] The projected RE Growth portfolio is based on the currently approved RE Growth program through 2019. If the program receives an extension in the future, the Company would seek to qualify and monetize the additional capacity in the FCM through the application of the strategy described in this testimony.

Customer Benefit that would be passed on to customers could be approximately $1.1 million. The Net Customer Benefit consists of two components: (1) the Customer Share of Net FCM Proceeds, which is 80 percent of the Net FCM Proceeds, as defined earlier in this testimony, and (2) incremental administrative costs incurred as a result of the Company performing the tasks required to qualify, bid, and monitor participation of DG Facilities in the FCM. The lifetime Net Customer Benefit of the solar DG Facilities has an estimated net present value (NPV) of $10.9 million and a nominal value of $22.1 million.[20]

The Company also estimated the proceeds associated with the Alternative Market Participation Option and estimates that once the portfolio of solar DG Facilities has reached a steady state, the Net Customer Benefit would be approximately $50,000. The lifetime Net Customer Benefit of the Alternative Market Participation Option has an estimated NPV of $430,000. Based on this analysis, the Company has concluded that the Capacity Supply Obligation Market Participation Option is the preferred strategy.

Q. Please explain how the Company developed its estimate of the Net FCM Proceeds?

A. The Company developed the estimate of Net FCM Proceeds based on the application of its initial FCM bidding strategy to its projected portfolio of solar DG Facilities under

[20] Lifetime Net Customer Benefit is calculated as the cumulative annual Net Customer Benefit over the life of the DG Facilities.

several scenarios. Schedule NG-4 presents projections of the potential Net Customer Benefit for each portfolio under the Capacity Supply Obligation Market Participation Option, using the same set of base projection assumptions for capacity market prices and Performance Incentive payments.[21]

Schedule NG-5 takes the total portfolio and compares the expected value[22] from the Capacity Supply Obligation Market Participation Option to the Alternative Market Participation Option. As described above, once the solar DG portfolio reaches a steady state, the Company has estimated that its initial FCM bidding strategy could yield an annual Net Customer Benefit of approximately $1.1 million under the Capacity Supply Obligation Market Participation Option, versus an annual Net Customer Benefit of approximately $50,000 under the Alternative Market Participation Option.

Schedule NG-6 takes the total portfolio and depicts the upper and lower bounds of the Net Customer Benefit that could occur in 1 out of every 100 years from an unusually high amount of Performance Incentive payments (upper-bound) or an unusually high amount

[21] The base assumptions used in these projections, under the Capacity Supply Obligation Market Participation Option, are a capacity price of $11.64 per kW-month, which is equal to the Net Cost of New Entry for Forward Capacity Auction 11, and an average amount of Performance Incentive payments. This is referred to as the "Base Case" in the Schedules NG-4, NG-5, and NG-6.

[22] "Expected value" refers to the probability-weighted average and is based on modeled projections. In the case of the proposed strategy, it refers to the probability-weighted average projection of Net FCM Proceeds.

of Performance Incentive penalties (lower-bound), as determined by the Company's Monte Carlo simulations.[23] The graph in Schedule NG-6 shows that, assuming an expectedly high capacity price in the future ($11.64 per kW-month, which is equal to the Net Cost of New Entry for Forward Capacity Auction 11), even if the resources incurred an unusually high level of Performance Incentive penalties, the Performance Incentive penalties are not expected to outweigh the annual revenue from the monthly base payments.

Schedule NG-7 takes the total portfolio and represents a sensitivity case that assumes a low capacity price ($3.399/kW-month, which represents the historic average FCM clearing price for the Rest-of-Pool capacity zone in Commitment Periods 1 through 7),[24] and average Performance Incentive payments. It also includes an unusually high amount of Performance Incentive payments (upper-bound) or an unusually high amount of Performance Incentive penalties (lower-bound), that could occur in 1 out of every 100 years. In this analysis, the expected value and upper-bound scenarios still resulted in some Net FCM Proceeds, but the lower-bound scenario would result in a negative Net Customer Benefit, which could peak at an overall cost to customers of approximately

[23] A Monte Carlo simulation is a statistical simulation technique that uses repeated sampling of a random variable to obtain a distribution of numerical results. The Company used this technique to estimate the revenue and risk exposure associated with the Pay for Performance structure.

[24] The average price for the Rest-of-Pool zone in Commitment Period 1 through Commitment Period 7 was chosen for the sensitivity case because these auctions cleared during conditions of capacity surplus, before New England became a capacity constrained region.

$360,000. However, if these conditions persisted, the Company could de-list the facilities as discussed in Section VI, above.

Q. What has the Company concluded based on its analysis?

A. The Company's conclusion is that its FCM Proposal to bid the capacity of DG Facilities into the FCM and assume a Capacity Supply Obligation would provide significant value to customers and is expected to provide a greater net benefit to customers than the Alternative Market Participation Option.

VIII. Cost Recovery

Q. What costs is the Company requesting to recover as part of its FCM Proposal?

A. The Company requests PUC approval to recover: (1) all ISO-NE fees, payments, charges, or penalties from participation in the FCM with DG Facilities, resulting in Net FCM Proceeds, of which the Company proposes a sharing between customers/Company of 80 percent/20 percent and (2) all incremental administrative costs incurred as the result of performing activities related to bidding the capacity of DG Facilities into the FCM, including, without limitation, administrative costs associated the implementation and ongoing operation of the FCM Proposal. The Company will reflect customers' share of 80 percent of Net FCM Proceeds as an offset to annual expenses in the annual

reconciliations of the RE Growth Program and DGSC program Recovery and Reconciliation Factors.

Q. What are the anticipated administrative costs associated with the Company's participation in the FCM?

A. The Company anticipates that there will be annual on-going administrative costs associated with qualifying, bidding, monitoring, and reporting on the portfolio of DG Facilities. The Company expects that managing the Company's initial FCM portfolio would require one to two incremental full-time equivalent (FTEs) resources, either employees or contractors, at an aggregate cost of between $138,390 and $276,780 per year.[25] As shown in Schedule NG-8, the Company's analysis of the projected portfolio has estimated annual ongoing administrative costs based on the projected number of projects to be qualified and managed in the FCM.[26] These estimated ongoing

[25] This projection assumes Case 1 in Schedule NG-8, as described in footnote 26 below. The analysis presented in this testimony assumes an annual cost per FTE of $138,390. This represents the fully burdened cost of an incremental employee with a base salary of $80,000 per year and labor overheads, excluding pension and Pension Benefits Other than Pension, of 72.99% of the base salary.

[26] Schedule NG-8 presents the Company's estimates of the number of FTEs, and the associated administrative costs, necessary to implement the Company's FCM Proposal under three cases that consider varying estimates of the number of DG Facilities in the Company's portfolio. Case 1 assumes that commercial-scale (251-999 kW) and large-scale (1,000 – 5,000 kW) solar facilities under the RE Growth Program have an average size near the median of each respective size range, while Case 2 assumes that these solar facilities have a smaller average size (resulting in more projects to meet the program MW targets) and Case 3 assumes that the Company may qualify solar facilities that are smaller than 250 kW. While the Company's analysis presented above assumes the administrative costs depicted in Case 1, Cases 2 and 3 demonstrate that these costs may vary in practice based on the number of projects that are enrolled in the Company's FCM portfolio. Note that the number of DGSC facilities remain constant in Cases 1, 2 and 3, as they have already been enrolled in the program.

administrative costs have been factored into the Company's projections of annual net benefits in Schedules NG-4, NG-5, NG-6, and NG-7. As shown in Schedule NG-8, the Company's actual administrative costs necessary to implement the Company's FCM Proposal may vary based on the actual number of DG Facilities in the Company's initial FCM portfolio or if the Company's portfolio expands to include DG Facilities that were not incorporated in the estimates of the Company's initial FCM portfolio.

It is important to note that due to the three-year forward nature of the FCM, the Company will incur incremental administrative costs that will not be offset by Net FCM Proceeds in the first few years before the Capacity Supply Obligations acquired in the Forward Capacity Auctions take effect. For instance, the administrative costs in the first five years of the Company's projected portfolio are estimated to be approximately $830,000,[27] which is more than half of the expected Net FCM Proceeds of $1.2 million and more than three times the estimated Company incentive of $250,000, under the proposed 20 percent sharing, in the same timeframe.

While at this time the Company does not anticipate any start-up administrative costs, should the Company incur any start-up costs as a result of Company's participation in the

[27] Refer to Schedule NG-8 for an illustration of the estimated ongoing administrative costs associated with the Company's FCM Proposal. The administrative cost estimate presented here is based on Case 1 in Schedule NG-8, as described in footnote 26 above.

FCM with DG Facilities, the Company will include such costs in the Recovery and Reconciliation Factors for the RE Growth Program and the DGSC program. Potential start-up costs include costs incurred as a result of any Company database changes needed to initiate the Company's participation in the FCM with DG Facilities.

Q. How is the Company proposing to recover the incremental administrative costs associated with its FCM Proposal?

A. The Company proposes to recover the incremental administrative costs associated with the bidding of the DGSC projects in the FCM through the LTCRER tariff and, to recover the incremental administrative costs associated with the bidding of the RE Growth Program projects into the FCM through the RE Growth Program Cost Recovery Provision. The Company will allocate costs between RE Growth Program factors and LTCRER factors based on the percentage of the MWs of capacity that are qualified to participate in the FCM under each respective program. Recovering the administrative costs associated with the Company's FCM Proposal in this manner is consistent with the manner in which the Company proposes to offset the costs of the respective DGSC and RE Growth programs and maintains transparency with respect to the costs associated with each program.

Q. Has the Company considered other approaches to recovering the costs of its FCM Proposal from customers?

A. Yes. An alternative option is to recover the all of the costs of the FCM Proposal through a single existing or new reconciling mechanism. However, the Company believes that matching the net economic benefit of participating in the FCM with the costs of the projects that would generate the net benefits provides a clearer quantification of the respective program costs.

Q. What is the basis for the PUC to approve the Company's administrative cost-recovery mechanism in connection with the FCM Proposal?

A. With respect to projects under the RE Growth Program, R.I. Gen. Laws § 39-26.6-13 explicitly authorizes the recovery of incremental costs in order to meet the program objectives, subject to the PUC's review and approval that such costs were properly and prudently incurred. The Company currently recovers such administrative costs through the RE Growth Program Cost Recovery Provision. Although the Long-Term Contracting Standard, R.I. Gen. Laws §39-26.1 et seq., does not explicitly provide for similar recovery of incremental administrative costs associated with DGSC projects that were in effect prior to the implementation of the RE Growth Program, the statute also does not prohibit recovery of such costs. The PUC has broad regulatory authority to review and approve the recovery of costs that are prudently incurred for the purpose of setting just and reasonable rates. There is no substantive difference between the incremental administrative costs associated with bidding the DG Facilities in the FCM that are DGSC projects versus RE Growth Program projects. In each case, the PUC has the discretion to

determine whether such costs were prudently incurred. Therefore, the lack of a specific statutory provision authorizing recovery of administrative costs for DGSC projects, specifically, does not preclude approval of the mechanism to recover the incremental administrative costs associated with bidding the capacity of those projects into the FCM.

Q. What are the anticipated ISO-NE costs associated with the Company's participation in the FCM?

A. ISO-NE assesses a qualification fee on each project that is submitted for qualification in the FCM, which is referred to as the Qualification Process Cost Reimbursement Deposit and is currently set at $500 per project for generating facilities less than 2 MW. At this time, the only other potential ISO-NE costs the Company identified are the Performance Incentive penalties that were discussed earlier in our testimony. As such, the Company has only factored the Qualification Process Cost Reimbursement Deposit and potential Performance Incentive penalties into the analyses presented in Schedules NG-4, NG-5, NG-6, and NG-7. However, as stated earlier in this testimony, any ISO-NE cost,[28] fee, charge, or penalty, including the Performance Incentive penalties and the loss of a Qualification Process Cost Reimbursement Deposit, would be reflected in the monthly invoice issued to the Company by ISO-NE, and therefore reflected in the Net FCM Proceeds.

[28] For an example, without limitation, of other possible costs, see footnote 14 above.

IX. Sharing of Net FCM Proceeds

Q. Please describe the Company's sharing proposal in more detail.

A. The Company proposes a symmetrical sharing arrangement in which it will be authorized to retain 20 percent of the annual Net FCM Proceeds, as defined above. The Company would credit the remaining 80 percent Net FCM Proceeds as one component in the amount to be reflected in the RE Growth and DGSC Recovery and Reconciliation Factors, thereby reducing the overall cost of the DG programs to the Company's customers. In the event that the Net FCM Proceeds from the DG Facilities are negative, or a net cost, in a given year (which would occur in the unlikely event that Performance Incentive penalties outweigh gross revenue), the Company will share the same 20 percent of the net cost and the remaining 80 percent of the net cost, as well as the Company's administrative costs, would be recovered from customers through the RE Growth and DGSC Recovery and Reconciliation Factors.

Q. Why is it appropriate for the Company to enter into such a sharing arrangement with customers?

A. Sharing in the net proceeds and net costs would align the interests of the Company and its customers and incent the Company to maximize the value of its DG FCM bidding portfolio for the benefit of its customers. The PUC has found in other proceedings that the creation of such incentives is an effective way to create value for customers. For example, in Docket 4038, the PUC approved changes to the Company's Natural Gas

Portfolio Management Plan, whereby the Company is allowed to earn incentives through margin sharing for maximizing the value of their portfolio of gas supply assets.[29] Also, as discussed above, an additional benefit to customers of the sharing arrangement is that the Company will share 20 percent of any net annual FCM cost, thereby lowering customers' risk.

X. Proposed Tariff Revisions

Q. Please describe the tariff changes necessary to implement the Company's FCM Proposal.

A. The Company is proposing to modify the RE Growth Program Cost Recovery Provision, RIPUC No. 2153, the LTCRER Provision, RIPUC No. 2127, and the LTCRER Reconciliation Provision, RIPUC No. 2125, as shown in the Schedules NG-9, NG-10, and NG-11. Specifically, the tariffs have been revised to (1) include a definition of Customer Share of Net FCM Proceeds; (2) allow for the recovery of actual incremental administrative costs associated with bidding the capacity of eligible DG Facilities in the FCM, and (3) modify the formulas, as detailed in Schedules NG-9, NG-10, and NG-11, as necessary to implement the Company's FCM Proposal.

[29] See Report and Order 19627, Docket 4038 (April 24, 2009).

XI. Conclusion

Q. Does this conclude your testimony?

A. Yes, it does.

Schedule NG-1

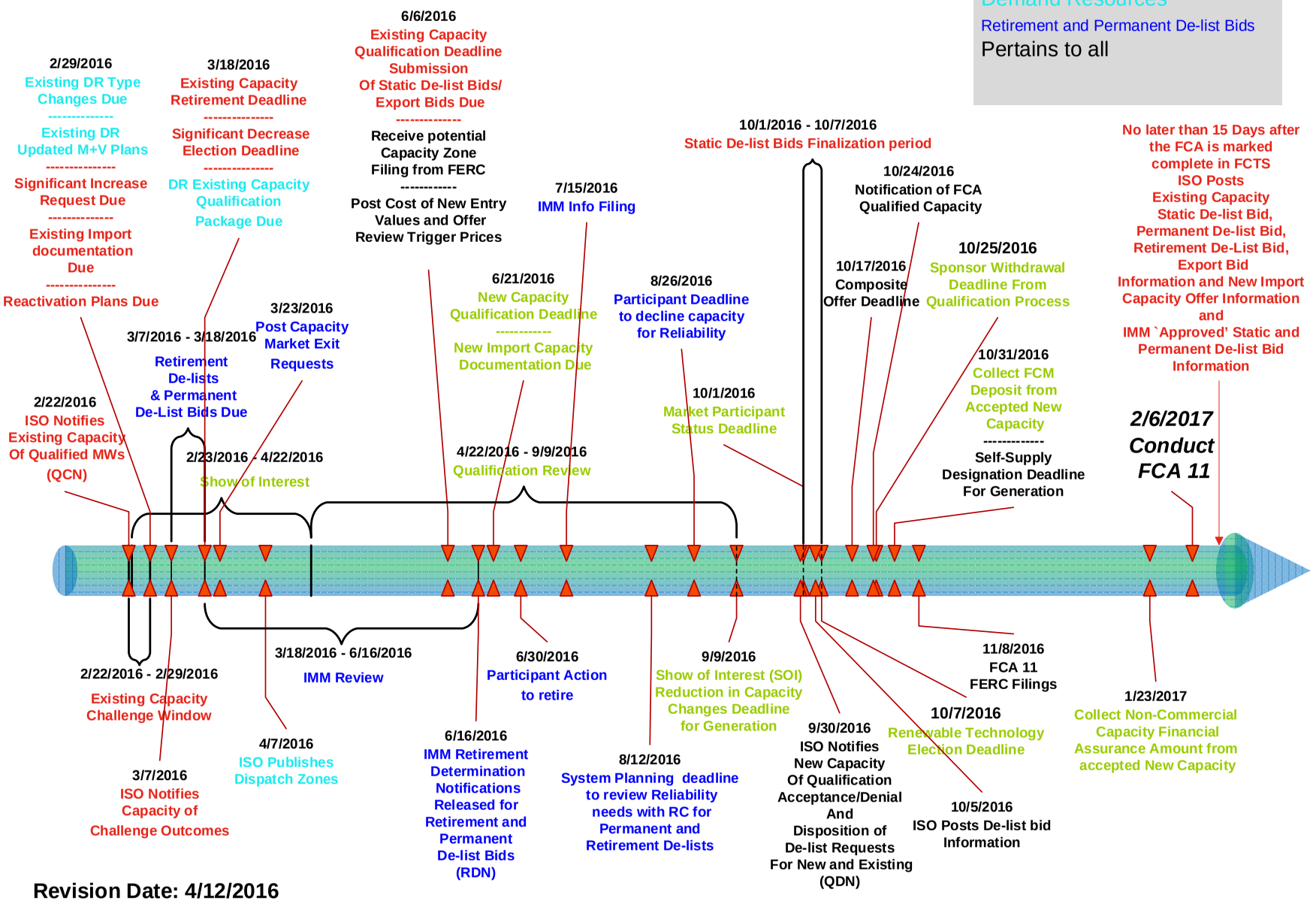
Schedule NG-1

Forward Capacity Auction 12 Timeline

Forward Capacity Auction #11 Schedule

Capacity Commitment Period: 2020-2021

Key:
Existing
New
Demand Resources
Retirement and Permanent De-list Bids
Pertains to all



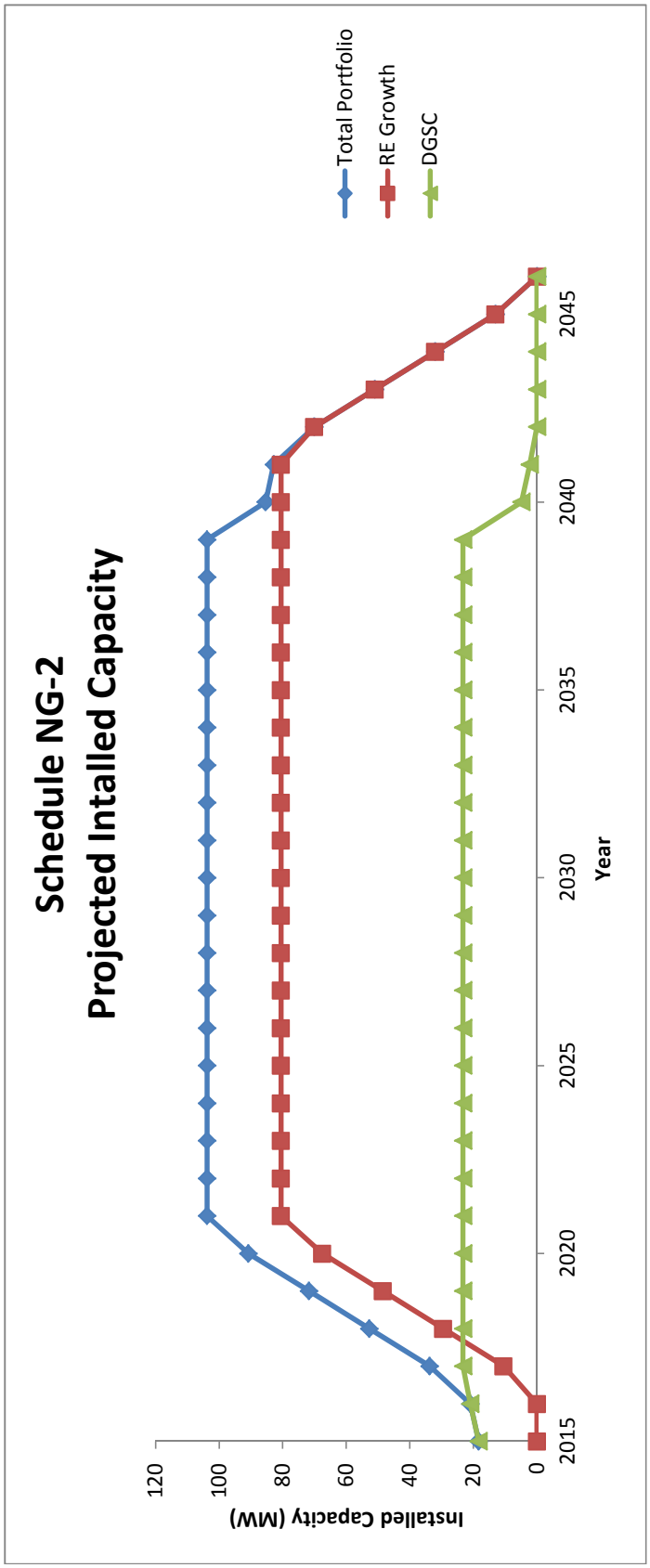
Revision Date: 4/12/2016

THE NARRAGANSETT ELECTRIC COMPANY
D/B/A NATIONAL GRID
RIPUC DOCKET NO. ____
PROPOSAL TO BID CAPACITY OF CUSTOMER-OWNED DG FACILITIES
INTO THE FORWARD CAPACITY MARKET
Schedule NG-1
Page 1 of 1

Schedule NG-2

Schedule NG-2

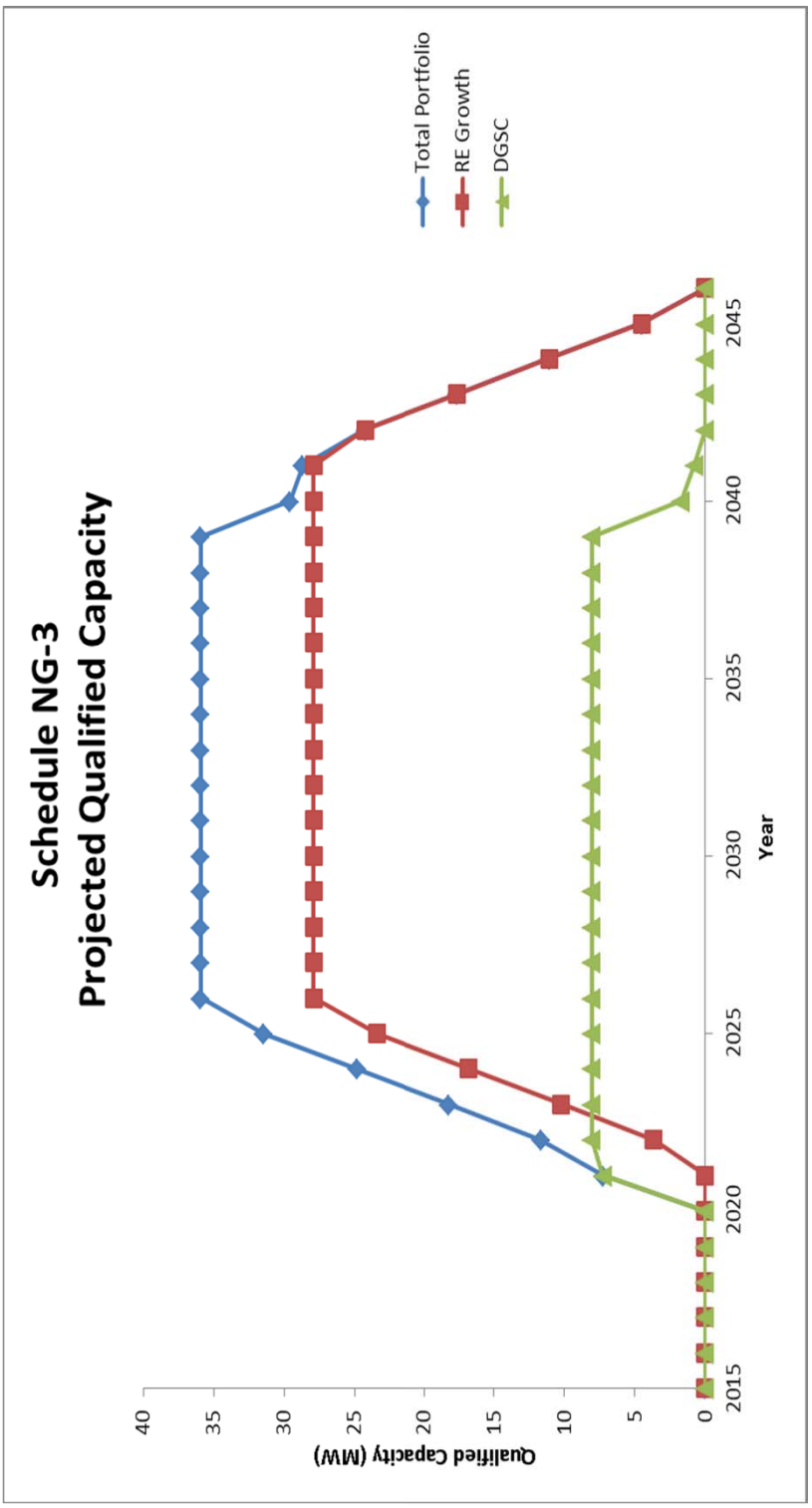
Projected Installed Capacity



*Projected Installed Capacity represents the AC nameplate capacity of the DG facilities in the Company's initial FCM portfolio that are larger than 250kW.

Schedule NG-3

Projected Qualified Capacity

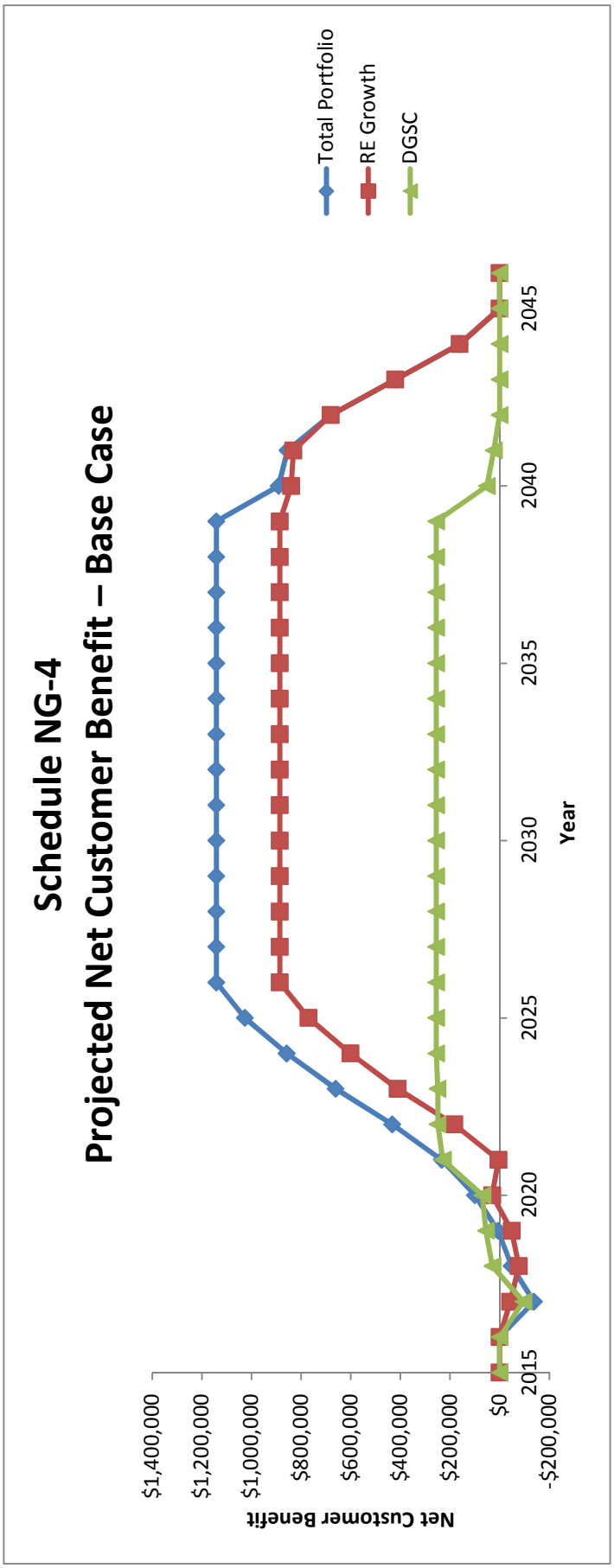


*Projected Qualified Capacity for solar facilities is based on the projected peak summer production and is assumed to be 35% of the installed nameplate capacity

Schedule NG-4

Schedule NG-4

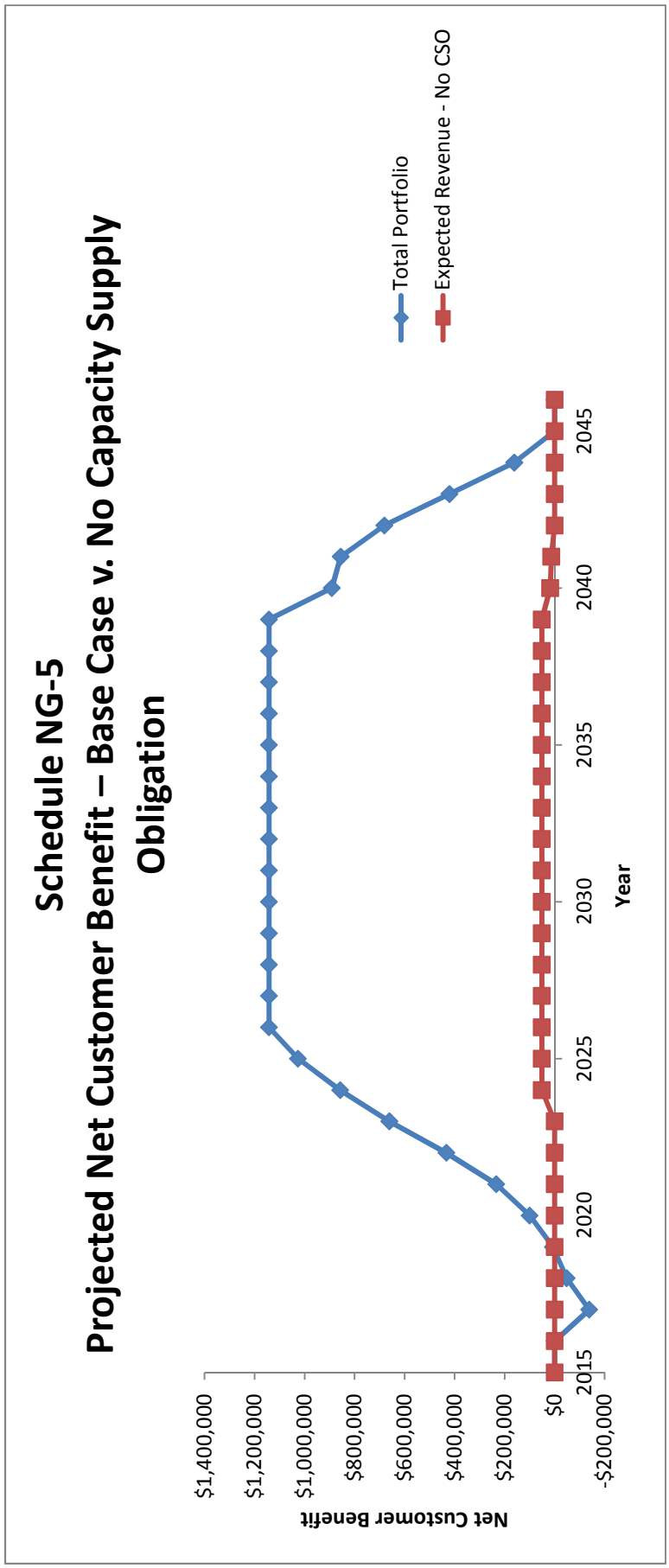
Projected Net Customer Benefit – Base Case


Schedule NG-4
Projected Net Customer Benefit – Base Case
Total Portfolio
RE Growth
DGSC
Net Customer Benefit
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
-$200,000
2015
2020
2025
2030
2035
2040
2045
Year

Schedule NG-5

Schedule NG-5

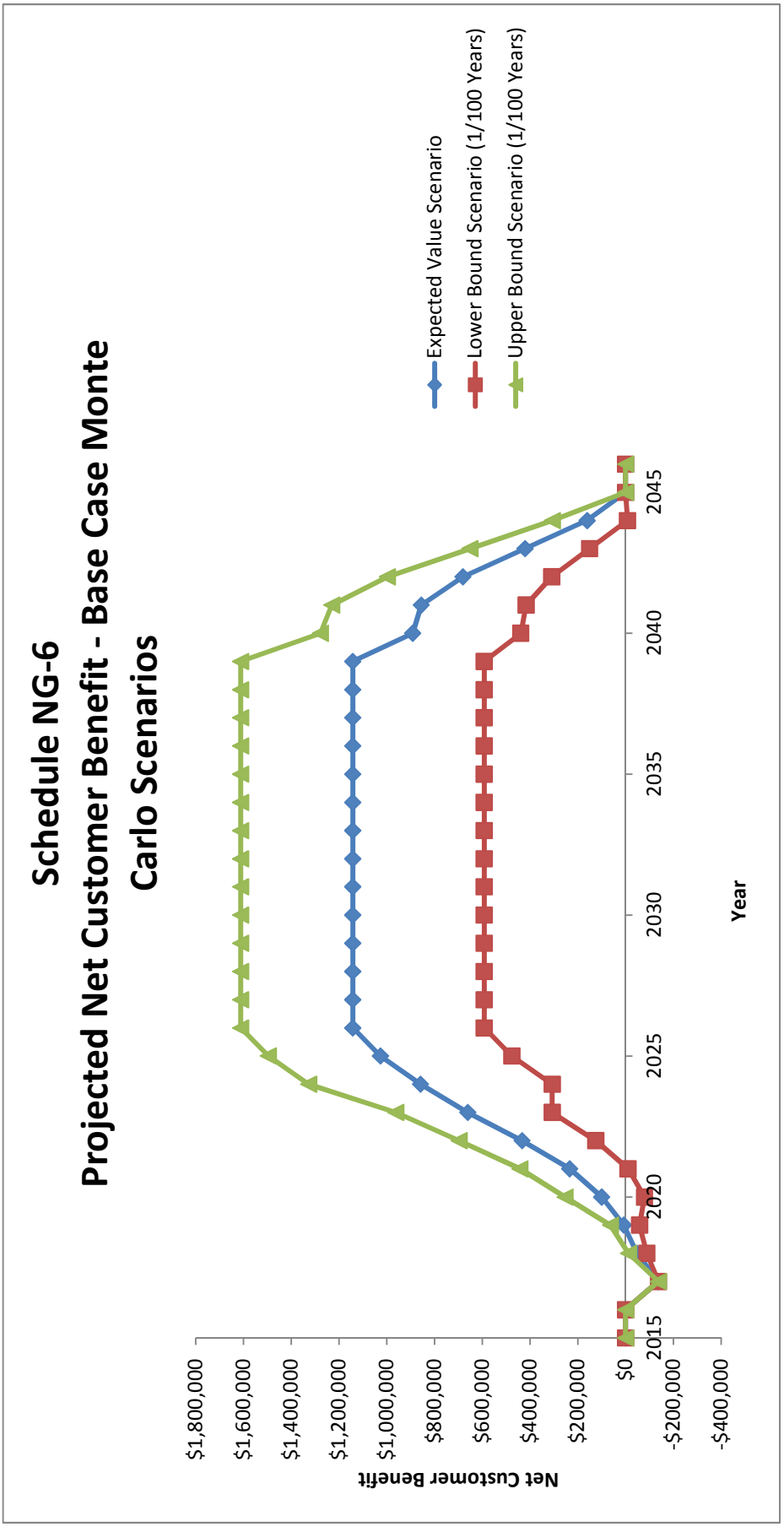
Projected Net Customer Benefit – Base Case v. No Capacity Supply Obligation


Schedule NG-5
Projected Net Customer Benefit – Base Case v. No Capacity Supply Obligation
Total Portfolio
Expected Revenue - No CSO
Net Customer Benefit
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
-$200,000
2015
2020
2025
2030
2035
2040
2045
Year

Schedule NG-6

Schedule NG-6

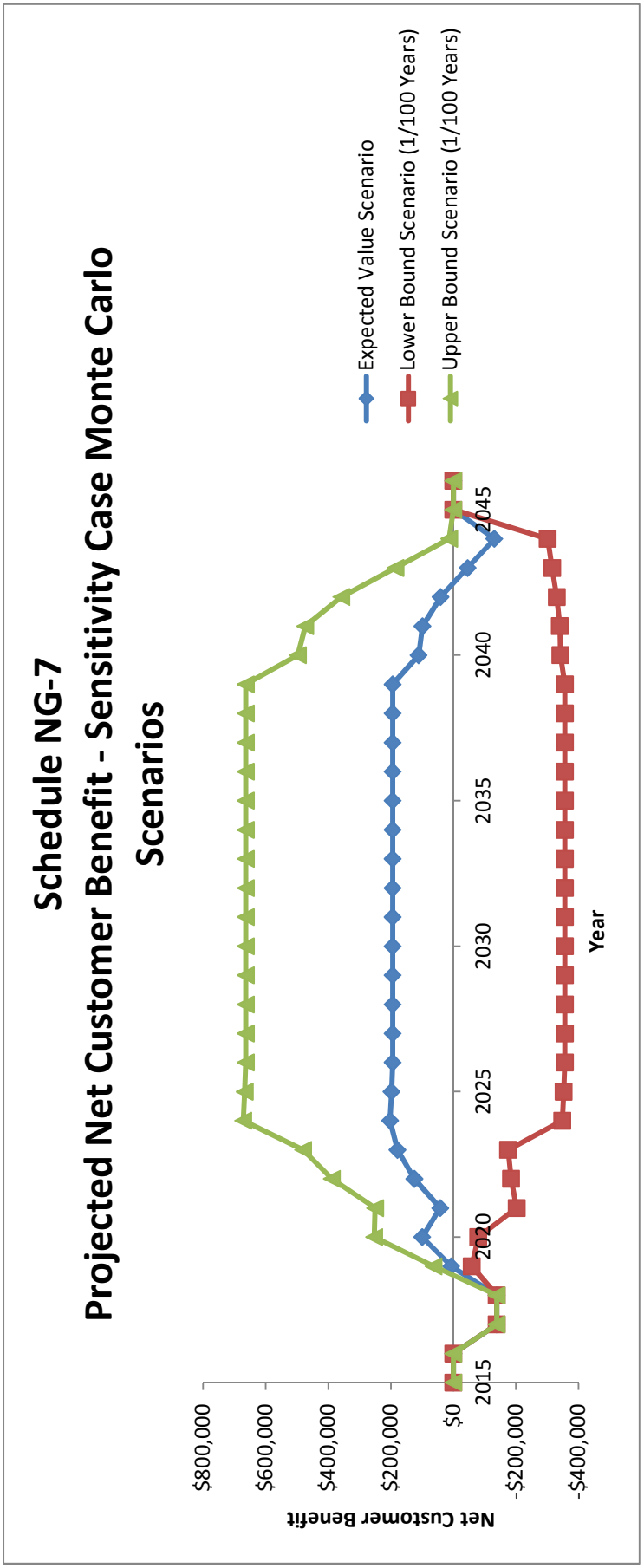
Projected Net Customer Benefit – Base Case Monte Carlo Scenarios


Schedule NG-6
Projected Net Customer Benefit - Base Case Monte Carlo Scenarios
Expected Value Scenario
Lower Bound Scenario (1/100 Years)
Upper Bound Scenario (1/100 Years)
Net Customer Benefit
$1,800,000
$1,600,000
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
-$200,000
-$400,000
2015
2020
2025
2030
2035
2040
2045
Year

Schedule NG-7

Schedule NG-7

Projected Net Customer Benefit – Sensitivity Case Monte Carlo Scenarios


Schedule NG-7
Projected Net Customer Benefit - Sensitivity Case Monte Carlo
Scenarios
Expected Value Scenario
Lower Bound Scenario (1/100 Years)
Upper Bound Scenario (1/100 Years)
Net Customer Benefit
$800,000
$600,000
$400,000
$200,000
$0
-$200,000
-$400,000
2015
2020
2025
2030
2035
2040
2045
Year

Schedule NG-8

Estimated Ongoing Administrative Costs

Schedule NG-8 - Estimated Ongoing Administrative Costs

Assumptions for Calculation of Administrative Costs	
Qualification Labor Hours (Hours/Project)	20
Monitoring Labor Hours (Annual Hours/Project)	30
Annual Administrative Cost per Fully-Burdened FTE ($/FTE)	$138,390

Case 1* - Median Project Size / Min Project Size = 250 kW

Assumed Average Project Size (MW)	
Commercial Scale (251-999 kW)	0.625
Large Scale (1,000 - 5,000 kW)	2.5

Year	Incremental Projects	Cumulative Projects	Qualification Labor Hours	Monitoring Labor Hours	Total Labor Hours	Annual FTE Labor Hours	Estimated Number FTEs	Annual Administrative Cost
2017	33	33	652	978	1630	1960	1	$138,390
2018	17	50	344	1494	1838	1960	1	$138,390
2019	17	67	344	2010	2354	1960	1	$138,390
2020	17	84	344	2526	2870	1960	1	$138,390
2021	12	96	236	2880	3115	1960	2	$276,780

*Note that the administrative costs in Case 1 are used in the estimates of the Net Customer Benefit

Case 2 - Small Project Size / Min Project Size = 250 kW

Assumed Average Project Size (MW)	
Commercial Scale (251-999 kW)	0.251
Large Scale (1,000 - 5,000 kW)	1

Year	Incremental Projects	Cumulative Projects	Qualification Labor Hours	Monitoring Labor Hours	Total Labor Hours	Annual FTE Labor Hours	Estimated Number FTEs	Annual Administrative Cost
2017	47	47	939	1408	2346	1960	1	$138,390
2018	43	90	857	2694	3551	1960	2	$276,780
2019	43	133	857	3980	4838	1960	2	$276,780
2020	43	176	857	5266	6124	1960	3	$415,170
2021	29	205	588	6148	6735	1960	3	$415,170

Case 3 - Median Project Size / Min Project Size = 25 kW

Assumed Average Project Size (MW)	
Medium Scale (25-250 kW)	0.15
Commercial Scale (251-999 kW)	0.625
Large Scale (1,000 - 5,000 kW)	2.5

Year	Incremental Projects	Cumulative Projects	Qualification Labor Hours	Monitoring Labor Hours	Total Labor Hours	Annual FTE Labor Hours	Estimated Number FTEs	Annual Administrative Cost
2017	59	59	1185	1778	2963	1960	2	$276,780
2018	51	110	1011	3294	4305	1960	2	$276,780
2019	51	160	1011	4810	5821	1960	3	$415,170
2020	51	211	1011	6326	7337	1960	4	$553,560
2021	35	245	693	7365	8058	1960	4	$553,560

Schedule NG-9

Schedule NG-9

Proposed Renewable Energy Growth Cost Recovery Provision

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

1. INTRODUCTION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect the recovery of costs incurred in accordance with the provisions of Rhode Island General Laws Chapter 39-26.6, the Renewable Energy Growth Program ("RE Growth Program"), and its tariffs (collectively, "RE Growth Tariffs").

2. DEFINITIONS

Commission shall mean the Rhode Island Public Utilities Commission.

Company shall mean The Narragansett Electric Company d/b/a National Grid.

Distributed Generation Facility shall mean an electrical generation facility located in the Company's service territory with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by R.I. Gen. Laws § 39-26-5, including biogas created as a result of anaerobic digestion, but specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Market Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Distributed Generation Facility.

Performance-Based Incentive shall mean the price per kilowatt-hour ("kWh") applicable to Distributed Generation Facilities participating in the RE Growth Program pursuant to the RE Growth Tariffs.

Performance-Based Incentive Payment shall mean the compensation paid to eligible Distributed Generation Facilities pursuant to the RE Growth Tariffs.

Performance Guarantee Deposit shall mean a deposit as required pursuant to the Renewable Energy Growth Program for Non-Residential Customers tariff.

Program Year shall mean a year beginning April 1 and ending March 31, unless otherwise approved by the Commission.

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

Rate Base Allocator shall mean the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study. The Rate Base Allocator shall be as follows by rate class:

Rate Class	Percentage
A-16/A-60	52.78%
C-06	9.71%
G-02	14.68%
B/G-32	13.82%
B/G-62/X-01	3.79%
Streetlighting	5.21%

Reconciliation Period shall mean the most recent twelve-month period ending March 31.

Remuneration shall mean the annual compensation as authorized by R.I. Gen. Laws § 39-26.6-12(j)(3), which shall be equal to one and three-quarters percent (1.75%) of the annual Performance-Based Incentive Payments provided during the Reconciliation Period.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in R.I. Gen. Laws § 39-26-2(15).

Short Term Interest Rate shall mean the interest rate applicable to borrowers from the National Grid USA Money Pool.

3. APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of the Rhode Island General Laws:

i) § 39-26.6-4: Covers the cost of qualified consultants hired to perform reports or studies applicable to the RE Growth Program;

ii) § 39-26.6-12: Covers annual remuneration;

iii) § 39-26.6-13: Covers cost reconciliation relating to incremental costs the Company incurs to meet program objectives. This provision also covers the costs the Company incurs to make billing system improvements to achieve the goals of the RE Growth Program;

iv) §39-26.6-18: Covers the installation and capital costs the Company incurs to install separate meters for small-scale solar projects; and

v) § 39-26.6-25: Covers the forecasted rate and reconciliation relating to the total amount of payments the Company is likely to pay out to distributed generation

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

projects in the upcoming program year.

4. RATE

The RE Growth Factor will be based upon the annual costs the Company estimates it will incur during the applicable 12-month period and will include an adjustment for uncollectible amounts at the Company's currently approved uncollectible percentage. The RE Growth Factor shall remain in effect until adjusted as a result of updated estimates of costs to be recovered over a 12-month period as included in the Company's annual reconciliation filing pursuant to Section 5 below. The Company may submit a request to the Commission to adjust the RE Growth Factor at any time should significant over or under recovery of costs occur.

The RE Growth Factor shall be applicable to all retail delivery service customers and will be in the form of a monthly fixed charge. The RE Growth Factor will be calculated as follows:

$$\text{RE Growth Factor}_{sx} = [(PBIP_x - PRDCTS_x - NFCMP_x + ADM_x) \times RBA_s) \div FBill_{sx}] \div (1 - UP)$$

where

x	=	the Reconciliation Period;
s	=	designates a separate factor for each rate class;
$PBIP_x$	=	the estimated Performance-Based Incentive Payments, consisting of direct payments to recipients and credits on customer bills, that the Company expects to make under the RE Growth Tariffs for period x during which the RE Growth Factor will be in effect;
$PRDCTS_x$	=	the expected net proceeds for period x during which the RE Growth Factor will be in effect and which the Company will receive as a result of the sale of the Market Products;
$NFCMP_x$	=	the estimated Customer Share of Net Forward Capacity Market Proceeds during period x;
ADM_x	=	the administrative expense the Company estimates it will incur during period x, including:

1) the Remuneration pursuant to Section 3.ii) above;

2) the estimated revenue requirement associated with the incremental investment in meters installed on small scale solar Distributed Generation Facilities pursuant to Section 3.iv) above;

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

3) all incremental costs necessary to meet program objectives or make billing system improvements to implement RE Growth Program pursuant to Section 3.iii) above;

4) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i) above; and

5) the estimated incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

RBA_s = Rate Base Allocator;

$FBill_{sx}$ = the forecasted number of electric service bills for each rate class for period x; and

UP = the uncollectible percentage approved by the Commission in the Company's most recent rate case.

5. RECONCILIATION FACTOR

On an annual basis and within three months after the end of a Program Year, the Company shall file a reconciliation of the revenue billed through RE Growth Factor, excluding the adjustment for uncollectible amounts, to the actual expenses incurred during the Reconciliation Period, and the excess or deficiency, including interest at the Company's Short Term Interest Rate, shall be refunded to, or recovered from, all customers through a RE Growth Reconciliation Factor. For billing purposes, the RE Growth Reconciliation Factor will be included with the RE Growth Factor on a single line item on customers' bills.

The RE Growth Reconciliation Factor shall be calculated separately for each rate class as follows:

$$\text{RE Growth Reconciliation Factor}_{sx} = [((PPRA_{x-1} + I_x) \times RBA_s) \div FBill_{sx}] \div (1 - UP)$$

where

x = the period during which the RE Growth Reconciliation Factor will be in effect;

s = designates a separate factor for each rate class;

$PPRA_{x-1}$ = the past period reconciliation amount to be recovered through the RE Growth Reconciliation Factor during period x, defined as the ending balance of the difference between:

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 5

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

(a) actual costs incurred during the Reconciliation Period, which shall include the sum of:

1) actual Performance-Based Incentive Payments made during the Reconciliation Period pursuant to the RE Growth Tariffs less actual proceeds received by the Company resulting from the sale of the Market Products;

2) actual Customer Share of Net Forward Capacity Market Proceeds;

3) the Remuneration pursuant to Section 3.ii);

4) the revenue requirement associated with the incremental investment in meters installed on small scale solar Distributed Generation Facilities per Section 3.iv);

5) all incremental costs necessary to meet program objectives or make billing system improvements to implement RE Growth Program pursuant Section 3.iii);

6) actual incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

7) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i); and

8) a credit for any forfeited Performance Guarantee Deposits during the Reconciliation Period which is reflected as an offset to expense;

and

(b) revenue billed through the RE Growth Factor as approved by the Commission for the Reconciliation Period;

RBA_s = Rate Base Allocator;

I_x = interest calculated as the sum of the beginning period and ending period reconciliation balance divided by 2, multiplied by the Company's Short Term Interest Rate during the Reconciliation Period;

$FBill_{sx}$ = the forecasted number of electric service bills for each rate class for period x; and

CLEAN VERSION

RIPUC No. 2176
Cancelling R.I.P.U.C. No 2153
Sheet 6

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

UP	=	the uncollectible percentage approved by the Commission in the Company's most recent rate case.

6. ADJUSTMENTS TO RATES

Adjustments to the RE Growth Factor and RE Growth Reconciliation Factor in accordance with this RE Growth Cost Recovery Provision are subject to review and approval by the Commission. The Company shall file the initial RE Growth Factor on or before January 1, 2015. The Company shall file revisions to the RE Growth Factor and the RE Growth Reconciliation Factor within three months following the end of the Program Year. Modifications to the factors contained in this Renewable Energy Growth Program Cost Recovery Provision shall be in accordance with a notice filed with the Commission pursuant to R.I. Gen. Laws § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such changes.

Effective Date: January 1, 2017

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

1. INTRODUCTION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect the recovery of costs incurred in accordance with the provisions of Rhode Island General Laws Chapter 39-26.6, the Renewable Energy Growth Program ("RE Growth Program"), and its tariffs (collectively, "RE Growth Tariffs").

2. DEFINITIONS

Commission shall mean the Rhode Island Public Utilities Commission.

Company shall mean The Narragansett Electric Company d/b/a National Grid.

Distributed Generation Facility shall mean an electrical generation facility located in the Company's service territory with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by R.I. Gen. Laws § 39-26-5, including biogas created as a result of anaerobic digestion, but specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Market Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Distributed Generation Facility.

Performance-Based Incentive shall mean the price per kilowatt-hour ("kWh") applicable to Distributed Generation Facilities participating in the RE Growth Program pursuant to the RE Growth Tariffs.

Performance-Based Incentive Payment shall mean the compensation paid to eligible Distributed Generation Facilities pursuant to the RE Growth Tariffs.

Performance Guarantee Deposit shall mean a deposit as required pursuant to the Renewable Energy Growth Program for Non-Residential Customers tariff.

Program Year shall mean a year beginning April 1 and ending March 31, unless otherwise approved by the Commission.

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

Rate Base Allocator shall mean the percentage of total rate base allocated to each rate class taken from the most recent proceeding before the Commission that contained an allocated cost of service study. The Rate Base Allocator shall be as follows by rate class:

Rate Class	Percentage
A-16/A-60	52.78%
C-06	9.71%
G-02	14.68%
B/G-32	13.82%
B/G-62/X-01	3.79%
Streetlighting	5.21%

Reconciliation Period shall mean the most recent twelve-month period ending March 31.

Remuneration shall mean the annual compensation as authorized by R.I. Gen. Laws § 39-26.6-12(j)(3), which shall be equal to one and three-quarters percent (1.75%) of the annual Performance-Based Incentive Payments provided during the Reconciliation Period.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in R.I. Gen. Laws § 39-26-2(15).

Short Term Interest Rate shall mean the interest rate applicable to borrowers from the National Grid USA Money Pool.

3. APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of the Rhode Island General Laws:

i) § 39-26.6-4: Covers the cost of qualified consultants hired to perform reports or studies applicable to the RE Growth Program;

ii) § 39-26.6-12: Covers annual remuneration;

iii) § 39-26.6-13: Covers cost reconciliation relating to incremental costs the Company incurs to meet program objectives. This provision also covers the costs the Company incurs to make billing system improvements to achieve the goals of the RE Growth Program;

iv) §39-26.6-18: Covers the installation and capital costs the Company incurs to install separate meters for small-scale solar projects; and

v) § 39-26.6-25: Covers the forecasted rate and reconciliation relating to the total amount of payments the Company is likely to pay out to distributed generation

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

projects in the upcoming program year.

4. RATE

The RE Growth Factor will be based upon the annual costs the Company estimates it will incur during the applicable 12-month period and will include an adjustment for uncollectible amounts at the Company's currently approved uncollectible percentage. The RE Growth Factor shall remain in effect until adjusted as a result of updated estimates of costs to be recovered over a 12-month period as included in the Company's annual reconciliation filing pursuant to Section 5 below. The Company may submit a request to the Commission to adjust the RE Growth Factor at any time should significant over or under recovery of costs occur.

The RE Growth Factor shall be applicable to all retail delivery service customers and will be in the form of a monthly fixed charge. The RE Growth Factor will be calculated as follows:

$$\text{RE Growth Factor}_{sx} = [(PBIP_x - PRDCTS_x - NFCMP_x + ADM_x) \times RBA_s) \div FBill_{sx}] \div (1 - UP)$$

where

x	=	the Reconciliation Period;
s	=	designates a separate factor for each rate class;
$PBIP_x$	=	the estimated Performance-Based Incentive Payments, consisting of direct payments to recipients and credits on customer bills, that the Company expects to make under the RE Growth Tariffs for period x during which the RE Growth Factor will be in effect;
$PRDCTS_x$	=	the expected net proceeds for period x during which the RE Growth Factor will be in effect and which the Company will receive as a result of the sale of the Market Products;
$NFCMP_x$	=	the estimated Customer Share of Net Forward Capacity Market Proceeds during period x;
ADM_x	=	the administrative expense the Company estimates it will incur during period x, including:

1) the Remuneration pursuant to Section 3.ii) above;

2) the estimated revenue requirement associated with the incremental investment in meters installed on small scale solar Distributed Generation Facilities pursuant to Section 3.iv) above;

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

3) all incremental costs necessary to meet program objectives or make billing system improvements to implement RE Growth Program pursuant to Section 3.iii) above; ~~and~~

4) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i) above; and

~~4)~~5) the estimated incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

RBA_s = Rate Base Allocator;

$FBill_{sx}$ = the forecasted number of electric service bills for each rate class for period x; and

UP = the uncollectible percentage approved by the Commission in the Company's most recent rate case.

5. RECONCILIATION FACTOR

On an annual basis and within three months after the end of a Program Year, the Company shall file a reconciliation of the revenue billed through RE Growth Factor, excluding the adjustment for uncollectible amounts, to the actual expenses incurred during the Reconciliation Period, and the excess or deficiency, including interest at the Company's Short Term Interest Rate, shall be refunded to, or recovered from, all customers through a RE Growth Reconciliation Factor. For billing purposes, the RE Growth Reconciliation Factor will be included with the RE Growth Factor on a single line item on customers' bills.

The RE Growth Reconciliation Factor shall be calculated separately for each rate class as follows:

$$\text{RE Growth Reconciliation Factor}_{sx} = [((PPRA_{x-1} + I_x) \times RBA_s) \div FBill_{sx}] \div (1 - UP)$$

where

x = the period during which the RE Growth Reconciliation Factor will be in effect;

s = designates a separate factor for each rate class;

$PPRA_{x-1}$ = the past period reconciliation amount to be recovered through the RE Growth Reconciliation Factor during period x, defined as the ending balance of the difference between:

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 5

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

(a) actual costs incurred during the Reconciliation Period, which shall include the sum of:

1) actual Performance-Based Incentive Payments made during the Reconciliation Period pursuant to the RE Growth Tariffs less actual proceeds received by the Company resulting from the sale of the Market Products;

~~1)~~2) actual Customer Share of Net Forward Capacity Market Proceeds;

~~2)~~3) the Remuneration pursuant to Section 3.ii);

~~3)~~4) the revenue requirement associated with the incremental investment in meters installed on small scale solar Distributed Generation Facilities per Section 3.iv);

5) all incremental costs necessary to meet program objectives or make billing system improvements to implement RE Growth Program pursuant Section 3.iii);

6) actual incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

~~4)~~7) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i); and

~~5)~~8) a credit for any forfeited Performance Guarantee Deposits during the Reconciliation Period which is reflected as an offset to expense;

and

(b) revenue billed through the RE Growth Factor as approved by the Commission for the Reconciliation Period;

RBA_s = Rate Base Allocator;

I_x = interest calculated as the sum of the beginning period and ending period reconciliation balance divided by 2, multiplied by the Company's Short Term Interest Rate during the Reconciliation Period;

$FBill_{sx}$ = the forecasted number of electric service bills for each rate class for period x; and

REDLINED VERSION

RIPUC No. ~~2153~~2176
Cancelling R.I.P.U.C. No 2153
Sheet 6

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

UP	=	the uncollectible percentage approved by the Commission in the Company's most recent rate case.

6. ADJUSTMENTS TO RATES

Adjustments to the RE Growth Factor and RE Growth Reconciliation Factor in accordance with this RE Growth Cost Recovery Provision are subject to review and approval by the Commission. The Company shall file the initial RE Growth Factor on or before January 1, 2015. The Company shall file revisions to the RE Growth Factor and the RE Growth Reconciliation Factor within three months following the end of the Program Year. Modifications to the factors contained in this Renewable Energy Growth Program Cost Recovery Provision shall be in accordance with a notice filed with the Commission pursuant to R.I. Gen. Laws § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such changes.

Effective Date: January 1, 2017~~April 1, 2015~~

Schedule NG-10

Schedule NG-10

Proposed Long Term Contracting for Renewable Energy Recovery Provision

CLEAN VERSION

R.I.P.U.C. No. 2174
Cancelling R.I.P.U.C. No 2127
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect recovery of costs incurred in accordance with the provisions of Chapter 39-26.1, Long-Term Contracting Standard for Renewable Energy and Chapter 39-26.2, Distributed Generation Standard Contracts.

1) DEFINITIONS

Contract Remuneration shall mean the annual compensation as authorized by § 39-26.1-4, which shall be equal to two and three quarter percent (2.75%) of the actual annual payments made under the Long Term Contracts and Distributed Generation Standard Contracts for those projects that are commercially operating.

Contract Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Newly Developed Renewable Energy Resource, or a Distributed Generation Facility, which are purchased by the Company pursuant to a Long-term Contract or a Distributed Generation Standard Contract.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Distributed Generation Facility shall mean an electrical generation facility that is a newly developed renewable energy resource as defined in § 39-26.1-2, located in the Company's load zone with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by § 39-26-5, including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Distributed Generation Standard Contract shall mean a contract with a term of fifteen (15) years at a fixed rate for the purchase of all Contract Products generated by a Distribution Generation Facility, which is executed with the Company pursuant to R.I.G.L. 39-26.2.

Forecasted kWh shall mean the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.

Long-term Contract shall mean a contract of not less than ten (10) years, for the purchase of Contract Products, which is executed with the Company pursuant to R.I.G.L. 39-26.1.

Newly Developed Renewable Energy Resource shall have the meaning set forth in §39-26.1-2(6).

CLEAN VERSION

R.I.P.U.C. No. 2174
Cancelling R.I.P.U.C. No 2127
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

Performance Guarantee Deposit shall mean a deposit as required pursuant to § 39-26.2-7(2)(ii) paid to the Company of fifteen dollars ($15.00) for a small Distributed Generation Facility or twenty-five dollars ($25.00) for a large Distributed Generation Facility for every Renewable Energy Certificate estimated to be generated per year under the Distributed Generation Standard Contract, but at least five hundred dollars ($500) and not more than seventy-five thousand dollar ($75,000) paid at the time of contract execution.

Reimbursement Agreement shall mean a cost reimbursement agreement entered into between the Company and a lawyer designated by the Office of Energy Resources ("OER") that is intended to compensate such lawyer for the time spent serving in the contract working group established pursuant to the provisions of § 39-26.2-7(1) at a reasonable hourly rate negotiated by OER.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in § 39-26-2(15).

Town of New Shoreham Project shall mean a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland as provided for in § 39-26.1-7.

Town of Johnston Project shall mean a newly developed renewable energy resource fueled by landfill gas from the central landfill in the Town of Johnston as provided for in § 39-26.1-9.

2) APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of Rhode Island General Law:

i) § 39-26.1-4: Financial remuneration and incentives;

ii) § 39-26.1-5: Commission approval and regulations, subsection (f)

iii) § 39-26.1-7: the Town of New Shoreham Project, subsection (d);

iv) § 39-26.1-9: the Town of Johnston Project, subsection (8);

v) § 39-26.2-6: Standard contract enrollment program, subsection (f);

vi) § 39-26.2-7: Standard contract – Form and provisions, subsections (1)(vi), (2)(i), (2)(iv) and (3);

3) RATE

CLEAN VERSION

R.I.P.U.C. No. 2174
Cancelling R.I.P.U.C. No 2127
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY RECOVERY PROVISION

The Long-term Contracting for Renewable Energy Recovery ("LTCRER") factor shall be established semi-annually based upon the costs expected to be incurred during the subsequent six-month period including an adjustment for uncollectible amounts at the Company's currently approved uncollectible allowance rate.

The LTCRER factor shall be a uniform per kilowatt-hour factor applicable to all customers based on the Forecasted kWhs during the six month period that the LTCRER factor will be in effect. For billing purposes, the LTCRER factor will be included with the Renewable Energy Distribution kWh charge on customers' bills.

The LTCRER factor will be calculated as follows:

$$\text{LTCRER Factor}_X = \{[(AM_x - NFCMP_x + ADM_x) \div FkWh_x]\} \times (1 + UP)$$

where

x	=	The six-month period during which the annual LTCRER will be in effect;
LTCRER Factor_x	=	The Long-term Contracting Renewable Energy Recovery Factor for the current six-month period;
AM_x	=	The estimated annual above-market cost associated with Long-term Contracts and Distributed Generation Standard Contracts, calculated as the sum of the estimated payments expected to be made during period x under each of the approved Contracts less the expected proceeds to be received during period x by the Company resulting from the sale of the Contract Products;
$NFCMP_x$	=	The estimated Customer Share of Net Forward Capacity Market Proceeds during period x;
ADM_x	=	The estimated incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;
$FkWh_x$	=	The Forecasted kWh for the six-month period following the effective date of the LTCRER; and
UP	=	The uncollectible percentage approved by the Commission in the Company's most recent rate case.

CLEAN VERSION

R.I.P.U.C. No. 2174
Cancelling R.I.P.U.C. No 2127
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

4) ADJUSTMENTS TO RATES

Adjustments to rates pursuant to the LTCRER Provision are subject to review and approval by the Commission. The Company shall file its revised LTCRER factor semi-annually at least forty-five (45) days prior to the effective date of the revised LTCRER factor. Modifications to the factors contained in this LTCRER Provision shall be in accordance with a notice filed with the Commission pursuant to R.I.G.L. § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

Effective Date: January 1, 2017

REDLINED VERSION

R.I.P.U.C. No. ~~2127~~2174
Cancelling R.I.P.U.C No ~~2081~~2127
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect recovery of costs incurred in accordance with the provisions of Chapter 39-26.1, Long-Term Contracting Standard for Renewable Energy and Chapter 39-26.2, Distributed Generation Standard Contracts.

1) DEFINITIONS

Contract Remuneration shall mean the annual compensation as authorized by § 39-26.1-4, which shall be equal to two and three quarter percent (2.75%) of the actual annual payments made under the Long Term Contracts and Distributed Generation Standard Contracts for those projects that are commercially operating.

Contract Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Newly Developed Renewable Energy Resource, or a Distributed Generation Facility, which are purchased by the Company pursuant to a Long-term Contract or a Distributed Generation Standard Contract.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Distributed Generation Facility shall mean an electrical generation facility that is a newly developed renewable energy resource as defined in § 39-26.1-2, located in the Company's load zone with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by § 39-26-5, including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Distributed Generation Standard Contract shall mean a contract with a term of fifteen (15) years at a fixed rate for the purchase of all Contract Products generated by a Distribution Generation Facility, which is executed with the Company pursuant to R.I.G.L. 39-26.2.

Forecasted kWh shall mean the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.

Long-term Contract shall mean a contract of not less than ten (10) years, for the purchase of Contract Products, which is executed with the Company pursuant to R.I.G.L. 39-26.1.

Newly Developed Renewable Energy Resource shall have the meaning set forth in §39-26.1-2(6).

REDLINED VERSION

R.I.P.U.C. No. ~~2127~~2174
Cancelling R.I.P.U.C No ~~2081~~2127
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

Performance Guarantee Deposit shall mean a deposit as required pursuant to § 39-26.2-7(2)(ii) paid to the Company of fifteen dollars ($15.00) for a small Distributed Generation Facility or twenty-five dollars ($25.00) for a large Distributed Generation Facility for every Renewable Energy Certificate estimated to be generated per year under the Distributed Generation Standard Contract, but at least five hundred dollars ($500) and not more than seventy-five thousand dollar ($75,000) paid at the time of contract execution.

Reimbursement Agreement shall mean a cost reimbursement agreement entered into between the Company and a lawyer designated by the Office of Energy Resources ("OER") that is intended to compensate such lawyer for the time spent serving in the contract working group established pursuant to the provisions of § 39-26.2-7(1) at a reasonable hourly rate negotiated by OER.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in § 39-26-2(15).

Town of New Shoreham Project shall mean a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland as provided for in § 39-26.1-7.

Town of Johnston Project shall mean a newly developed renewable energy resource fueled by landfill gas from the central landfill in the Town of Johnston as provided for in § 39-26.1-9.

2) APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of Rhode Island General Law:

i) § 39-26.1-4: Financial remuneration and incentives;

ii) § 39-26.1-5: Commission approval and regulations, subsection (f)

iii) § 39-26.1-7: the Town of New Shoreham Project, subsection (d);

iv) § 39-26.1-9: the Town of Johnston Project, subsection (8);

v) § 39-26.2-6: Standard contract enrollment program, subsection (f);

vi) § 39-26.2-7: Standard contract – Form and provisions, subsections (1)(vi), (2)(i), (2)(iv) and (3);

3) RATE

REDLINED VERSION

R.I.P.U.C. No. ~~2127~~2174
Cancelling R.I.P.U.C No ~~2081~~2127
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

The Long-term Contracting for Renewable Energy Recovery ("LTCRER") factor shall be established semi-annually based upon the costs expected to be incurred during the subsequent six-month period including an adjustment for uncollectible amounts at the Company's currently approved uncollectible allowance rate.

The LTCRER factor shall be a uniform per kilowatt-hour factor applicable to all customers based on the Forecasted kWhs during the six month period that the LTCRER factor will be in effect. For billing purposes, the LTCRER factor will be included with the Renewable Energy Distribution kWh charge on customers' bills.

The LTCRER factor will be calculated as follows:

$$\text{LTCRER Factor}_X = \{[(AM_x - NFCMP_x + ADM_x) \div FkWh_x]\} \times (1 + UP)$$

where

x	=	The six-month period during which the annual LTCRER will be in effect;
LTCRER Factor_x	=	The Long-term Contracting Renewable Energy Recovery Factor for the current six-month period;
AM_x	=	The estimated annual above-market cost associated with Long-term Contracts and Distributed Generation Standard Contracts, calculated as the sum of the estimated payments expected to be made during period x under each of the approved Contracts less the expected proceeds to be received during period x by the Company resulting from the sale of the Contract Products;
$NFCMP_x$	=	The estimated Customer Share of Net Forward Capacity Market Proceeds during period x;
ADM_x	=	The estimated incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;
$FkWh_x$	=	The Forecasted kWh for the six-month period following the effective date of the LTCRER; and
UP	=	The uncollectible percentage approved by the Commission in the Company's most recent rate case.

REDLINED VERSION

R.I.P.U.C. No. ~~2127~~2174
Cancelling R.I.P.U.C. No ~~2081~~2127
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY PROVISION

4) ADJUSTMENTS TO RATES

Adjustments to rates pursuant to the LTCRER Provision are subject to review and approval by the Commission. The Company shall file its revised LTCRER factor semi-annually at least forty-five (45) days prior to the effective date of the revised LTCRER factor. Modifications to the factors contained in this LTCRER Provision shall be in accordance with a notice filed with the Commission pursuant to R.I.G.L. § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

Effective Date: January 1, 2017~~October 25, 2012~~

Schedule NG-11

Schedule NG-11

Proposed Long Term Contracting for Renewable Energy Recovery Reconciliation Provision

CLEAN VERSION

R.I.P.U.C. No. 2175
Cancelling R.I.P.U.C. No 2125
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect recovery of costs incurred in accordance with the provisions of Chapter 39-26.1, Long-Term Contracting Standard for Renewable Energy and Chapter 39-26.2, Distributed Generation Standard Contracts.

1) DEFINITIONS

Contract Remuneration shall mean the annual compensation as authorized by § 39-26.1-4, which shall be equal to two and three quarter percent (2.75%) of the actual annual payments made under the Long Term Contracts and Distributed Generation Standard Contracts for those projects that are commercially operating.

Contract Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Newly Developed Renewable Energy Resource, or a Distributed Generation Facility, which are purchased by the Company pursuant to a Long-term Contract or a Distributed Generation Standard Contract.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Distributed Generation Facility shall mean an electrical generation facility that is a newly developed renewable energy resource as defined in § 39-26.1-2, located in the Company's load zone with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by § 39-26-5, including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Distributed Generation Standard Contract shall mean a contract with a term of fifteen (15) years at a fixed rate for the purchase of all Contract Products generated by a Distribution Generation Facility, which is executed with the Company pursuant to R.I.G.L. 39-26.2.

Forecasted kWh shall mean the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.

Long-term Contract shall mean a contract of not less than ten (10) years, for the purchase of Contract Products, which is executed with the Company pursuant to R.I.G.L. 39-26.1.

Newly Developed Renewable Energy Resource shall have the meaning set forth in §39-26.1-2(6).

CLEAN VERSION

R.I.P.U.C. No. 2175
Cancelling R.I.P.U.C. No 2125
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

Performance Guarantee Deposit shall mean a deposit as required pursuant to § 39-26.2-7(2)(ii) paid to the Company of fifteen dollars ($15.00) for a small Distributed Generation Facility or twenty-five dollars ($25.00) for a large Distributed Generation Facility for every Renewable Energy Certificate estimated to be generated per year under the Distributed Generation Standard Contract, but at least five hundred dollars ($500) and not more than seventy-five thousand dollar ($75,000) paid at the time of contract execution.

Reconciliation Period shall mean the most recent twelve month period ending December 31.

Reimbursement Agreement shall mean a cost reimbursement agreement entered into between the Company and a lawyer designated by the Office of Energy Resources ("OER") that is intended to compensate such lawyer for the time spent serving in the contract working group established pursuant to the provisions of § 39-26.2-7(1) at a reasonable hourly rate negotiated by OER.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in § 39-26-2(15).

Town of New Shoreham Project shall mean a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland as provided for in § 39-26.1-7.

Town of Johnston Project shall mean a newly developed renewable energy resource fueled by landfill gas from the central landfill in the Town of Johnston as provided for in § 39-26.1-9.

2) APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of Rhode Island General Law:

i) § 39-26.1-4: Financial remuneration and incentives;

ii) § 39-26.1-5: Commission approval and regulations, subsection (f)

iii) § 39-26.1-7: the Town of New Shoreham Project, subsection (d);

iv) § 39-26.1-9: the Town of Johnston Project, subsection (8);

v) § 39-26.2-6: Standard contract enrollment program, subsection (f);

vi) § 39-26.2-7: Standard contract – Form and provisions, subsections (1)(vi), (2)(i),

CLEAN VERSION

R.I.P.U.C. No. 2175
Cancelling R.I.P.U.C. No 2125
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

(2)(iv) and (3);

3) RECONCILIATION FACTOR

On an annual basis, the Company shall reconcile the revenue billed through the Long-term Contracting for Renewable Recovery ("LTCRER") factor, as adjusted for uncollectible amounts at the Company's currently approved uncollectible allowance rate, to the actual expenses incurred, including the approved uncollectible allowance, during the Reconciliation Period, and the excess or deficiency, including interest at the Company's short term interest rate, shall be refunded to, or collected from, all customers in the two subsequent period's LTCRER factor. The Company may file to adjust the LTCRER Adjustment Factor at any time should significant over or under recovery of costs occur.

The LTCRER Reconciliation factor shall be a uniform per kilowatt-hour factor applicable to all customers based on the Forecasted kWhs during the twelve month period that the LTCRER Reconciliation factor will be in effect. For billing purposes, the LTCRER Reconciliation factor will be included with the Renewable Energy Distribution kWh charge on customers' bills.

The LTCRER Reconciliation factor will be calculated as follows:

LTCRER Reconciliation
$Factor_x$ = $[(PPRA_x + I_x) \div FkWh_x] \times (1 + UP)$

where

x = The twelve-month period during which the annual LTCRER Reconciliation factor will be in effect;

LTCRER Reconciliation
$Factor_x$ = The Long-term Contracting Renewable Energy Recovery Reconciliation Factor for the current twelve-month period;

$PPRA_x$ = The Past Period Reconciliation Amount to be collected through the LTCRER Reconciliation Factor during period x, defined as the ending balance of the difference between:

(a) the actual cost incurred during the Reconciliation Period, which shall include the sum of:

1) actual payments made during the Reconciliation Period under the individual approved Long-term Contracts and Distributed Generation Standard Contracts less (i) any proceeds received by the Company resulting from the

CLEAN VERSION

R.I.P.U.C. No. 2175
Cancelling R.I.P.U.C. No 2125
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

sale of the Contract Products and (ii) actual Customer Share of Net Forward Capacity Market Proceeds;

2) Contract Remuneration during the Reconciliation Period;

3) all costs incurred during the Reconciliation Period in the negotiation, administration, enforcement, and implementation of the projects and related agreements, and costs associated with the design of an undersea transmission cable interconnecting Block Island (Town of New Shoreham) to the mainland that are not otherwise recovered through the Transmission Service Cost Adjustment Provision pursuant to Sections 2.iii and 2.iv;

4) the costs incurred during the Reconciliation Period by the Company under Reimbursement Agreements pursuant to Section 2.vi;

5) the costs incurred during the Reconciliation Period associated with required system upgrades that are not recovered directly from Distributed Generation Facilities pursuant to Section 2.vii;

6) forfeited Performance Guarantee Deposits during the Reconciliation Period pursuant to Section 2.viii which shall be an offset to expense;

7) the costs incurred during the Reconciliation Period for consultants hired to assist the Commission in proceedings involving contract disputes pursuant to Section 2.ix; and

8) actual incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

and

(b) the revenues billed through the LTCRER Factors as approved by the Commission for the Reconciliation Period;

CLEAN VERSION

R.I.P.U.C. No. 2175
Cancelling R.I.P.U.C. No 2125
Sheet 5

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

I_x	=	interest calculated as the sum of the beginning period and ending period balance divided by 2, multiplied by the Company's short term interest rate during period x;
$FkWh_x$	=	The Forecasted kWh for the twelve month period following the effective date of the LTCRER Reconciliation factor; and
UP	=	The uncollectible percentage approved by the Commission in the Company's most recent rate case.

4) ADJUSTMENTS TO RATES

Adjustments to rates pursuant to the LTCRER Reconciliation Provision are subject to review and approval by the Commission. The Company shall file its revised LTCRER Reconciliation factor annually at least forty-five (45) days prior to the effective date of the revised LTCRER Reconciliation factor. Modifications to the factors contained in this LTCRER Reconciliation Provision shall be in accordance with a notice filed with the Commission pursuant to R.I.G.L. § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.

Effective Date: January 1, 2017

REDLINED VERSION

R.I.P.U.C. No. ~~2125~~2175
Cancelling R.I.P.U.C No ~~2081~~2125
Sheet 1

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

The Company's rates for Retail Delivery Service are subject to adjustment to reflect recovery of costs incurred in accordance with the provisions of Chapter 39-26.1, Long-Term Contracting Standard for Renewable Energy and Chapter 39-26.2, Distributed Generation Standard Contracts.

1) DEFINITIONS

Contract Remuneration shall mean the annual compensation as authorized by § 39-26.1-4, which shall be equal to two and three quarter percent (2.75%) of the actual annual payments made under the Long Term Contracts and Distributed Generation Standard Contracts for those projects that are commercially operating.

Contract Products shall mean the energy, capacity, Renewable Energy Certificates, or other attributes individually or any combination thereof, associated with the output from a Newly Developed Renewable Energy Resource, or a Distributed Generation Facility, which are purchased by the Company pursuant to a Long-term Contract or a Distributed Generation Standard Contract.

Customer Share of Net Forward Capacity Market Proceeds shall mean 80% of the proceeds received from or fees, charges, or penalties assessed by ISO-NE as a result of the Company's bidding the capacity of qualified customer-owned Distributed Generation Facilities into the ISO-NE Forward Capacity Market. These proceeds consist of all payments received from ISO-NE for participation in the Forward Capacity Market, less any ISO-NE fees, charges, or penalties that may be assessed pursuant to the Forward Capacity Market's rules.

Distributed Generation Facility shall mean an electrical generation facility that is a newly developed renewable energy resource as defined in § 39-26.1-2, located in the Company's load zone with a nameplate capacity no greater than five megawatts (5 MW), using eligible renewable energy resources as defined by § 39-26-5, including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels, and connected to an electrical power system owned, controlled, or operated by the Company.

Distributed Generation Standard Contract shall mean a contract with a term of fifteen (15) years at a fixed rate for the purchase of all Contract Products generated by a Distribution Generation Facility, which is executed with the Company pursuant to R.I.G.L. 39-26.2.

Forecasted kWh shall mean the forecasted amount of electricity to be delivered to the Company's retail delivery service customers.

Long-term Contract shall mean a contract of not less than ten (10) years, for the purchase of Contract Products, which is executed with the Company pursuant to R.I.G.L. 39-26.1.

Newly Developed Renewable Energy Resource shall have the meaning set forth in §39-26.1-2(6).

REDLINED VERSION

R.I.P.U.C. No. ~~2125~~2175
Cancelling R.I.P.U.C. No ~~2081~~2125
Sheet 2

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

Performance Guarantee Deposit shall mean a deposit as required pursuant to § 39-26.2-7(2)(ii) paid to the Company of fifteen dollars ($15.00) for a small Distributed Generation Facility or twenty-five dollars ($25.00) for a large Distributed Generation Facility for every Renewable Energy Certificate estimated to be generated per year under the Distributed Generation Standard Contract, but at least five hundred dollars ($500) and not more than seventy-five thousand dollar ($75,000) paid at the time of contract execution.

Reconciliation Period shall mean the most recent twelve month period ending December 31.

Reimbursement Agreement shall mean a cost reimbursement agreement entered into between the Company and a lawyer designated by the Office of Energy Resources ("OER") that is intended to compensate such lawyer for the time spent serving in the contract working group established pursuant to the provisions of § 39-26.2-7(1) at a reasonable hourly rate negotiated by OER.

Renewable Energy Certificate shall mean a New England Generation Information System renewable energy certificate as defined in § 39-26-2(15).

Town of New Shoreham Project shall mean a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the mainland as provided for in § 39-26.1-7.

Town of Johnston Project shall mean a newly developed renewable energy resource fueled by landfill gas from the central landfill in the Town of Johnston as provided for in § 39-26.1-9.

2) APPLICABILITY

Costs recovered under this provision are authorized for recovery pursuant to the following provisions of Rhode Island General Law:

i) § 39-26.1-4: Financial remuneration and incentives;

ii) § 39-26.1-5: Commission approval and regulations, subsection (f)

iii) § 39-26.1-7: the Town of New Shoreham Project, subsection (d);

iv) § 39-26.1-9: the Town of Johnston Project, subsection (8);

v) § 39-26.2-6: Standard contract enrollment program, subsection (f);

vi) § 39-26.2-7: Standard contract – Form and provisions, subsections (1)(vi), (2)(i),

REDLINED VERSION

R.I.P.U.C. No. ~~2125~~2175
Cancelling R.I.P.U.C No ~~2081~~2125
Sheet 3

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

(2)(iv) and (3);

3) RECONCILIATION FACTOR

On an annual basis, the Company shall reconcile the revenue billed through the Long-term Contracting for Renewable Recovery ("LTCRER") factor, as adjusted for uncollectible amounts at the Company's currently approved uncollectible allowance rate, to the actual expenses incurred, including the approved uncollectible allowance, during the Reconciliation Period, and the excess or deficiency, including interest at the Company's short term interest rate, shall be refunded to, or collected from, all customers in the two subsequent period's LTCRER factor. The Company may file to adjust the LTCRER Adjustment Factor at any time should significant over or under recovery of costs occur.

The LTCRER Reconciliation factor shall be a uniform per kilowatt-hour factor applicable to all customers based on the Forecasted kWhs during the twelve month period that the LTCRER Reconciliation factor will be in effect. For billing purposes, the LTCRER Reconciliation factor will be included with the Renewable Energy Distribution kWh charge on customers' bills.

The LTCRER Reconciliation factor will be calculated as follows:

LTCRER Reconciliation
$Factor_x$ = $[(PPRA_x + I_x ~~(i)~~) \div FkWh_x] \times (1 + UP)$

where

x = The twelve-month period during which the annual LTCRER Reconciliation factor will be in effect;

LTCRER Reconciliation
$Factor_x$ = The Long-term Contracting Renewable Energy Recovery Reconciliation Factor for the current twelve-month period;

$PPRA_x$ = The Past Period Reconciliation Amount to be collected through the LTCRER Reconciliation Factor during period x, defined as the ending balance of the difference between:

(a) the actual cost incurred during the Reconciliation Period, which shall include the sum of:

1) actual payments made during the Reconciliation Period under the individual approved Long-term Contracts and Distributed Generation Standard Contracts less (i) any proceeds received by the Company resulting from the

REDLINED VERSION

R.I.P.U.C. No. ~~2125~~2175
Cancelling R.I.P.U.C. No ~~2081~~2125
Sheet 4

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

sale of the Contract Products and (ii) actual Customer Share of Net Forward Capacity Market Proceeds;

~~1)~~2) Contract Remuneration during the Reconciliation Period;

~~2)~~3) all costs incurred during the Reconciliation Period in the negotiation, administration, enforcement, and implementation of the projects and related agreements, and costs associated with the design of an undersea transmission cable interconnecting Block Island (Town of New Shoreham) to the mainland that are not otherwise recovered through the Transmission Service Cost Adjustment Provision pursuant to Sections 2.iii and 2.iv;

~~3)~~4) the costs incurred during the Reconciliation Period by the Company under Reimbursement Agreements pursuant to Section 2.vi;

~~4)~~5) the costs incurred during the Reconciliation Period associated with required system upgrades that are not recovered directly from Distributed Generation Facilities pursuant to Section 2.vii;

~~5)~~6) forfeited Performance Guarantee Deposits during the Reconciliation Period pursuant to Section 2.viii which shall be an offset to expense; ~~and~~

~~6)~~7) t~~T~~he costs incurred during the Reconciliation Period for consultants hired to assist the Commission in proceedings involving contract disputes pursuant to Section 2.ix; and~~.~~

8) actual incremental administrative costs incurred as a result of the Company's participation in the Forward Capacity Market;

and

(b) the revenues billed through the LTCRER Factors as approved by the Commission for the Reconciliation Period;

REDLINED VERSION

R.I.P.U.C. No. ~~2125~~2175
Cancelling R.I.P.U.C. No ~~2081~~2125
Sheet 5

THE NARRAGANSETT ELECTRIC COMPANY
LONG-TERM CONTRACTING FOR RENEWABLE ENERGY
RECOVERY RECONCILIATION PROVISION

I_x	=	interest calculated as the sum of the beginning period and ending period balance divided by 2, multiplied by the Company's short term interest rate during period x;
$FkWh_x$	=	The Forecasted kWh for the twelve month period following the effective date of the LTCRER Reconciliation factor; and
UP	=	The uncollectible percentage approved by the Commission in the Company's most recent rate case.

4) ADJUSTMENTS TO RATES

Adjustments to rates pursuant to the LTCRER Reconciliation Provision are subject to review and approval by the Commission. The Company shall file its revised LTCRER Reconciliation factor annually at least forty-five (45) days prior to the effective date of the revised LTCRER Reconciliation factor. Modifications to the factors contained in this LTCRER Reconciliation Provision shall be in accordance with a notice filed with the Commission pursuant to R.I.G.L. § 39-3-11(a) setting forth the amount(s) of the revised factor(s) and the amount(s) of the increase(s) or decrease(s). The notice shall further specify the effective date of such charges.