nationalgrid

Celia B. O'Brien
Assistant General Counsel and Director

July 31, 2015

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4568 – The Narragansett Electric Company d/b/a National Grid Review of Electric Distribution Rate Design Pursuant to R.I. Gen. Laws § 39-26.6-24 <u>Rate Design Proposal</u>

Dear Ms. Massaro:

On behalf of National Grid[1], I enclose ten (10) copies of the Company's revenue-neutral proposal for new electric distribution rates for review and approval by the Rhode Island Public Utilities Commission's (PUC) pursuant to Rhode Island General Laws § 39-26.6-24 (the RE Growth Program Act) in the above-referenced docket. The Company's distribution rate proposal presented in this filing is designed to ensure the costs to run a safe and reliable electric distribution system are recovered across all customers in a fair and equitable manner.

In 2014, the Legislature enacted the Renewable Energy (RE) Growth Program[2] to provide greater availability of grid-connected generation of renewable energy for Rhode Island customers, and to further facilitate the growth of distributed generation (DG) that the DG Standard Contracts Act[3] began. As required by the RE Growth Program Act, on July 1, 2015, the PUC opened this docket to consider rate design and distribution cost allocation among rate classes in light of net metering and the changing distribution system that is expected to include more distributed energy resources, including DG. In this docket, the PUC will determine the appropriate cost responsibility and contributions to the operation, maintenance, and investment in the distribution system that is relied upon by all customers, including all customers with DG and those customers without DG.

Rhode Island can expect an increase in DG through the RE Growth Program, net metering provisions, and energy efficiency programs, as well as other future initiatives to respond to state policies adopted to facilitate the growth of renewable DG. This expected increase in DG, which the Company supports, will necessitate a change in the nature and use of the distribution system to allow greater amounts of customer generation feeding into the system while preserving the safe and reliable delivery of electricity for all customers. In this filing, the Company strives to maintain a balance between appropriately recovering the cost to operate, maintain, and invest in the system, and encouraging customers to become more efficient in their total energy usage. The Company's rate design proposals are designed to begin to move towards fair, equitable and reasonable rates for electric distribution service across all customers and to

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).
[2] R.I. Gen. Laws Ch. 39-26.6.
[3] R.I. Gen. Laws Ch. 39-26.2.

40 Sylvan Road, Waltham, MA 02451
T: 781-907-2153 ■ celia.obrien@nationalgrid.com ■ www.nationalgrid.com

reflect the actual relative cost to serve each customer, both those with and without DG. The key components of the Company's rate design proposals include the following:

- The Company's proposed rates will reduce the amount of its revenue requirement recovered through variable (per kilowatt-hour) charges and increase the amount recovered through customer and/or demand (per kilowatt) charges, yet will create a distinct incentive for customers to conserve their use of energy.

- The Company will implement the proposed rates for each class using currently installed metering for each class.

- The rate structure for Residential Rate A-16 and Small Commercial and Industrial (C&I) Rate C-06 includes tiered customer charges.

- The Company designed the proposed rates so that no individual residential or small C&I customer within Rates A-16 and C-06 will experience a bill change of more than five percent on a total bill basis.

- The Company proposes to consolidate Large Demand Rate G-32 and Optional Large Demand Rate G-62 to simplify and streamline the Company's tariff offerings for its larger C&I customers.

- The Company is proposing a charge applicable to stand-alone DG facilities that will be based upon the size of the facility. In addition, the Company proposes that DG facilities no longer be allowed to net their station service usage against the amount of electricity generated by the DG facility, unless they are specifically enrolling in net metering.

- The Company is not proposing changes to the Low Income Rate A-60, but will consider the appropriate design of the rates for this class in the Company's next electric distribution rate case.

- No changes are proposed for the following rate classes:
  - Rate X-01, Electric Propulsion;
  - Rate M-01, Station Power; and
  - Outdoor Lighting Rates, S-05, S-06, S-10, S-14.

To comply with the RE Growth Program Act, the Company is proposing a re-design of distribution rates that is revenue-neutral (i.e., designed to produce the same level of revenue, no more or no less, than the revenue which current distribution rates were designed to generate) using the revenue requirement and billing units that were approved in the Company's last distribution rate case (Docket No. 4323). The Company is also proposing to use the individual rate class revenue requirements that were determined as part of the allocated cost of service study in Docket No. 4323, including the final revenue allocation. As provided in the RE Growth

Program Act, the proposed rates would take effect for usage on or after April 1, 2016.[4] However, the Company will be required to modify its billing system to implement any new rates approved by the PUC in this docket and is permitted to seek an extension of the April 1, 2016 effective date of new rates, if necessary, to make the billing system changes required to implement a new rate structure.

The Company's filing consists of the joint pre-filed direct testimony, schedules, and workpapers of Peter T. Zschokke and Jeanne A. Lloyd. In their joint testimony, Mr. Zschokke and Ms. Lloyd present the Company's proposed distribution rate re-design and discuss the key factors the Company considered in developing its proposal. They also discuss the role of the distribution utility in a distributed energy world and describe the impact of the future distribution utility on rate design. Finally, Mr. Zschokke and Ms. Lloyd describe the allocated cost of service study used to design the proposed rates, present the typical bills and individual customer impacts of the proposed rate changes, and explain the proposed tariff changes and tariff provisions necessary to implement the Company's rate re-design. A clean version of the amended retail delivery service tariffs and the proposed tariff provisions is attached as Schedule NG-15. The redlined version of the proposed retail delivery service tariffs, identifying the changes to the tariffs currently in effect, and the proposed tariff provisions, is contained in this filing as Schedule NG-16.

The Company's filing is another step in the ongoing evolution of the electric industry towards a sustainable future while ensuring the costs to run a safe and reliable electric distribution system that is relied upon by all customers, including those with and without DG, are recovered from all customers in a fair and equitable manner.

Thank you for your attention to this transmittal. If you have any questions concerning this filing, please contact me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

Celia B. O'Brien

Enclosures

cc: Docket 4568 Service List
Steve Scialabba, Division
Richard Hahn, Division
Leo Wold, Esq.

---

[4] The RE Growth Program Act was amended in 2015 to extend the date by which the PUC must issue an order from December 1, 2015 to March 1, 2016 and the effective date of new rates from January 1, 2016 to April 1, 2016. See 2015 R.I. Pub. Laws c. 59, s. 1.

<u>Certificate of Service</u>

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

__________________________________ <u>July 31, 2015</u>

Joanne M. Scanlon Date

Docket No. 4568 National Grid's Rate Design Pursuant to R.I. Gen. Laws Sec 39-26.6-24
Service List updated 7/16/15

Parties' Name/Address	**E-mail**	**Phone**
Celia B. O'Brien, Esq. National Grid 280 Melrose Street Providence, RI 02907	Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Theresa.burns@nationalgrid.com; Jeanne.lloyd@nationalgrid.com; Ian.springsteel@nationalgrid.com; Peter.zschokke@nationalgrid.com;	781-907-2153
Division of Public Utilities and Carriers Leo Wold, Esq. Karen Lyons, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Klyons@riag.ri.gov; Jmunoz@riag.ri.gov; Dmacrae@riag.ri.gov; Steve.scialabba@dpuc.ri.gov; Al.contente@dpuc.ri.gov;	401-222-2424 Ext. 2218
Richard Hahn Lacapra Associates 1 Washington Mall, 9th floor Boston, MA 02108	rhahn@lacapra.com; apereira@lacapra.com;	
Office of Energy Resources Daniel W. Majcher, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Daniel.majcher@doa.ri.gov;	401-222-8880
Marion Gold, Commissioner Office of Energy Resources One Capitol Hill, 4th Floor Providence, RI 02908	Marion.gold@energy.ri.gov; Nicholas.Ucci@energy.ri.gov; Danny.musher@energy.ri.gov; Christopher.kearns@energy.ri.gov;	401-574-9113
Conservation Law Foundation Jerry Elmer, Esq. Conservation Law Foundation 55 Dorrance Street Providence, RI 02903	jelmer@clf.org;	401-351-1102 Ext. 2012
File an original & 9 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.wilsonfrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107

National Grid

The Narragansett Electric Company

REVIEW OF ELECTRIC DISTRIBUTION RATE DESIGN

Testimony and Schedules of:

Peter T. Zschokke and
Jeanne A. Lloyd

July 31, 2015

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 4568

Submitted by:

nationalgrid

Joint Testimony of
Peter Zschokke & Jeanne Lloyd

JOINT PRE-FILED DIRECT TESTIMONY

OF

PETER T. ZSCHOKKE

AND

JEANNE A. LLOYD

TABLE OF CONTENTS

I. Introduction and Qualifications of Peter T. Zschokke

Q. Please state your name and business address.

A. My name is Peter T. Zschokke. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am Director of Regulatory Strategy for National Grid USA Service Company, Inc., a subsidiary of National Grid USA (National Grid).

Q. Please describe your educational background and training.

A. I received a Bachelor of Arts degree in Economics from Boston University in 1979. I received a Master of Arts degree in Economics from Boston University in 1981.

Q. Please describe your professional experience.

A. I have served as an expert witness on various rate and regulatory matters since 1983. From 1983 through March 1986, I performed rate analyses for Central Vermont Public Service and Boston Edison Company. From April 1986 onward, I conducted regulatory analysis, supported testimony and testified in numerous regulatory proceedings for National Grid affiliated companies in New England, including The Narragansett Electric Company d/b/a National Grid (the Company). I have testified regarding rate designs, allocated cost of service, interruptible credits, real-time pricing rates, cost reconciliation mechanisms and related subjects in front of the regulatory commissions in Rhode Island, Massachusetts, and New Hampshire. In addition, from 1998 to 2000, I managed the function in Rhode Island that served large customer and municipality relationships and delivered the energy efficiency programs. From August 2004 to July 2006, I was on assignment to National Grid's Group Strategy Department in the United Kingdom performing strategic analysis on energy matters of issue to National Grid. Since my return to the United States, I have provided regulatory guidance on capital investment and management audits from a general business perspective, including recovery of investment through cost reconciliation mechanisms. In addition, I testified recently before the Massachusetts Department of Public Utilities (the Department) on behalf of the Company's Massachusetts electric distribution affiliated companies (Massachusetts Affiliates) in the National Grid Smart Grid Pilot program proposal in Massachusetts. I have helped guide the development of the Company's approach to the evaluation of non-wires alternatives to transmission or distribution investment. Recently, I represented the Company's Massachusetts Affiliates in the Grid Modernization collaborative formed by the Department (D.P.U. 12-76) and at technical sessions before the Department in its investigations regarding the results of the collaborative, electric vehicles and electric vehicle charging (D.P.U. 13-182), and time-varying rates (D.P.U. 14-04).

Q. Please describe the dockets in which you previously testified before the Rhode Island Public Utilities Commission (PUC).

A. I have testified in numerous rate and regulatory proceedings before the PUC, including the Company's restructuring plan, mandated by the Utility Restructuring Act of 1996, which was designed to open competition in the marketplace, allowing electric utilities to provide retail access to all customers (Docket No. 2515). Most recently, I represented the Company at a technical session in support of the Company's filing to amend its electric and gas tariffs to address situations where customers request removal of their automated meter reading meters (Docket No. 4342).

II. Introduction and Qualifications of Jeanne A. Lloyd

Q. Please state your full name and business address.

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

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

A. I am a Principal Program Manager in Electric Pricing, New England in the Regulation and Pricing group of National Grid USA Service Company, Inc. This department provides rate-related support to the Company.

Q. Please describe your educational background and training.

A. In 1980, I graduated from Bradley University in Peoria, Illinois with a Bachelor's Degree in English. In December 1982, I received a Master of Arts Degree in Economics from Northern Illinois University in De Kalb, Illinois.

Q. Please describe your professional experience.

A. I was employed by Eastern Utilities Association (EUA) Service Corporation in December 1990 as an Analyst in the Rate Department. I was promoted to Senior Rate Analyst on January 1, 1993. As a Senior Rate Analyst, my responsibilities included the study, analysis and design of the retail electric service rates, rate riders, and special contracts for the EUA retail companies. After the merger of New England Electric System and EUA in April 2000, I joined the Distribution Regulatory Services Department as a Principal Financial Analyst. I assumed my present position on October 1, 2006. Prior to my employment at EUA, I was on the staff of the Missouri Public Service Commission in Jefferson City, Missouri in the position of research economist. My responsibilities included presenting both written and oral testimony before the Missouri Public Service Commission in the areas of cost of service and rate design for electric and natural gas rate proceedings.

Q. Have you previously testified before the PUC?

A. Yes. I have testified before the PUC on numerous occasions in support of various rate-related issues.

III. Purpose of Joint Testimony

Q. On whose behalf are you submitting pre-filed testimony in this proceeding?

A. We are submitting testimony on behalf of the Company.

Q. Mr. Zschokke and Ms. Lloyd, what is the purpose of your joint testimony?

A. The purpose of this testimony is to support the Company's proposed revenue neutral rate design for electric distribution service rates as contemplated by the Renewable Energy (RE) Growth Program Act[1] (the Act) and to present the Company's proposed electric service tariffs.

Q. How is your testimony organized?

A. Section IV describes the statutory requirements for the Company's filing and the factors the PUC must take into account and balance in establishing any new rates in this proceeding. Section V provides an overview of the Company's filing. Section VI discusses the role of the distribution utility in a distributed energy world. Section VII describes the impact of the future distribution utility on rate design. Section VIII discusses the key factors that the Company considered in developing its rate design proposal in this filing. Section IX describes the allocated cost of service study (ACOSS). Section X presents the Company's rate design proposal. Section XI presents a proposed distribution rate for stand-alone generators. Section XII presents the typical bills and

[1] R.I. Gen. Laws Ch. 39-26.6.

individual customer bill impacts of the proposed rate changes. Section XIII presents the Company's proposed retail delivery service tariffs and tariff provisions. Section XIV is the conclusion to our testimony.

Q. Are you sponsoring any schedules today?

A. Yes, we are sponsoring the following schedules:

- Schedule NG-1 Summary of Proposed Electric Distribution Service Rates
- Schedule NG-2 Growth in Use of Solar PV in Massachusetts
- Schedule NG-3 Electric Power Research Institute's (EPRI) "The Integrated Grid: Realizing the Full Value From Central and Distributed Energy Resources" (the EPRI Paper)[2]
- Schedule NG-4 U.S. PV Capacity as a Percentage of Total Capacity Compared With Germany at the Beginning of Its "Energy Transformation" (Figure 2 from the EPRI Paper)
- Schedule NG-5 Estimate of Installed DG in RI through 2020
- Schedule NG-6 Illustration of Customer Diversity
- Schedule NG-7 Relationship between Maximum Monthly kWh and Maximum kW
- Schedule NG-8 Typical Residential Monthly Bill by Component
- Schedule NG-9 Illustration of Customer Savings from Energy Efficiency
- Schedule NG-10 Results of ACOSS and Distribution Revenue [Schedule JAL-1]

[2] Electric Power Research Institute. The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (February 2014), http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733. EPRI is the owner of this material and has provided permission to the Company to include it in this filing.

- Schedule NG-11 ACOSS Unit Costs – Compliance Filing in Docket No. 4323
- Schedule NG-12 Proposed Rate Design
- Schedule NG-13 Typical Bills
- Schedule NG-14 Individual Customer Bill Impacts
- Schedule NG-15 Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions
- Schedule NG-16 Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions, Marked to Show Changes from Those Currently in Effect

IV. <u>Statutory Requirements</u>

Q. Please describe the provisions of the Act that require the PUC to open this docket and the Company to make this filing.

A. The Act was enacted in 2014 to facilitate the development of renewable distributed generation (DG) systems; reduce carbon emissions and environmental impacts; diversify generation resources; promote economic development; enhance the resiliency and reliability of the distribution system; and reduce distribution system costs.[3] As required by Section 24 of the Act, on July 1, 2015, the PUC opened this docket to consider rate design and distribution cost allocation among rate classes in light of net metering for renewable DG and the changing distribution system that is expected to include more distributed energy resources. The PUC will determine the appropriate cost responsibility and contributions to the operation and maintenance of, and investment in, the distribution

[3] R.I. Gen. Laws § 39-26.6-1.

system that is relied upon by all customers, including all customers with DG (net metered renewables and combined heat and power (CHP)) and those customers with no DG.[4]

The Company is making this filing to comply with Section 24 of the Act, which requires the Company to file a revenue-neutral ACOSS for all rate classes and a proposal to re-design distribution rates using the distribution revenue requirement upon which the Company's current distribution rates were set in its last base rate case (Docket No. 4323). As the law permits, the Company has elected to use the ACOSS that the Company filed with its compliance filing in Docket No. 4323. This study was performed using customer load and billing data for calendar year 2012, which the Company believes is still representative of current data.

Q. What is meant by revenue neutral?

A. A revenue neutral rate design for distribution rates will produce the same level of revenue, no more or no less, than the revenue which current distribution rates were designed to generate. For this reason, the Company proposes to use the revenue requirement and billing units that were approved in the Company's last base rate case (Docket No. 4323). The Company is also proposing to use the individual rate class revenue requirements that were determined as part of the ACOSS in Docket No. 4323, including the final revenue allocation, since this study was based on a recent test year,

[4] R.I. Gen. Laws § 39-26.6-24(a).

represents a reasonable and appropriate allocation of costs to each rate class, and formed the basis of current base distribution rates. Finally, the Company's proposals will not require any additional investment in metering, and therefore, no additional increase in revenue requirement. However, any new rate structure that is approved by the PUC will require the Company to modify its billing system to implement the new rates. The Company is requesting recovery of the costs associated with billing system modifications and customer outreach and education that will be incurred to implement the approved rates in this proceeding. A revised version of RIPUC No. 2153, Renewable Energy Growth Program Cost Recovery Provision, reflecting recovery of the administrative costs associated with the implementation of new distribution rates is included in Schedules NG-15 and NG-16.

Q. Is the Company proposing any changes to rate design for any other costs recovered in rates, such as energy efficiency or renewable energy programs?

A. No. The Company's proposal only pertains to changes in the rate design for base distribution rates, which represents approximately 25 percent of a residential customer's monthly bill. The Company is not proposing any changes to other delivery service charges or to supply charges, which are outside the scope of this proceeding. The Act allows the PUC the discretion to address rate design for the equitable recovery of costs associated with energy efficiency and any renewable energy programs that are recovered in rates[5]; however, the Company is not proposing changes to rates for energy efficiency or renewable energy programs.

Q. What are the factors the PUC must consider in establishing new rates in this proceeding?

A. The Act requires the PUC to take into account and balance the following factors in establishing new rates in this proceeding:

(1) The benefits of distributed energy resources;

(2) The distribution services being provided to DG customers when the DG is not producing electricity;

(3) Simplicity, understandability, and transparency of rates to all customers, including non-net metered and net-metered customers;

(4) Equitable ratemaking principles regarding the allocation of the costs of the distribution system;

(5) Cost causation principles;

(6) The General Assembly's legislative purposes in creating the distributed generation growth program; and

(7) Any other factors the PUC deems relevant and appropriate in establishing a fair rate structure for all of the Company's customers.[6]

[5] R.I. Gen. Laws § 39-26.6-24(a).
[6] R.I. Gen. Laws § 39-26.6-24(b).

In addition, the rates for each rate class must be designed in accordance with industry-standard cost allocation principles, which we describe elsewhere in our testimony. The PUC may consider any reasonable rate design options to assure costs are recovered fairly across all rate classes.[7]

Q. Does the Act provide any time frame in which the new rates would become effective?

A. Yes. The Act was amended in 2015 to provide that the PUC must issue an order in this docket by no later than March 1, 2016.[8] The 2015 amendment to the Act also provides for new rates to take effect for usage on or after April 1, 2016. Once the PUC rules on new revenue-neutral base distribution rates in this docket, the PUC may approve changes to the rate design in any future distribution rate case in which an ACOSS is being reviewed, subject to the factors and principles set forth in Section 24(b) of the Act described above. However, the Company is permitted to seek an extension of the April 1, 2016 effective date of new rates, if necessary, to make billing system changes that are necessary to implement a new rate structure.

V. <u>Overview of the Company's Filing</u>

Q. Please provide an overview of the Company's rate design proposals.

[7] R.I. Gen. Laws § 39-26.6-24(a).
[8] 2015 R.I. Pub. Laws c. 59, s. 1.

A. The Company's rate design proposals are revenue neutral and designed to reflect the cost to serve all customers, both customers with and without DG. The proposed rates are designed to move towards fair, equitable, and reasonable charges to all customers. Schedule NG-1 presents the Company's proposed rates in this proceeding. A summary of the Company's proposal follows:

- The Company's proposed rates will shift the recovery of costs through variable (per kilowatt-hour (kWh)) charges to customer and/or per kilowatt (kW) charges yet will create a distinct incentive for customers to conserve their use of energy.
- The Company will implement the proposed rates for each class using currently installed metering for each class.
- The designs for Residential Rate A-16 (Rate A-16) and Small Commercial and Industrial (C&I) Rate C-06 (Rate C-06) include a tiered customer charge.
- The Company designed the proposed rates so the bill impact on any individual customer will be no more than +/- five percent annually.
- The Company proposes to consolidate Large Demand Rate G-32 (Rate G-32) and Optional Large Demand Rate G-62 (Rate G-62) to simplify and streamline the Company's tariff offerings for its larger C&I customers.
- The Company is proposing a charge applicable to large stand-alone DG facilities that will be based upon the size of the DG facility. In addition, the Company proposes that DG facilities, unless they are specifically enrolling in net metering,

continue the practice of not netting the station service usage against the amount of electricity generated by the DG facility.

- The Company is not proposing changes to the Low Income Rate A-60 (Rate A-60) but will consider the appropriate design of the rates for this class in the Company's next electric distribution rate case.
- No changes are proposed for the following rate classes:
  - Rate X-01, Electric Propulsion;
  - Rate M-01, Station Power; and
  - Outdoor Lighting Rates, S-05, S-06, S-10, S-14.

Q. What is the primary objective of the Company's rate design proposals?

A. The Company's objective in proposing new rates in this docket is to begin to move towards rates for distribution service that are fair and equitable across all customers and are designed to reflect the actual relative cost to serve each customer, both those with and without DG. In this filing, the Company desires to maintain a balance between appropriately recovering the cost to operate, maintain, and invest in the distribution system and encouraging customers to become more efficient in their total electricity usage. The Company's revenue neutral rate design filing is another step in the ongoing evolution of the electric industry towards a sustainable future while ensuring the costs to run a safe and reliable electric distribution system are recovered from all customers in a fair and equitable manner.

The Company supports greater use of DG as providing benefits for customers and meeting customer expectations. Rhode Island can expect the RE Growth Program to further the work that the DG Standard Contracts Act[9] began, and provide greater availability of DG for customers in the state. As discussed later in our testimony, other jurisdictions have seen very swift increases in the installation of renewable DG in response to state policies adopted to facilitate the growth of renewable generation. Schedule NG-2 illustrates the growth in DG in the Commonwealth of Massachusetts after policies were established and adopted to promote increases in renewable DG. In addition to Rhode Island laws enacted to facilitate the growth of renewable DG, laws pertaining to energy efficiency goals have resulted in programs that provide incentives to implement large CHP projects within the state. The expected increase in DG from the RE Growth Program, net metering provisions, and energy efficiency programs, and beyond, will necessitate a change in the nature and use of the distribution system to allow greater amounts of customer generation feeding into the system while preserving the safe and reliable delivery of electricity for all customers.

VI. <u>The Role of the Distribution Utility in a Distributed Energy World</u>

Q. Please describe National Grid's vision of the electric distribution utility in the future.

[9] R.I. Gen. Laws Ch. 39-26.2.

A. The future of the electric distribution utility is evolving towards becoming an integrator of load and generation for the benefit of all connecting customers on the distribution system, including those customers who only consume energy, those customers who only generate energy, and those customers who both consume and generate energy. At the same time, customers will continue to expand their use of more energy efficient technologies at their home and place of work. Historically, one-way power flow was the single reason for the distribution grid: the grid delivered kW, kilovolt-amperes (kVA), and kWh to customers on demand. However, the industry is changing with state policy support for local, renewable generation, CHP generation, storage, microgrids (with capability to intentionally island[10] from the distribution system), electric vehicles, and stand-alone generation all connected to the distribution system. The challenge for the distribution utility is mastering the interconnection and potential integration of customer load and customer generation at the local level while still providing low-cost, safe, and reliable delivery of electricity to all customers, among customers, and to markets. The age of continual two-way power flow is upon us.

National Grid expects deployment of renewable DG and distributed energy resources to grow substantially in Rhode Island over the next decade. Experience in other countries and jurisdictions shows that decisions by governments to promote a clean environment

[10] Islanding occurs when a DG facility continues to operate, providing energy to a specific location even though electrical energy from the utility is no longer present.

future result in rapid expansion of distributed solar photovoltaic (PV) generation. The EPRI Paper, a copy of which is attached as Schedule NG-3, describes the issues created in Germany from this same type of expansion and the immediate investments being made to cope with the amount of generation connected to Germany's electric system. As shown in Schedule NG-4, Germany experienced dramatic growth in solar PV generation from 2003 through 2012. The rapid growth in the use of solar PV in Hawaii and California has been well-documented. In both states, and in Germany, the utilities have struggled with catching up to the changes in operation of the electric systems and rate designs to meet the demands created from rapid expansion. Also, on July 1, 2015, California's three large investor-owned utilities filed investment plans outlining the need for significant investments in grid modernization and in real-time management of the local electric distribution system.[11] These examples demonstrate the need to recognize three significant facts: the distribution system must evolve to manage significant two-way power flow; the distribution system and the customers must work together to research and develop ways to integrate customer-sided resources into operation of the distribution system to access value on the system from these resources, when feasible, for both parties; and pricing to recover the costs of the integrated system will need to evolve to recognize the changing nature of the connecting customer.

[11] Pursuant to Public Utilities Code 769 and California Public Utilities Commission order instituting ratemaking (R. 14-08-013), by July 1, 2015, California electric utilities were required to file proposed distribution resource plans to identify optimal locations for distributed energy resources. See http://www.cpuc.ca.gov/PUC/energy/drp/index.htm.

Q. What does this vision of the future imply for the role of the distribution utility?

A. The Company's distribution system is designed and constructed to serve the expected maximum needs of all of its customers (i.e., customers' peak demand) as a group and individually as part of its obligation to maintain the distribution system to serve all of its customers, including customers with DG. For customers with generation, the amount of infrastructure required to serve that customer may not be based only upon the energy that the customer is using, but also the energy that the customer is generating. In some instances, a customer's load (usage) at a given point in time may be less than the output of its generator at the same point in time. When the customer's generation exceeds its usage, that energy is being fed into the distribution system, which is now being used to transport electricity away from the customer, rather than towards the customer as is the case in the traditional role of the distribution utility. In the event the customer's generator tripped off-line due to a failure within the generator system, the amount of electricity needed from the distribution system would increase very quickly since all of the customer's energy requirements would now have to be met by the distribution utility, even for a short period of time. Therefore, the proper cost allocation and rate design must recognize the cost responsibility of the customer for the total of its electricity needs, including when the generator's output exceeds the customer's usage on-site, and when the generator is not operating at all.

In addition, the distribution utility provides other services to DG customers. The EPRI Paper provides a clear description of the services within this design: reliability; voltage quality; access to energy markets; startup power; and efficiency. According to EPRI, a small renewable DG facility at a customer's location would need to spend four to eight times more than the cost of generation to provide these services themselves in an islanded state. This is due to the fact that renewable energy systems (without any energy storage) cannot be used to provide the large start-up power (inrush current) needed by air conditioning compressors and other typical customer motor driven equipment. The parallel connection to the distribution utility provides this needed start-up power. Thus, the distribution utility becomes a required complement to the expansion of clean renewable power because it lowers the overall cost for an individual or company to consider renewable self-generation.

VII. <u>Impact of the Future Distribution Utility on Rate Design</u>

Q. Please describe the impact of the future distribution utility on rate design.

A. All connecting customers, meaning all customers who are connected to the distribution system (i.e., customers with DG, customers without DG, and directly connected DG facilities), should contribute their fair share to the utility's costs to operate, maintain, and invest in the distribution system that is relied upon by all connecting customers. However, under the current rate design which relies primarily upon delivered per kWh charges, especially for residential and small C&I customers and stand-alone generators, DG customers may contribute significantly less to support the distribution system as a result of their reduced kWh usage, thereby shifting the recovery of distribution system costs to all non-DG customers. Establishing the appropriate level of contribution toward these fixed costs by all customers – those with DG and those without DG – is essential to ensuring that the distribution system can be built, operated, and maintained in a manner that allows for DG interconnection in a safe and reliable manner to achieve the clean energy goals of the Act.

Q. Please describe the principles for rate design used in the industry.

A. The industry has long accepted principles of rate design first put forth by James C. Bonbright, which are:

- Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation;
- Effectiveness of yielding total revenue requirements;
- Revenue (and cash flow) stability from year to year;
- Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers;
- Fairness in apportioning cost of service among different consumers (rates based on cost causation);
- Avoidance of "undue discrimination"; and

- Efficiency, promoting efficient use of energy by the customer (e.g., such that utility's infrastructure and resources are not strained).[12]

Using these principles as a guideline, the ideal rate design for all customer classes would consist of a customer charge designed to collect (1) customer-related distribution system costs, such as the cost of a meter, billing, and customer service, plus (2) a demand charge that recovers the demand-, or capacity-, related system costs. The demand charge would be assessed on a measurement of customer size, such as maximum connected load or maximum use during a 15-minute interval, and would reflect the customer's relative contribution to system cost relative to other customers' demand.

A demand rate charges customers for their maximum use during a specific time period and provides customers an incentive to lower their use during that time period, and ultimately reduce their billed charges. As customers improve their individual load pattern through use of demand side management activities, system and distribution system utilization will improve. Encouraging customers to shift load from high use, peak periods into off-peak periods results in a better utilization of the existing distribution system and other elements of the electric system by reducing the number of hours that the distribution system must be available to serve peak loads. Theoretically, the utilization across all hours could reach very high and consistent levels. If achieved, there would be

[12] James C. Bonbright. Principles of Public Utility Rates (1st ed. 1961).

less need for time differentiation of demand charges or energy rates. Any consideration of rate design and its stability over time must consider this possibility. Better utilization of the system also reduces the need to build additional system capacity to meet peak loads that occur for as few as 20 to as many as a few hundred hours per year. Given the high fixed costs in the industry, reducing capacity requirements will ultimately result in reduced distribution system investment and, ultimately, a lower cost to be recovered from customers. Advocates for the use of storage technologies argue in favor of demand rates because these rates provide economic value to the system and provide an economic opportunity to customers to consider use of storage technology.

Other benefits of demand charges are that the rates would communicate appropriate price signals to customers consistent with cost causation (i.e., the distribution system costs are incurred to meet customer demand during the periods of highest demand) and reflect the marginal cost of the distribution system. The rates would be fair and equitable as customers would pay their fair share of the costs incurred by the utility to provide safe and reliable service to all customers (i.e., customers with and without DG). Most importantly, demand rates would provide incentives to customers to manage their demand during all hours of the day through choices in their behavior and/or activities as well as choices in the technology they select for their appliances and/or equipment. The timing of certain activities (e.g., when to charge an electric vehicle), could be managed to reduce the demand for, and use of, the distribution system during peak periods, creating efficiency that helps improve operational efficiency and the life of company assets.

Q. Does the Company currently offer demand-based rates to its customers?

A. Although the Company does offer rates with demand-based charges to its medium and large C&I customers, the Company is limited in its ability to implement demand-based rate designs for residential and small C&I customers because new, higher-cost metering necessary to measure kW is not typically installed for customers in these rate classes. In addition, significant outreach and education would be needed to provide customers with the information necessary to comprehend the advantages that demand-based rates provide to them.

Q. Earlier in your testimony, you stated that the proposals in this filing are intended to achieve the Company's primary objective of ensuring that the rates billed to every customer are fair and equitable, and are designed to reflect the actual cost to serve each customer, both those with and without DG. Please explain how the Company's proposals achieve this objective and move rates toward the Company's ideal rate design.

A. The Company's rate design proposals generally reflect a shift from recovering distribution system costs through variable per-kWh charges to customer and/or per-kW charges that reflect customer size. The proposed charges are based upon the size of the customer and will be applicable to all customers, including those customers who have installed DG. Customer size is determined by metered kWh use for customers without demand meters and by actual measured demand for larger customers receiving service on a demand rate class.

The result of the Company's base distribution rate proposals in this filing is that the proportion of the revenue requirement billed through customer and demand charges will increase modestly from the current design. Given this modest shift, transitioning more recovery of revenue requirement through the customer and demand charges would occur over several years.

Q. What is the framework for the Company's rate design proposals in this filing?

A. As a step toward recovering a greater proportion of distribution system costs through fixed charges that reflect customer size, the Company is proposing a four-tiered customer charge for the Rate A-16 and Rate C-06 rate classes. Each tier is defined by a kWh range intended to reflect customers' monthly maximum use. The customer charges are designed to recover most or all of the customer-related revenue requirement and a portion of the demand-related revenue requirement based upon the billing determinants of the applicably-sized customers in each tier. As a result, customers will be billed the customer charge associated with the tier that is representative of their maximum monthly use over a 12-month period. The remaining distribution revenue requirement is recovered through a uniform per-kWh charge.

For those C&I rate classes with a rate structure that already includes demand charges (i.e., Rates G-02, G-32, and G-62), the Company is proposing to set customer charges that will recover the customer-related revenue requirement and to increase the respective demand charges to recover the remaining demand-related revenue requirement for each rate class, subject to the impacts such changes will have on customers' bills in these rate classes. In addition, the Company is proposing to consolidate Rate G-32 and Rate G-62 because the cost to serve customers in these two rate classes, on a per unit basis, is substantially similar.

One overarching criteria that the Company has adhered to in designing all the distribution rates for each rate class affected in this filing is that no residential or small commercial customer within each rate class (Rates A-16 and C-06) will experience a bill increase or decrease of more than five percent on a total bill basis. The same guideline was used in designing the charges for the medium and large C&I classes as well; however, because of the variability in usage characteristics (i.e., per kW and per kWh consumption), some of the customers in each of those classes fall outside of the +/- five percent limits. However, even for those customers, the Company believes that the bill impacts are reasonable.

Q. Why is the Company proposing to recover more of the distribution system costs through customer and/or per-kW charges rather than variable (per-kWh) charges?

A. Customer and demand charges are more reflective of the underlying cost of the distribution system and, therefore, communicate more accurate price signals to customers regarding the costs that customers impose upon the system. As discussed previously, the distribution system is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand and, once constructed, distribution system costs are fixed in nature. In other words, reducing energy consumption does not result in a corresponding reduction in distribution costs. Therefore, as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible.

Historically, the Company has relied upon metered kWh deliveries as the basis of assessing distribution charges to residential and small C&I customers. This means that each customer's contribution to the class revenue requirement is based upon that customer's monthly or annual kWh consumption, even though the customer's actual contribution to costs is based upon the customer's maximum demand (kW) use, on the system (i.e., the customer's maximum use at a point in time). As a customer's annual kWh consumption increases, or decreases, the customer's contribution to revenue also increases, or decreases, accordingly, even if the customer's maximum demand does not change. For example, the following table compares the monthly bills of three residential customers, each of whom has an annual maximum demand of 2 kW:

Table 1

Customer	Annual kWh Use	Annual Distribution Charges
1	3,000	$109.92
2	5,000	$183.20
3	10,000	$366.40

As illustrated in Table 1, even though each customer's contribution to distribution system cost, as measured by the customer's maximum demand, is the same (2 kW each month), each customer has a significantly different annual contribution to revenue. Consider Customer 1, for example, whose annual kWh use is relatively small. This customer could be a seasonal customer, who uses electricity for only a few months of the year, or a solar DG customer who requires fewer kWh deliveries from the Company during the summer months, but a significant amount during the winter. Although the customer's demand on the system is identical to the other two customers, the customer contributes less to the Company's revenue requirement because of the current rate design that relies on per-kWh charges to bill out revenue.

Thus, the current pricing approach may lead to inequitable revenue requirement recovery from customers with regard to distribution system costs. The accelerated growth of DG in recent years (see Schedule NG-5) resulting in the reduction of Company-delivered kWh to some of those customers, has focused attention on the need to design rates that better reflect cost causation and result in more equitable revenue requirement recovery from all customers, including those with DG.

Q. How does this proposal to recover more distribution system costs through tiered customer charges affect customers with DG?

A. Because more of the distribution system's costs will be recovered through the tiered customer charges, a customer's monthly bill for distribution service will be less affected by a reduction in kWh usage than under the current rate design. Since the Company's proposal is to begin the movement of aligning the recovery of fixed distribution system costs by designing rate levels in a way that should provide for more recovery than in the current customer charges, the tiered customer charge design will result in a more equitable contribution to costs by customers with DG.

Q. Please describe in more detail the design of the four-tiered customer charge applicable to Rate A-16 and Rate C-06.

A. Each of the four tiers would be defined by a kWh range intended to reflect customers' monthly maximum use. The customer charge for each succeeding tier will be higher relative to the prior tier and is intended to approximate what customers would be charged through a combination of a customer charge and a demand (per kW) charge. The customer charges would be designed to recover most, if not all, of the rate class's customer-related revenue requirement from the last rate case and a portion of the demand-related revenue requirement associated with the applicably-sized customers in each tier. The tiered customer charge design will more accurately reflect customer distribution system cost responsibility and will also encourage customers to manage energy use wisely in order to remain in their current tier or move to a lower tier.

Q. How does a tiered customer charge structure approximate a demand charge structure?

A. Under a rate structure where a customer's monthly bill is based upon maximum demand, each customer's monthly charges would consist of a customer charge and a per-kW charge based upon the customer's maximum kW demand. Typically, the demand charge would be the same every month and would not vary with kWh consumption. However, larger-sized customers would pay a higher demand charge than smaller customers reflecting their larger size and use of the distribution system and, consequently, the greater cost that they impose on the distribution system. The tiered customer charge design mirrors this design. However, given that the Company has established bill impact limits as part of its proposal, both Rates A-16 and C-06 will still include a per-kWh charge to mitigate the bill impacts on smaller customers of increases in the customer charge.

Q. How did the Company determine that the appropriate number of tiers for the customer charge?

A. The Company decided that a proposal to implement a tiered customer charge where the customer charge is determined based upon the size of a customer as determined by that customer's kWh usage would be most appropriate from reactions to proposals to implement fixed charges in other states. Nearly all proposals in other states raised the customer charge to a uniform amount regardless of customer size. The proposals created significant debate not only about the need for the increase in the customer charge, but also about disproportionate bill increases to small customers while larger customers received bill reductions because the customer charge increase was more than offset by the reduction in the per-kWh charge, resulting in more costs being recovered from smaller customers. The proposals went against many accepted rate principles first promulgated by Bonbright: gradualism, fairness, cost reflective, etc. However, those proposals were made by the utilities in an effort to improve the effectiveness of recovering the revenue necessary to operate, maintain, and invest in the utility's system, another Bonbright principle for rate design.

Any design for rate classes without demand meters must reflect a simple fact: larger customers use more of the system than smaller customers. Rates that reflect the cost of the system is another important Bonbright principle, which should be considered as we transition into the new world of distributed energy. One customer charge for a whole class cannot reflect this fundamental element that customers with higher demands should pay proportionately more for their use of the distribution system than customers with lower demands.

The third consideration in this decision was the recognition that our proposal could not result in relatively large bill impacts to customers. The Company set a limit of no more than a five percent change in the total bill as a result of the change in rate design proposed for residential and small C&I (Rate C-06) customers in this filing. Any design would need to meet this characteristic while increasing the amount of revenue being recovered from the customer charge.

The Company's final consideration was recognition that the current Rate A-16 customer charge of $5.00 was not high enough to recover the customer-related costs of $7.57 per bill as established in the Company's last rate case (Docket No. 4323). The ability of the Company to recover the customer costs alone would be hampered by limiting the number of tiers. However, the Company recognized that too many tiers would have the opposite effect from simplicity and could create customer confusion.

The Company considered each of these issues and decided that four tiers would be a reasonable solution to bringing rates more in line with cost incurrence. Fewer tiers would create issues similar to those found in other jurisdictions. A greater number of tiers allows for improved fine-tuning of the rate design and improved recovery of the revenue requirement through increasing customer charges associated with the size of a customer. However, too many tiers can cause confusion. Therefore, the Company decided four tiers would be a reasonable proposal.

Q. Why is the monthly charge based upon a customer's maximum monthly kWh use over 12 months rather than the customer's kWh use in the current billing month?

A. As indicated above, the distribution system is sized and constructed to accommodate the maximum demand on the system at a single point in time. Therefore, a customer's maximum kWh usage during a 12-month period reflects the customer's contribution to total system demand and, therefore, the customer's cost responsibility.

Q. But customers' maximum demands do not all occur at the same point in time, do they?

A. No. Customers' maximum demands occur at various points in time throughout the day and the year. This concept is known as diversity of demand. System planners are aware of diversity of demand on the system and account for that in their system design. The costs of system design are embodied in the Company's cost of service. Thus, all customers get the value of diversity through the total revenue requirement.

Schedule NG-6 is an example of customer diversity of demand. As seen in this example, each customer has an almost equivalent amount of maximum demand, 2.0 to 2.5 kW.

However, each customer's maximum demand occurs at different times. At the time of the coincident peak (i.e., the maximum use at a single point in time of all three customers), the largest demand is attributed to one customer at 2.5 kW while the other two customers each add 1.5 kW. However, if that large customer did not exist or used far less, other hours and other customers would serve to determine the largest demand. Fairness would require customers pay for their maximum demand on the system since each customer relies on the system to have capacity to deliver electricity. As the chart shows, many customers need their individual capacity at many different times. There is no one time or one customer that is necessarily singly responsible for the capability of the electric system.

Q. Since customers total maximum demands are larger than coincident demands, won't using maximum demand as the basis for the customer charge result in overcharging customers?

A. No. Diversity of demand is reflected in the design of the distribution system. The Company does not plan or design its electric system in a manner that identifies each individual customer's peak demand.[13] In designing the distribution system, the Company considers the overall peak demand in an area, which reflects the diversity of the customer load in that area. Designing the system in this manner results in an overall lower total

[13] The exception is when a customer elects second feeder service at a given level of capacity. In that instance, the amount of requested capacity is reserved for that customer to use instantaneously and distribution planners factor that reservation into any system expansion considerations.

cost of service for the utility than would result if the utility designed the system to meet the individual peak demands of each customer. Also, when developing rate class allocation factors utilized in the ACOSS to determine rate class revenue requirement, the Company uses demand data that accounts for diversity of demand. Therefore, each class's revenue requirement appropriately reflects the diversity of demand associated with that rate class.

Because the ACOSS reflects lower costs from customer diversity, the rate design becomes an instrument to recover the costs to provide the service and to signal to customers the costs to provide the service so that they may make decisions that can contribute to the greater efficiency of the electric system. Any rate design must meet Bonbright's principle of being understandable as well as reflective of costs. Use of the customer's own maximum monthly use, or demand, during a 12-month period to reflect the customer's need of the system adheres to these principles. During the year, customers pay fairly for their use of the system based upon their size and can lower their use to reduce their customer charge and total bill during the following year. With this rate design, a customer can improve energy efficiency and, depending on the impact of those improvements on the customer's overall use, the customer may move to a tier with a lower customer charge. Improvements in customer efficiency can allow the Company's system to remain in service longer as maximum demands on the system are lessened through the use of proper price signals.

Q. How did the Company determine that using a customer's maximum monthly kWh is a good approximation for kW?

A. The Company analyzed the relationship between kW and maximum kWh for approximately 200 residential and 60 small C&I load research customers using three years of data. Schedule NG-7 is a graphical representation of the data, with the Rate A-16 data shown on page 1 and the Rate C-06 data on page 2. The horizontal axis of each graph is each customer's maximum hourly demand (kW) during the year. The vertical axis shows the customer's maximum monthly use (kWh) during the year. Although there is much variation in the data, meaning that for any given level of kW, there is a wide-range in the associated maximum kWh use, the bulk of the observations are clustered around the trend line shown on the graphs. Therefore, the Company concluded that maximum kWh use can be reasonably expected to approximate customer size, as measured in kW.

Q. Does the Company believe that the proposed rate designs will be easily understood and accepted by customers, both with and without DG?

A. Yes. The proposed design is simple: one customer charge for 12 months if you fall within a range of use for that time period. Customers are provided the most recent 12 months of use on their bills every month. Thus, customers are well-equipped to decide if they must act and by what degree to avoid a specific customer charge. Customers will be aware of which tier they will be in simply based upon their last 12 months of kWh use.

As designed, no customer will see a significant increase in their total bill relative to their total bill based on current charges. As indicated previously, the Company is proposing changes only to the base distribution charges in this proceeding. Schedule NG-8 illustrates a monthly bill for a typical residential customer using 500 kWh per month. As shown on this schedule, the distribution portion of the bill accounts for only approximately 25 percent of the total bill. Therefore, even a relatively large increase in the distribution charge will have a relatively small effect on the customer's total bill. However, even though the overall bill impacts will not be substantial, the Company will need to prepare customers with appropriate informational and outreach so that they can adapt to the change in the rate structure to take advantage of the opportunities presented in the new design to reduce usage and charges.

Q. You've stated that the proposed rate design will encourage energy efficiency. Please elaborate.

A. Customers will need to be conscious of their energy consumption throughout the month to avoid moving to a higher tier with a higher customer charge. In addition, customers will have the opportunity to move to a lower tier, with a lower customer charge by aggressively managing their usage or implementing energy efficiency measures.

Q. How are the savings from implementation of energy efficiency measures reflected on customers' bills?

A. Schedule NG-9 illustrates how implementation of energy efficiency affects customer bills. Using an example of a customer who reduces monthly usage from 1,000 kWh to 500 kWh, this schedule shows how each component of the customer's bill is affected by the reduction in kWh use. Page 1 of this schedule illustrates the bill impact using rates currently in effect. Because most of the charges currently billed to customers are kWh charges, the effect of the reduction in usage is primarily reflected in those components with the highest per kWh charges. As shown on Line 15, the savings in commodity charges accounts for one-half of the total bill savings.

Q. How will the proposed rate design affect the savings of customers implementing energy efficiency?

A. Page 2 of Schedule NG-9 shows the savings realized by the same customer who reduces monthly use to 500 kWh from 1,000 kWh is $5.40 less than the savings the customer would realize under the rates currently in effect. After 11 months, the customer's savings will be only $0.71 per month less than the savings under the current rates because the customer's reduction in maximum usage allows him to move to a tier with a lower customer charge in the following year.

Q. Why must the customer wait 11 months to realize the savings in the customer charge?

A. When customers reduce kWh use, the bill savings are reflected immediately through reduced billings associated with kWh charges. However, since the cost of the distribution system is fixed in the near term, there is no associated immediate reduction in distribution system costs from a reduction in customer consumption. The customer's past historical maximum use reflects the customer's contribution to the distribution system peak and, therefore, that customer's cost responsibility for the existing system. However, if the customer's reduction in use, and demand, is permanent, that reduction in use will eventually lead to lower capacity requirements and reduced system costs. Therefore, using the customer's maximum monthly kWh use to determine their customer charge for the following 12 months results in more equitable recovery from customers and better reflects the concept of cost incurrence.

Q. What are the challenges to implementing further rate design changes in the future?

A. The Company recognizes that any application of new metering systems may provide opportunities to implement new rate designs, such as residential demand charges and various forms of time varying rates. In addition, tools will be available for customers to access their detailed usage and make changes to manage their use of the distribution system. However, implementation of a new metering system requires a significant capital investment that requires prior analysis and careful planning. A cost benefit analysis that clearly identifies the goals, expected outcome, and cost is important. As part of any metering system change, the Company would need to conduct significant outreach to, and education of, customers to help them understand the changes that would be coming, what they would mean to the customer, and the value to be gained from managing their electricity demand using tools that would be made available to them to do so.

Q. What is your recommendation for next steps towards achieving the Company's vision?

A. The Company recommends implementing rate designs to provide financial incentives to motivate customers to manage their load, and then provide tools to assist them in doing so. Advanced or smart metering could be considered in the future as a potential tool to assist customers in managing their use.

VIII. <u>Key Factors for Consideration in Developing the Company's Proposal</u>

Q. Please describe what factors the Company took into account in designing its proposals for new rates in this proceeding.

A. The Company is attempting to maintain a balance between appropriately recovering the cost to operate, maintain, and invest in its distribution system and encouraging customers to become more efficient in their use of the system, as measured in kWh usage, both kWh delivered and kWh generated and exported onto the system. The Company's proposals take into account and balance many factors, including equitable ratemaking and cost allocation principles and the General Assembly's legislative purposes in creating the RE

Growth Program, with the goal of designing rates that do not discourage implementation of DG nor provide a subsidy to DG customers which would understate the true cost to provide electric service.

Q. In Section VII, the Company describes how its rate design proposals are fair and equitable for all customers and reflect cost causation principles. Does the Company's proposal also take into account the benefits of DG?

A. DG has the potential to provide capacity relief in local areas having distribution system constraints. Therefore, any compensation for benefits that DG might bring to the Company and its customers is specific to the condition that is causing the constraint and the time over which distribution system investment can be deferred. As part of the RE Growth Program annual filing requirement in 2016, the Company will be evaluating the use of localized credits in 2016 for locations where DG would be helpful.

Q. Does the Company's DemandLink[14] pilot provide insight into such benefits?

A. It does, in the fact that the pilot will provide insight as to the value of localized load reduction; however, although there are potential benefits of DG, there is also a cost that

[14] The Company's DemankLink pilot, also known as the Tiverton pilot, is a load curtailment pilot program to test the use of load curtailment by customers, or demand response, as a means to manage local distribution capacity requirements during peak periods and was first proposed by the Company in its 2012 System Reliability Plan Report and approved by the PUC in Docket No. 4296.

DG imposes by virtue of connecting to the system, as discussed later in this testimony in Section XI.

Q. Please explain how the Company took into account the General Assembly's legislative purposes in creating the RE Growth Program.

A. One of the legislative goals of the RE Growth Program is to encourage the growth of renewable DG. Therefore, any new rates proposed by the Company should not be designed to discourage implementation of DG. However, neither should new rates be designed to provide a subsidy to DG customers and, therefore, understate the true cost to provide service. Rates that apply equally to all customers, both those with and without DG, will communicate accurate price signals that reflect the cost of providing service to the customer so that the customer may make informed and economical decisions regarding the installation of DG. As the RE Growth Program requires on-site load to be separately metered from generation, there is no specific revenue loss associated with displaced kWh deliveries for projects under the program;[15] however, once the RE Growth Program annual solicitations have ended (in 2021), only standard behind-the-meter net metering will be available to compensate future DG customers. As a result, the revenue loss associated with kWh deliveries displaced by on-site generation will continue to grow

[15] Bill credits, based on the RE Growth Program customer's on-site load, will be applied to each customer's monthly bill. These credits represent the revenue displaced by the customer's generation. The credits will be tracked and recovered from all customers through the RE Growth Program cost recovery mechanism.

and non-DG customers will have to pay for this lost revenue absent this needed rate design reform.

IX. Allocated Cost of Service Study

Q. Please describe the ACOSS approved in Docket No. 4323 that is used as the basis of the proposed rates in this proceeding.

A. The ACOSS approved in Docket No. 4323 is included as Workpaper NG-1. This schedule originally appeared as Amended Attachment 3A in the Amended Settlement Agreement filed with the PUC on November 14, 2012, and as Compliance Attachment 3A in the Company's compliance filing filed with the PUC on January 24, 2013.

Q. What is an ACOSS and why is it prepared?

A. The purpose of an ACOSS is to apportion fairly a utility's total revenue requirement, including plant and other investments, operating expenses, depreciation, and taxes among the rate classes served by the utility. The ACOSS produces a revenue amount for each rate class equal to the revenue that needs to be collected from that class to produce the system average rate of return on rate base. This information provides valuable guidance in revenue allocation, and in the development of rates, to recover the utility's overall revenue requirement from all rate classes.

Q. How is an ACOSS prepared?

A. Each element of the utility's total revenue requirement is analyzed and assigned to, or allocated among, the rate classes. A three-step process is traditionally used to analyze each element of the revenue requirement. The first step is functionalization of each element. In the functionalization step, costs are separated by the utility's basic service functions. For the Company, these functions are distribution capacity-related costs, categorized by voltage level, and customer-related costs. The distribution system capacity-related costs include substations, conductors and all other costs associated with delivering electricity through the distribution system. The customer function includes the cost of the meters, a customer service and billing system, the cost of meter reading, and other costs supporting these activities and associated with being a customer of the distribution company.

The second step is to classify each functionalized cost element as Demand, Energy, or Customer. In the classification step, the previously functionalized accounts are separated into Customer, Energy, or Demand, according to the system design or operating characteristics that cause them to be incurred. Customer-related costs are incurred to attach a customer to the distribution system, to meter the customer's usage, and to maintain both customer-related distribution assets and the customer's account. Customer-related costs are primarily a function of the number of customers served, and they continue to be incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile. The Company's customer-related costs include capital costs associated with services and meters, and operating costs such as customer service, field service, billing, and customer accounting. Demand-related, or capacity-related, costs are associated with utility plant that is designed, constructed, and operated to meet system peak demand or non-coincident class peak demand.

The final step, class allocation, is the allocation of each functionalized, classified cost element among the rate classes. In the class allocation step, the functionalized, classified costs are allocated among the rate classes based on causal relationships. These relationships are determined by analyzing the Company's system design and operations, its accounting records, and its system and customer load data. Based on those analyses, direct assignments of costs, as well as cost allocators, can be chosen for each asset and cost.

Q. How were assets and costs in the distribution revenue requirement allocated among the rate classes?

A. Selection of the appropriate approach for functionalizing, classifying, and allocating each component of the revenue requirement was based on careful consideration of cost causality, as well as prior Company methodology, PUC precedent, and utility practice as stated in the *Electric Utility Cost Allocation Manual* (January 1992) of the National Association Of Regulatory Utility Commissioners. Cost causality means the cause and effect relationships between customer requirements, load profiles, and usage characteristics on one hand, and the costs incurred to serve those requirements on the other hand. Demand-related assets were allocated in proportion to the non-coincident peaks (NCP) (i.e., the maximum demand of the class) at the appropriate service level. NCP allocators were used because they reflect the diversity of demand on the system; that is, rate classes peak at different times and the system is designed to meet demand at all times. Customer-related costs are allocated based on number of customers and/or meters used by each rate class.

The final step prior to designing rates is to evaluate the results of the ACOSS and re-distribute revenue requirement among the classes based upon established criteria in consideration of Bonbright's principle of gradualism, such that no rate class, even if receiving an allocated share of the revenue requirement that results in a fully equalized rate of return, would experience a significant impact as a result.

Q. What were the final class revenue allocations approved in Docket No. 4323?

A. Schedule NG-10 is a summary of the results of the ACOSS and the final rate class revenue allocations approved in Docket No. 4323. As part of the revenue allocation process, the Company limited the increase to certain classes based upon bill impact considerations. The "capped" revenue was re-allocated to the other rate classes. In addition, a subsidy to Low-Income rate class A-60 was approved, and the subsidy was also re-allocated to the other classes.

Q. Please describe the information on Schedule NG-11, Unit Costs by Functional Classification.

A. Schedule NG-11 reproduces Schedule HSG-1C from Docket No. 4323 and presents a summary of revenue requirements by functional classification. It also presents the results of the ACOSS on a unitized basis; the units for each functional classification are shown on the schedule. This information is useful in developing rates and as a check on the reasonableness of the results, because the unitized costs for demand-related functional classifications are expected to be similar across the rate classes.

X. Rate Design Proposal

Q. What is the purpose of the rate design process?

A. In general, the purpose of the rate design process is to determine rates that will produce the revenue for each rate class as determined in the revenue allocation process. The purpose of this filing is to redesign rates that are more sustainable in meeting Bonbright's principles of reflecting the cost-to-serve, and to ensure adequate revenue to the utility. The rate design proposals in this filing are the first step towards those goals, and are necessary in light of net metering and the changing distribution system that is expected to include more distributed energy resources, including, but not limited to, DG. This will help ensure that the costs to run a safe, reliable electric distribution system are recovered from all customers in a fair and equitable manner.

Q. Is the Company proposing new rates for all of the current rate classes?

A. No. The Company is not proposing any changes to the rates for rate classes X-01 (Electric Propulsion), M-01 (Station Service), or Outdoor Lighting Rates S-05, S-06, S-10, or S-14.

Q. Why is the Company not proposing any changes to the rates for these classes?

A. The Company's rate design proposals result in a shifting of cost recovery through variable (per kWh) charges to customer and/or demand (per kW) charges to ensure that customers who reduce kWh consumption either through implementation of DG, or energy efficiency will pay their fair share of the costs associated with the Company's distribution system. The rate classes listed above have limited opportunities for implementation of DG or energy efficiency. In addition, the rate designs for these classes already consist primarily of fixed charges; therefore, it is not necessary to propose new rates.

Q. Please discuss the nature of service and the current rate design for Rates A-16 and A-60.

A. Rate A-16 is the Company's regular residential rate class. Rate A-60 is available to low-income residential customers who meet the criteria specified in the tariff. The current distribution rate structure for Rate A-16 includes a monthly customer charge and a per kWh charge.

Currently, Rate A-60 has no monthly customer charge and only a per kWh charge. Rate A-60's distribution rates are designed so that a customer on Rate A-60 using an average number of kWh has a total bill that is approximately 50 percent of the total bill for a customer on Rate A-16 with the same usage.

Q. How does the design of the current rate compare to the cost of service-based unit charges shown on Schedule NG-11?

A. Rate A-16's current customer charge of $5.00 per month is less than the full cost of service customer charge of $7.57 per month shown on Schedule NG-11, page 1, line 25 for the Residential Class. Therefore, customers with low average annual usage, whose total monthly distribution charges are less than $7.57 per month, are currently being subsidized by larger customers. In addition, the revenue requirement not recovered through the customer charge component is currently recovered through a per kWh charge, which is applied to monthly kWh deliveries and does not necessarily reflect the customer's maximum demand.

Q. What is the proposed rate design for Rate A-16?

A. The first step in designing rates for Rate A-16 is to design the four-tier customer charge described earlier in the testimony. The proposed tiers and charges are as follows:

Tier 1:	0 kWh to 250 kWh	$5.25 per month
Tier 2:	251 kWh to 750 kWh	$8.50 per month
Tier 3:	751 kWh to 1,200 kWh	$13.00 per month
Tier 4:	kWh in excess of 1,200	$18.00 per month

Q. How were the tiers' ranges determined?

A. The tiers' ranges are designed to be broad enough to allow customers to manage their monthly use to remain in their current tier, but narrow enough to allow for the opportunity to move to a lower tier through implementation of energy efficiency measures. The Company performed an analysis by applying statistical and graphical analysis techniques to Company billing data and class load research data to aid in selection of the kWh within the tiers. Approximately one-half of the residential customer bills will fall into the first and second tiers, with the remaining one-half in the upper two tiers. The initial tier range is 0 kWh to 250 kWh. Since the proposed charge for the initial tier is less than the customer-related cost of service unit charge of $7.57 per month, the Company is proposing that the range for the initial tier be narrow in order to limit the number of customers being subsidized. An analysis of the load research data shown on Schedule NG-7 indicates that a small cluster of a few customers have maximum use in the range of 0 kWh to 250 kWh. Analysis of the Company's billing data indicates that less than 15 percent of residential customers have a monthly maximum use within that range.

Q. Please describe the analysis used to determine the tiers in greater detail.

A. The Company evaluated load research data to aid in the selection of the tiers. To investigate the relationship between maximum monthly kWh use and maximum kW, the Company used a residential data sample of approximately 200 customers with data points over three years, and a variety of statistical analyses including correlation analysis, probability analysis, and scatter plots analysis. Workpaper NG-2 includes charts that illustrate the results of the Company's analyses.

Next, the Company performed various customer and bill frequency analyses using calendar year 2014 monthly billing data. First, the billing data was "scrubbed" by eliminating any adjusting bills, and limiting the bills being analyzed to those that fit into a normal billing cycle (26 to 36 day); therefore, not allowing adjustments, short-cycle or long-cycle bills to bias the analysis. After the scrubbing process was completed, a bill frequency analysis, based on monthly customer and kWh data, was prepared showing number of bills and kWh usage by defined kWh ranges. Separate frequency analyses were developed for average annual kWh and maximum monthly kWh by billing account showing the number of customers and the kWh usage in each kWh range. Workpaper NG-3, page 4, shows the residential frequency analysis on maximum monthly kWh by account. Using this analysis, the Company was able to determine the kWh ranges that corresponded to the desired number of customers in each tier.

Q. How were the charges for each tier determined?

A. As explained earlier in the testimony, ideally, the customer charge in each tier will recover the customer-related and demand-related costs associated with the size of the customer assigned to each tier. However, increasing the fixed customer charge relative to the kWh charge will produce bill increases or decreases for each customer that vary depending upon the customer's actual usage. Therefore, the Company's criteria of limiting impacts to +/- five percent on the total bill limits the amount of the increase in the customer charge for each tier.

As noted earlier in our testimony, Rate A-16's current customer charge of $5.00 per month is substantially below the full cost of service unit charge of $7.57 determined in the ACOSS. The proposed customer charge of $5.25 for the first tier is designed to move the customer charge closer to the full cost of service level while adhering to the bill impact criteria of +/- five percent for all customers in the tier. The proposed customer charge of $8.50 for the second tier is designed to recover the customer-related costs; however, to limit bill impacts to low-use customers in the tier, only a small portion of the demand-related costs are included in this charge. The charges for the third and fourth tiers recover the customer-related costs and approximately half of the demand-related costs.

In total, approximately 40 percent of the Rate A-16 revenue requirement is designed to be recovered through the four customer charges, as compared to 18 percent based upon the current design.

Q. Please describe the proposed design of the energy-based rate for Rate A-16.

A. The second step in the rate design for Rate A-16 was to design the per kWh charge, which is uniform (i.e., the same kWh charge for all sizes of customers) that will recover the remaining rate class revenue requirement not recovered through the customer charges. The rate necessary to produce the rate class's revenue, and to reflect the Rate A-60 discount of 50 percent, is shown on Schedule NG-12, Page 1.

Q. What is the proposed rate design for Rate A-60?

A. The Company is proposing no changes to the current design for Rate A-60, but will address the appropriate design for this rate class in the Company's next general rate case. Since there will be no change in distribution rates, there will be no bill impacts for customers receiving service on this rate class as a result of the Company's proposals in this filing.

Q. Please discuss the nature of service and the current rate design for Rate C-06 class.

A. Rate C-06 is available for all purposes; however, the Company may require customers with 12-month average demand exceeding 200 kW to take service on the Large Demand Rate G-32. Rate C-06 includes customers receiving unmetered service.

The current distribution rate structure for Rate C-06 includes a monthly customer charge and a per kWh charge. There is an additional charge if the customer requires a transformer in excess of 25 kVA. Unmetered customers pay a location charge, which is intended to reflect the customer charge less a credit for meter-related costs, in place of paying a customer charge.

Q. What are the proposed rates for Rate C-06?

A. The Company is proposing to implement the same four-tier customer charge design for the Rate C-06 customer charge as it is proposing for Rate A-16. The proposed tiers and charges are as follows:

Tier 1:	0 kWh to 100 kWh	$10.50 per month
Tier 2:	101 kWh to 700 kWh	$11.75 per month
Tier 3:	701 kWh to 2,000 kWh	$17.50 per month
Tier 4:	kWh in excess of 2,000	$26.00 per month

Q. How were the tiers' ranges determined?

A. The tiers' ranges were determined based upon an analysis similar to the analysis performed for customers on Rate A-16 using load research and billing system data for customers on Rate C-06. The proposed customer charge for the initial tier is less than the customer-related cost of service unit charge of $11.08 per month, as shown on Schedule NG-11, line 25 for Rate C-06; therefore, the Company is proposing that the initial tier be limited to customers with maximum use equal to or less than 100 kWh to limit the number of customers being subsidized. Analysis of the Company's billing data indicates that less than 15 percent of small C&I customers have a monthly maximum use within that range.

Approximately 35 percent of the small C&I customers will fall into the second tier, with approximately 25 percent of the remaining customers assigned to the each of the two upper tiers.

Q. How were the customer charges for each tier level determined?

A. The initial tier's customer charge is set at $10.50 per month which is an increase of $0.50 per month from Rate C-06's current customer charge. The customer charges for the second, third, and fourth tiers are designed to recover the customer-related cost of service costs plus approximately 15 percent of the total demand-related costs, subject to the limits imposed by bill impact criteria.

Q. Please describe the design of the proposed energy-based rate for Rate C-06.

A. The next step is to design the per kWh charge which is the rate necessary to produce the rate class's revenue requirement as shown on Schedule NG-12, Page 2.

In total, approximately 40 percent of the Rate C-06 revenue requirement is designed to be recovered through the four customer charges, as compared to 24 percent based upon the current design.

Q. Please discuss the nature of service and the current rate design for Rate G-02.

A. Rate G-02 is available for all purposes to small and medium C&I customers. Rate G-02 customers must have demand of 10 kW or more, and the Company may require customers with 12-month average demand exceeding 200 kW to take service on Rate G-32. The current distribution rate structure for Rate G-02 includes a monthly customer charge, a per kWh charge, and a demand charge. The customer charge is designed to recover the customer-related costs, plus the cost associated with the first 10 kW of demand. The demand charge is assessed on demand in excess of 10 kW per month. Some customers receive discounts for taking service at higher voltages.

Q. What are the proposed rates for Rate G-02?

A. The Company is proposing to decrease the customer charge from its current level of $135.00 per month (i.e., customer-related revenue requirement plus demand revenue requirement associated with the first 10 kW of demand) to $75.00, which is closer to the cost of service customer-related unit cost than the current charge.

The next step is to design the per kWh charge and the demand (per kW) charge. The Company is proposing an increase in the demand charge from its current level of $4.85

per kW-month to $5.60 per kW-month. In addition, the Company is proposing to assess the demand charge on all kW, rather than kW in excess of 10 kW.

Q. Why is the Company proposing to change the way the demand charge is assessed?

A. The design of the current customer charge ensures that every month, at a minimum, the cost associated with 10 kW of demand is recovered from each customer. While this is an appropriate design for this class, since the rate is designed for customers with demand in excess of 10 kW, the Company is proposing this change in design to help mitigate the impact of increasing the per-kW charge on smaller customers in this rate class.

Q. How is the Rate G-02 per-kWh charge determined?

A. After determining the customer charge and the demand charge, the per kWh charge is computed as the rate needed to produce the proposed revenue for Rate G-02, after giving effect to customer charge revenue, demand charge revenue, High Voltage Delivery Discounts, and High Voltage Metering Discounts. The High Voltage Delivery Discount is for customers supplied at not less than 2,400 volts and not needing a line transformer, and is set at its current level of $0.42 per kW. The High Voltage Metering Discount is a percentage of amounts billed and, therefore, revenue.

The calculation of the proposed charges for Rate G-02 is presented on Schedule NG-12, Page 3.

Q. What percentage of Rate G-02 revenue will be recovered through the proposed customer and demand charges?

A. The proposed customer and demand charges increase in the percentage of revenue requirement recovered through fixed charges (i.e., customer and demand (per kW) charges)) to 90 percent from 84 percent.

Q. Please discuss the nature of service and the current rate design for Rate G-32 and Rate G-62.

A. The Company requires any customer with a maximum 12-month average demand of 200 kW or greater for three consecutive months to be on Rate G-32. The current Rate G-32 distribution rates include a monthly customer charge, a per kWh charge, and a demand charge for kW in excess of 200 kW. The customer charge is designed to recover the customer-related costs, plus the cost associated with the first 200 kW of demand. Some customers receive discounts for taking service at higher voltages.

Customers with maximum 12-month average demand in excess of 5,000 kW may take service on Rate G-62, at their option. The current Rate G-62 distribution rates include a monthly customer charge and a demand charge.

Customers receiving service on Rates G-32 or G-62 receive discounts for taking service at higher voltages. Both rates contain a provision for second feeder service.

Rates G-32 and G-62 have “companion” back-up service rates, Rates B-32 and B-62, respectively, for customers who provide some or all of their electricity from their own generation source, but require firm back-up service from the Company. Rates for back-up service are designed in conjunction with their full service counterparts.

Q. You stated earlier in your testimony that the Company is proposing to consolidate Rate G-32 and Rate G-62. Please describe the Company’s proposal to consolidate these two rate classes.

A. The Company is proposing to consolidate Rate G-32 and Rate G-62 into one set of rates applicable to all customers in both rate classes by combining the revenue requirements and billing units of the separate classes. The combined rate class will continue to be designated as Large Demand Rate G-32.

Q. Why is the Company proposing to consolidate Rate G-32 and Rate G-62 into a single rate class?

A. The Company is proposing to combine Rates G-32 and G-62 into one large C&I rate class based on the observation that the average per-unit demand-related cost to serve each class as determined in the ACOSS is nearly identical. Therefore, there is no compelling reason, based on cost causation principles, to maintain two separate classes. There are currently only nine customers receiving service on Rate G-62 and, of those nine, only five meet the current availability criteria for Rate G-62 based upon their size.

Q. What are the proposed rates for the consolidated Rate G-32/G-62?

A. The Company is proposing to decrease the customer charge from its current level of $825.00 per month (i.e., customer and the first 200 kW of demand) for Rate G-32 and $17,000.00 for Rate G-62 to $215.00, which is close to the weighted average of the customer-related unit costs for both rate classes. The next step is to design the per kWh charge and the demand charge. The Company is proposing a demand charge of $4.50 per kW-month. This represents an increase from the current demand charges of $3.70 per kW-month and $2.99 per-kW month for Rates G-32 and G-62, respectively. In addition, the Company is proposing to assess the demand charge on all kW, rather than kW in excess of 200 kW (applies to current Rate G-32 only).

Q. How is the proposed Rate G-32 per-kWh charge determined?

A. After determining the customer charge and demand charge, the per kWh charge is computed as the rate needed to produce the combined rate class's revenue requirement after giving effect to customer charge revenue, demand charge revenue, High Voltage Delivery Discounts, and High Voltage Metering Discounts. The calculation of the proposed per kWh charge for Rate G-32 is presented on Schedule NG-12, Page 4.

Q. What percentage of Rate G-32 revenue will be recovered through the proposed customer and demand charges?

A. The proposed customer and demand charges increase the percentage of revenue requirement that is recovered through the customer and demand (per kW) charges to 86 percent from 73 percent.

Q. Is the Company proposing any changes to the structure of the Back-up Service rates?

A. With the consolidation of Rate G-32 and Rate G-62, the Company is proposing to eliminate Rate B-62. The Company is not proposing any changes to the operation of Back-up Service Rate B-32; however, since the Supplemental and Back-up Demand charges are designed in conjunction with the rates for Rate G-32, these charges applicable to Rate B-32 customers will also change.

XI. <u>Proposed Distribution Rate for Stand-Alone Generators</u>

Q. What is the Company's proposal for the proper distribution rate for stand-alone generators?

A. The Company is proposing to implement an Access Fee applicable to stand-alone generators (i.e., DG facilities that are directly connected to the distribution system and have no associated on-site load), for any DG facility enrolled in any of the DG programs (i.e., Qualifying Facilities, net-metered facilities, RE Growth Program projects, and DG Standard Contract projects) as well as any new programs approved in the future by the

State. The Access Fee will be based upon the nameplate capacity of the DG facility, adjusted for expected availability capacity, and will be a fixed amount each month. Each DG facility will be required to sign an Access Service Agreement with the Company that will specify the nameplate capacity of the unit, the availability capacity factor that will determine the needed distribution system capacity, and the monthly Access Fee.

The Company is proposing to include the Access Fee requirement in both its Net Metering Provision, RIPUC No. 2150 and the Renewable Energy Growth Program for Non-Residential Customers, RIPUC No. 2152, and has revised both tariffs accordingly. Clean and marked to show changes versions of these tariffs, plus a proposed Access Service Agreement, are included in Schedules NG-14 and NG-15.

Q. What specifically is the Company proposing?

A. The Company is proposing, based on the voltage level at which a stand-alone DG facility is connected (primary or secondary), an Access Fee per kW-month based on the demand-related cost of service unit charge. The Access Fees are as follows:

Primary Voltage Level Fee:	$5.00 per kW-month
Secondary Voltage Level Fee:	$7.25 per kW-month

Each customer's executed Access Service Agreement will specify the customer's monthly demand which will be calculated as the nameplate capacity of the generating unit multiplied by the applicable availability capacity factors specific to the technology and operating characteristics of the generating facility.

The solar availability capacity factor is based on the recent "Final PV Forecast" as presented at the February 15, 2015 ISO-NE DG working group meeting (http://www.iso-ne.com/static-assets/documents/2015/05/final_2015_pv_forecast.pdf). The availability capacity factors for wind, anaerobic digestion, and hydro are still to be determined through further analytics and will be provided in a revised Access Service Agreement at a later date.

Q. How are stand-alone DG facilities which qualify for net metering currently billed?

A. Each stand-alone net metered DG facility is assigned a billing account for retail delivery service. Typically, the billing rate class assigned to the account is Rate C-06. The assignment of a rate class is generally based upon the expected delivered energy to the location. Since a stand-alone DG facility generally has only parasitic load,[16] the account is eligible for Rate C-06, which is generally available to customers with a monthly demand of less than 10 kW. As a Rate C-06 customer with only parasitic load, a stand-alone DG facility is billed only a monthly customer charge of $10.00 for distribution service, plus associated taxes. This current method of billing stand-alone DG facilities

[16] Parasitic load, also referred to as station service load, is energy used to operate auxiliary equipment and other load that is directly related to the production of energy by a DG facility.

does not provide adequate contribution towards recovery of the costs that the DG facility's use of the system causes the Company to incur to serve these customers.

Q. Why does the current method of billing stand-alone DG facilities not provide adequate cost recovery commensurate with the cost responsibility of the stand-alone DG facility?

A. It is important to understand that customer demand can be either the result of the customer's load, represented by inflow kW (a customer taking energy from the distribution system), or generation, represented by outflow kW (a customer needing the distribution system to facilitate the amount of DG on-site, or that exports energy to the system which exceeds the customer's on-site electric usage). In either case, the distribution system must be sized to accommodate that maximum demand imposed on it from either inflow or outflow kW. Therefore, proper cost allocation and cost recovery should recognize demand that results from either inflows or outflows of energy. This provision allowing an Access Fee would contribute towards the support for the distribution system that the DG facility relies upon for the movement of generated energy from the site of generation to other locations, as well as contributing towards the recovery of ongoing operation, maintenance and replacement costs of interconnection equipment.

In addition, the current use of Rate C-06 for these large projects does not compensate the Company for the cost of the interval metering required for these DG facilities to settle the corresponding generation asset at the Independent System Operator, New England (ISO-NE). The various statutes relating to DG require that a generation asset be set up at ISO-NE to use the wholesale revenue earned to offset the actual payments made to DG customers under any of the various DG programs in the state. The typical meter installation for a customer on Rate C-06 is a simple watt-hour meter, and the Rate C-06 customer charge reflects the cost of this type of meter. However, ISO-NE reporting requires the installation of a more complex and expensive interval meter that is typically only installed on larger C&I customers. Therefore, the cost of the more expensive interval meter is not fully recovered from a customer billed on Rate C-06. In addition, the management of DG on the distribution system requires changes to the Company's dispatching requirements, coordination with the ISO-NE, outage and maintenance scheduling, as well as planning of the system. The advent of allowing net metered customers to allocate excess credits to other accounts also causes changes in our customer service and billing needs.

Q. Why aren't these stand-alone DG facilities billed on a rate schedule more appropriate for their size?

A. The current practice is that the Company classifies the account of a DG facility based upon the on-site use at the service location, similar to the Company's practice of assigning other customers to the appropriate rate class. For stand-alone DG, this results in these installations being placed on Rate C-06. The Company is of the opinion that it has flexibility with this rate class assignment. In addition, there is little on-site use, and therefore the DG facility's use would not qualify it for a demand-based rate schedule. While an optimum solution would be to measure the DG facility's maximum use of the system, as measured by the energy generated and exported onto the distribution system, none of the Company's tariffs provides for such an application and measurement and billing of demand based on electricity exported onto the distribution system. The Company's proposal is intended to generate a monthly fixed fee for the use of the Company's distribution system beyond the DG facility's interconnection with the system.

Q. How is this proposal considered revenue neutral as required by the Act?

A. As part of this proposal, the Company will credit any revenue billed through this Access Fee to its Revenue Decoupling Mechanism (RDM) reconciliation, which is designed to capture all revenue billed and categorized as distribution revenue. Therefore, customers, in this case stand-alone DG customers, are contributing a reasonable share of revenue for the use of the system that is reflected in the distribution rates of all other customers, and through the RDM reconciliation, that revenue will be credited to customers and reflected in a lower RDM Adjustment Factor. Therefore, the Company will not realize incremental revenue from this proposal, but the stand-alone DG facility will pay for its use of the system that all other customers have been funding.

Q. Will the revenue generated by the Access Fee be included in the determination of the construction advance associated with the interconnection of new DG facilities to the Company's distribution system?

A. No, not at this time. The Access Fee is intended to result in the stand-alone DG facility paying a share of all other distribution system costs beyond the interconnection with the distribution system. Therefore, a revenue credit in determining the construction advance for interconnection costs would not be appropriate. In addition, pursuant to the Act, all of the Company's proposals in this filing are to be revenue neutral. If the Company were to begin to provide a revenue credit such that the interconnecting customer no longer reimburses the Company for 100 percent of its interconnection costs, then the capital investment that is not reimbursed at 100 percent will be recovered through the Company's Infrastructure, Safety, and Reliability Plan mechanism, which will generate incremental revenue.

XII. <u>Typical Bills and Individual Customer Bill Impacts</u>

Q. Has the Company included bill impacts in its filing?

A. Yes, it has. Schedule NG-13 represents a typical bill analysis demonstrating the total bill impacts of the proposed rates for customers who are receiving Standard Offer Service. The typical bill impact schedules for Rates A-16 (page 1) and C-06 (page 2) reflect the proposed tiered customer charge structure. For these two rate classes, the proposed distribution charges will be based upon both the customer's use in the current month, and the customer's monthly maximum use over the prior 12 months. The customer charge is determined based upon the Maximum Monthly kWh use ranges indicated. All kWh charges are applied to the current monthly use shown in the first column labeled Average Monthly kWh. The bill impact, both the dollar amount and the percentage of total bill, are shown in the section labeled Increase (Decrease). In addition, the last two columns of the table indicate the percentage of total customers in the class that fall into each of the usage levels indicated based upon the actual customer monthly bills for the 12-month period ending May 2015. As demonstrated by the analysis for Rate A-16, shown on page 1 of 17, and the similar analysis for Rate C-06, shown on page 2 of 17, the Company's proposed rates will limit the total bill impacts to +/- five percent for these two classes. As a result of the rates proposed in the Company's filing, a residential customer with an average monthly use of 500 kWh and a 12-month monthly maximum use of 250 kWh to 750 kWh will see a bill decrease of $1.77, or 1.8 percent, from $99.02 to $97.25. A customer with an average monthly use of 500 kWh and a 12-month monthly maximum use of 751 kWh to 1,200 kWh will see a bill increase of $2.92, or 2.9 percent, from $99.02 to $101.94. In addition to the typical bill analysis, the Company has prepared individual customer bill analyses for Rate G-02 and Rate G-32 based upon actual customer billing information. This analysis is included in Schedule NG-14.

XIII. Proposed Retail Delivery Service Tariffs and Tariff Provisions

Q. Has the Company included proposed tariffs and tariff provisions associated with its filing?

A. Yes it has. Schedules NG-15 and NG-16 contain the proposed tariffs and tariff provisions necessary to implement the Company's proposals in this filing. Schedule NG-13 contains a clean version of the tariffs reflecting all of the Company's proposed changes. Schedule NG-15 contains documents that are marked to show changes from those currently in effect.

The Company is not including RIPUC No. 2095, Summary of Retail Delivery rates, at this time. Since the proposed rates are not expected to be effective prior to April 1, 2016, the Company will file RIPUC No. 2095 in a compliance filing following PUC approval of new rates in this docket.

Q. Please describe the proposed tariff changes you are proposing.

A. The retail delivery tariffs, RIPUC Nos. 2100 (Basic Residential Rate A-16) and 2104 (Small C&I Rate C-06), have been revised to reflect the tiered customer charge rate structure described earlier in the testimony. RIPUC No. 2137 (Large Demand Back-up Service Rate) has been revised to indicate that demand charges will be calculated on all kW, rather than the first 200 kW per month. In addition, Optional Large Demand Rate

G-62, RIPUC No. 2141, and Optional Large Back-up Service Rate B-62, RIPUC No. 2138, are withdrawn in their entirety.

As indicated earlier in the testimony, the Company is requesting recovery of the billing system modifications and customer outreach and education costs associated with the changes proposed in this proceeding. RIPUC No. 2153, Renewable Energy Growth Program Cost Recovery Provision, has been revised to reflect recovery of those costs.

Finally, as indicated above, the Company is proposing revisions to the Net Metering Provision, RIPUC No. 2150 and the Renewable Energy Growth Program for Non-Residential Customers, RIPUC No. 2152 to reflect the inclusion of an Access Fee applicable to stand-alone generators.

XIV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

Glossary

Glossary

ACOSS (Allocated Cost of Service Study)	The purpose of an ACOSS is to apportion fairly a utility's total revenue requirement, including plant and other investments, operating expenses, depreciation, and taxes among the rate classes served by the utility. The ACOSS produces a revenue amount for each rate class, equal to the revenue that needs to be collected from that class to produce the system average rate of return on rate base.
base rates	Typically, rates that are determined as part of a general rate case and which, once determined, are fixed until a subsequent rate case. For National Grid, base rates are the rates that recover the costs of the distribution system at a specific point in time; therefore, base rates and distribution rates are sometimes used interchangeably.
billing unit	The measurement upon which a price is assessed. Billing units may be in the form of kilowatts (kW), kilowatt-hours (kWh) or number of customers per month, for example.
C&I customers	Commercial and Industrial customers
capacity or demand-related costs	Capacity-related costs are associated with utility plant that is designed, constructed, and operated to meet the demands of using the system; typically measured at a system peak demand or non-coincident class peak demand.
CHP	Combined Heat and Power
consumption or use	Use of energy as a source of heat or power, measured over a period of time, typically a billing month.
commodity (or supply) charges	Rates or charges designed to recover the costs of electricity supply procured pursuant to the Standard Offer Service Procurement Plan. Also includes all reconciliation factors related to the provision of supply such as the Standard Offer Service Cost Adjustment, the Standard Offer Administrative Cost Adjustment and the Renewable Energy Standard Charge.
customer charge	The fixed monthly fee that is intended to recover customer-related costs.

customer-related costs	Customer-related costs are incurred to connect a customer to the distribution system (usually called a service drop in the simplest situation), to meter the customer's usage (the cost of the meter itself, the cost to read the meter, and the cost to bill the usage read from the meter), and to maintain both customer-related distribution assets and the customer's account (the cost of providing customer service and customer accounting). Customer-related costs are primarily a function of the number of customers served, and they continue to be incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile.
delivery service charges	Rates or charges, other than base distribution rates, designed to recover non-commodity (Standard Offer Service) costs.
demand	Rate at which electricity is being used at a point in time, generally measured in 15, 30 or 60-minute intervals.
demand-based rates	Rates structured to include a demand or per kW charge.
demand charge	A demand charge recovers the demand, or capacity, related to system costs. The demand charge is assessed on a measurement of customer size, such as maximum connected load or maximum demand during a 15-minute interval, and would reflect the customer's relative contribution to system cost relative to other customers' demand.
DemandLink Pilot	Since 2012, National Grid has been conducting a system reliability plan pilot called "DemandLink" in Tiverton and Little Compton. This pilot is designed to defer the need for a new substation feeder in the Tiverton/Little Compton region through at least 2017 by targeting energy efficiency measures and conducting a demand response program in the area that will reduce the load on specific feeders attributable to customer air conditioning, lighting, and other summer-peaking loads.
demand meter	A demand meter measures the maximum electricity used at a point in time over a period of time, such as a billing month, rather than measuring the overall amount of electricity used.
DG (Distributed Generation)	Small scale generating technologies (e.g., solar, wind, combined heat and power, hydro or newer technologies) that are connected to the electric power grid are identified as DG. DG systems allow customers to produce some or all of the electricity they need. The electricity a customer uses (e.g., for heating ventilation, air conditioning, consumer electronics, lights) represents their electric load. By generating a portion or all of the electricity a customer uses, the customer can effectively reduce their electric load.

distributed energy resources	Smaller power sources that can be aggregated to provide power necessary to meet regular demand.
diversity of demand	Customer maximum demands which occur at different points in time throughout the day and the year relative to the aggregate maximum demand of all customers at a single point in time.
electric distribution grid	The final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. Distribution substations connect to the transmission system and lower the transmission voltage to medium voltage ranging between 2 kV and 35 kV with the use of transformers. Primary distribution lines carry this medium voltage power to distribution transformers located near the customer's premises. Distribution transformers again lower the voltage to the utilization voltage of household appliances and typically feed several customers through secondary distribution lines at this voltage. Commercial and residential customers are connected to the secondary distribution lines through service drops. Customers demanding a much larger amount of power may be connected directly to the primary distribution level or the sub-transmission level.
EPRI	Electric Power Research Institute
grid modernization	Our current electric grid uses many technologies that date back to the time of Thomas Edison, requiring the electricity industry to seek new ways in which power can be generated, delivered and used in ways that minimize environmental impacts, enhance markets, improve reliability and service, reduce costs and improve efficiency. Utilities are beginning to modernize the electric grid through the gradual development of a “smart grid” that uses information and communication technologies to manage electricity more efficiently. (EPRI definition)
islanding	Islanding occurs when a DG facility continues to operate, providing energy to a specific location even though electrical energy from the utility is no longer present.
kVa (kilovolt-amperes)	kilovolt-ampere is a unit of electrical power equal to 1000 volt-amperes

kWh (kilowatt-hour)	The kilowatt hour is a unit of energy equal to 1,000 watt-hours. If the energy is being transmitted or used at a constant rate (power) over a period of time, the total energy in kilowatt-hours is the product of the power in kilowatts and the time in hours. The kilowatt-hour is commonly used as a billing unit for energy delivered to consumers by electric utilities.
kW (kilowatt)	One kilowatt (kW) is equal to 1000 watts (W): 1kW = 1000W.
line transformer	A device transferring an alternating current from one circuit to another.
load	In general terms, the load is an electrical component that is connected to and draws power from an electric circuit.
load data	Metered data, typically in 15-minute or hourly intervals, that allows for the estimation of peak (or maximum) use of the distribution system at a given point in time
microgrids	Microgrids, which are localized grids that can disconnect from the traditional grid to operate autonomously and help mitigate grid disturbances to strengthen grid resilience, can play an important role in transforming the nation's electric grid. Microgrids can strengthen grid resilience and help mitigate grid disturbances because they are able to continue operating while the main grid is down, and they can function as a grid resource for faster system response and recovery. U.S. Department of Energy(energy.gov)
NCP	non-coincident peaks
net metering	A system in which solar panels or other renewable energy generators are connected to a public-utility power grid and surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from the utility.
rate class	Customers with similar usage characteristics that are grouped together for purposes of cost allocation and rate design.
rate structure	Refers to the type of rates, or charges, applicable to a given class or group or customers, such as per month, per kW or per kWh.
RE Growth	Renewable Energy Growth
revenue requirement	The utility's revenue requirement represents the total amount of money a utility must collect from customers to pay all costs including a reasonable return on investment. http://www.naruc.org/international/Documents/Calculating%20Revenue%20Requirement_Davis.pdf

Glossary

solar PV	Solar photovoltaic
stand-alone generation	Distributed generation facilities that are directly connected to the distribution system and have no associated on-site load.
storage technologies	Energy storage is accomplished by devices or physical media that store energy to perform useful processes at a later time.
test year	The test year is a measure of the operations and investment in some specified 12-month period.

Schedules of
Peter Zschokke & Jeanne Lloyd

Index of Schedules

Index of Schedules

- Schedule NG-1 Summary of Proposed Electric Distribution Service Rates
- Schedule NG-2 Growth in Use of Solar PV in Massachusetts
- Schedule NG-3 Electric Power Research Institute's (EPRI) "The Integrated Grid: Realizing the Full Value From Central and Distributed Energy Resources" (the EPRI Paper)
- Schedule NG-4 U.S. PV Capacity as a Percentage of Total Capacity Compared With Germany at the Beginning of Its "Energy Transformation" (Figure 2 from the EPRI Paper)
- Schedule NG-5 Estimate of Installed DG in RI through 2020
- Schedule NG-6 Illustration of Customer Diversity
- Schedule NG-7 Relationship between Maximum Monthly kWh and Maximum kW
- Schedule NG-8 Typical Residential Monthly Bill by Component
- Schedule NG-9 Illustration of Customer Savings from Energy Efficiency
- Schedule NG-10 Results of ACOSS and Distribution Revenue [Schedule JAL-1]
- Schedule NG-11 ACOSS Unit Costs – Compliance Filing in Docket No. 4323
- Schedule NG-12 Proposed Rate Design
- Schedule NG-13 Typical Bills
- Schedule NG-14 Individual Customer Bill Impacts
- Schedule NG-15 Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions
- Schedule NG-16 Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions, Marked to Show Changes from Those Currently in Effect

Schedule NG-1

Schedule NG - 1

Summary of Proposed Electric Distribution Service Rates

The Narragansett Electric Company
Summary of Proposed Electric Service Rates

Line		A-16	A-60	C-06	G-02	B-32 / G-32
		(a)	(b)	(c)	(d)	(e)
1	Customer Charges (per month)					
2						
3	Customer Charge Tier 1	$5.25	$0.00	$10.50	$75.00	$215.00
4	Customer Charge Tier 2	$8.50		$11.75		
5	Customer Charge Tier 3	$13.00		$17.25		
6	Customer Charge Tier 4	$18.00		$26.00		
7	Unmetered Charge			$6.00		
8						
9	Distribution per kWh Charge					
10						
11	kWh Charge	$0.02625	$0.02317	$0.02624	$0.00287	$0.00230
12						
13	Distribution Demand Charges (per kW)					
14						
15	kW				$5.60	$4.50
16	Backup kW					$0.53
17						
18	Other Charges and Credits					
19						
20	Additional Minimum Charge (per kVA in excess of 25 kVA)			$1.85		
21	High Voltage Delivery Discount				($0.42)	($0.42)
22	High Voltage Metering Discount				-1.0%	-1.0%
23	Additional High Voltage Delivery Discount (115kV)					($2.75)
24	Second Feeder Service					$2.75
25	Second Feeder Service - Additional Transformer Charge					$0.42
26						
27						
28						
29						
30						
31						

32 Notes:
33 Line (3 - 7)
34 Column (a): Schedule NG-12, Page 1, Column (e) lines 6-9
35 Column (b): Schedule NG-12, Page 1, Column (e) line 13
36 Column (c): Schedule NG-12, Page 2, Column (e) lines 5-10
37 Column (d): Schedule NG-12, Page 3, Column (d) line 18
38 Column (e): Schedule NG-12, Page 4, Column (e) line 7
39 Line (11)
40 Column (a): Schedule NG-12, Page 1, Column (e) line 18
41 Column (b): Schedule NG-12, Page 1, Column (e) line 23
42 Column (c): Schedule NG-12, Page 2, Column (e) line 22
43 Column (d): Schedule NG-12, Page 3, Column (d) line 25
44 Column (e): Schedule NG-12, Page 4, Column (e) line 30
45 Line (15)
46 Column (d): Schedule NG-12, Page 3, Column (d) line 29
47 Column (e): Schedule NG-12, Page 4, Column (d) line 37

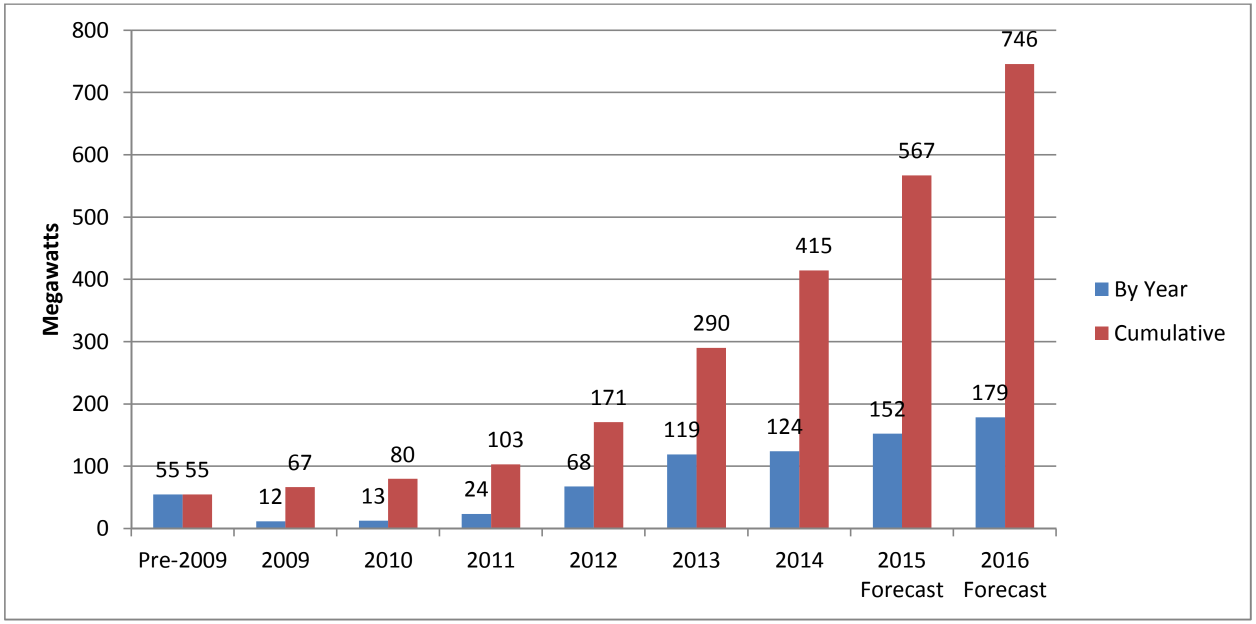
Line (16), Column (e): Schedule NG-12, Page 4, Column (d) line 35
Line (20), Column (c): Schedule NG-12, Page 2 Line (25)
Lines (20) through (25): per current tariff

Schedule NG-2

Schedule NG - 2

Growth in Use of Solar PV in Massachusetts

Growth in Use of Solar PV in Massachusetts



Actual (through June 2015) and estimated amount of DG to be installed in MA through 2016. As the net metering cap was met in April 2015, until any new programs are in place, estimates through 2020 are not possible

Schedule NG-3

Schedule NG - 3

Electric Power Research Institute's "The Integrated Grid: Realizing the Full Value From Central and Distributed Energy Resources" (the EPRI Paper)

THE INTEGRATED GRID

REALIZING THE FULL VALUE OF CENTRAL AND DISTRIBUTED ENERGY RESOURCES

Table of Contents

Executive Summary

The electric power system has evolved through large, central power plants interconnected via grids of transmission lines and distribution networks that feed power to customers. The system is beginning to change—rapidly in some areas—with the rise of distributed energy resources (DER) such as small natural gas–fueled generators, combined heat and power plants, electricity storage, and solar photovoltaics (PV) on rooftops and in larger arrays connected to the distribution system. In many settings DER already have an impact on the operation of the electric power grid. Through a combination of technological improvements, policy incentives, and consumer choices in technology and service, the role of DER is likely to become more important in the future.

The successful integration of DER depends on the existing electric power grid. That grid, especially its distribution systems, was not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. The technical characteristics of certain types of DER, such as variability and intermittency, are quite different from central power stations. To realize fully the value of distributed resources and to serve all consumers at established standards of quality and reliability, the need has arisen to integrate DER in the planning and operation of the electricity grid and to expand its scope to include DER operation—what EPRI is calling *the Integrated Grid*.

The grid is expected to change in different, perhaps fundamental ways, requiring careful assessment of the costs and opportunities of different technological and policy pathways. It also requires attention to the reality that the value of the grid may accrue to new stakeholders, including DER suppliers and customers.

This paper is the first phase in a larger Electric Power Research Institute (EPRI) project aimed at charting the transformation to the Integrated Grid. Also under consideration will be new business practices based on technologies, systems, and the potential for customers to become more active participants in the power system. Such information can support prudent, cost-effective investment in grid modernization and the integration of DER to enable energy efficiency, more responsive demand, and the management of variable generation such as wind and solar.[1]

Along with reinforcing and modernizing the grid, it will be essential to update interconnection rules and wholesale market and retail rate structures so that they adequately value both capacity and energy. Secure communications systems will be needed to connect DER and system operators. As distributed resources penetrate the power system more fully, a failure to plan for these needs could lead to higher costs and lower reliability.

Analysis of the Integrated Grid, as outlined here, should not favor any particular energy technology, power system configuration, or power market structure. Instead, it should make it possible for stakeholders to identify optimal architectures and the most promising configurations —recognizing that the best solutions vary with local circumstances, goals, and interconnections.

Because local circumstances differ, this paper illustrates how the issues that are central to the Integrated Grid are playing out in different power systems. For example, Germany's experience illustrates consequences for price, power quality, and reliability when the drive to achieve a high penetration of distributed wind and PV results in outcomes that were not fully anticipated. As a result, German policymakers and utilities now are changing interconnection rules, grid expansion plans, DER connectivity requirements, wind and PV incentives, and operations to integrate distributed resources.

In the United States, Hawaii has experienced a rapid deployment of distributed PV technology that is challenging the power system's reliability. In these and other jurisdictions, policymakers are considering how best to recover the costs of an integrated grid from all consumers that benefit from its value.

[1] *This paper is about DER, but the analysis is mindful of the ways that DER and grid integration could affect energy efficiency and demand response as those could have large effects as well on the affordability, reliability, and environmental cleanliness of the grid.*

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial character of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards
   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]

3. Strategies for Integrating DER with Grid Planning and Operation
   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, distribution system operators (DSOs), and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and independent system operators (ISOs)

4. Enabling Policy and Regulation
   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long-term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI and Industry

EPRI has begun work on a three-phase initiative to provide stakeholders with information and tools that will be integral to the four areas of collaboration outlined above:

- **Phase I** – A concept paper (this document) to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review were provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties.
- **Phase II** – This six-month project will develop a framework for assessing the costs and benefits of the combinations of technology that lead to a more integrated grid. This includes recommended guidelines, analytical tools, and procedures for demonstrating technologies and assessing their unique costs and benefits. Such a framework is required to ensure consistency in the comparison of options and to build a comprehensive set of data and information that will inform the Phase III demonstration program. Phase II output will also support policy and regulatory discussions that may enable integrated grid solutions.
- **Phase III** – Conduct global demonstrations and modeling using the analytics and procedures developed in Phase II to provide comprehensive data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Taken together, Phases II and III will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Additionally, interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and transmission system operators (TSOs) or ISOs will be developed. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective, prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

Key Points – The Integrated Grid

Several requirements are recognized when defining an integrated grid. It must enhance electrical infrastructure, must be universally applicable, and should remain robust under a range of foreseeable conditions:

- Consumers and investors of all sizes are installing DER with technical and economic attributes that differ radically from the central energy resources that have traditionally dominated the power system.
- So far, rapidly expanding deployments of DER are *connected* to the grid but not *integrated* into grid operations, which is a pattern that is unlikely to be sustainable.
- Electricity consumers and producers, even those that rely heavily on DER, derive significant value from their grid connection. Indeed, in nearly all settings the full value of DER requires grid connection to provide reliability, virtual storage, and access to upstream markets.
- DER and the grid are not competitors but complements, provided that grid technologies and practices develop with the expansion of DER.
- We estimate that the cost of providing grid services for customers with distributed energy systems is about $51/month on average in the typical current configuration of the grid in the United States; in residential PV systems, for example, providing that same service completely independent of the grid would be four to eight times more expensive.
- Increased adoption of distributed resources requires interconnection rules, communications technologies and standards, advanced distribution and reliability technologies, integration with grid planning, and enabling policy and regulation.
- Experience in Germany provides a useful case study regarding the potential consequences of adding extensive amounts of DER without appropriate collaboration, planning, and strategic development.
- While this report focuses on DER, a coherent strategy for building an integrated grid could address other challenges such as managing the intermittent and variable supply of power from utility-scale wind and solar generators.

Today's Power System

Today's power system was designed to connect a relatively small number of large generation plants with a large number of consumers. The U.S. power system, for example, is anchored by ~1,000 gigawatts (GW) of central generation on one end, and on the other end are consumers that generally do not produce or store energy [4] [5]. Interconnecting those is a backbone of high-voltage transmission and a medium- and low-voltage distribution system that reaches each consumer. Electricity flows in one direction, from power plants to substations to consumers, as shown in Figure 1. Even with increasing penetration, U.S. distributed resources account for a small percent of power production and consumption and have not yet fundamentally affected that one-way flow of power.

Energy, measured in kilowatt-hours (kWh), is delivered to consumers to meet the electricity consumption of their lighting, equipment, appliances, and other devices, often called *load*. *Capacity* is the maximum capability to supply and deliver a given level of energy at any point in time. *Supply capacity* comprises networks of generators designed to serve load as it varies from minimum to maximum values over minutes,

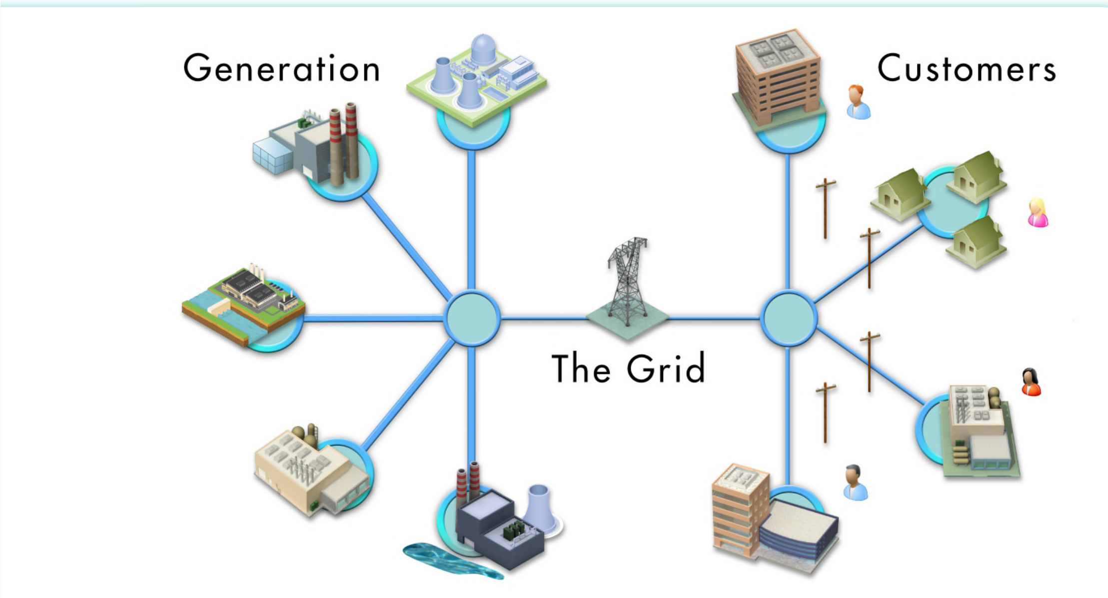


Figure 1: Today's Power System Characterized by Central Generation of Electricity, Transmission, and Distribution to End-Use Consumers.

hours, days, seasons, etc. *Delivery capacity* is determined by the design and operation of the power transmission and distribution systems that deliver the electricity to consumers. The system's supply and delivery capacity plan is designed to serve the expected instantaneous maximum demand over a long-term planning horizon.

Because the whole grid operates as a single system in real time and the lead times for building new resources are long, planning is essential to ensuring the grid's adequacy. Resource adequacy planning determines the installed capacity required to meet expected load with a prescribed reserve margin that considers potential planned and unplanned unavailability of given generators. In addition to providing sufficient megawatts to meet peak demand, the available generation (along with other system resources) must provide specific operating capabilities to ensure that the system operates securely at all times. These ancillary services include frequency regulation, voltage support, and load following/ramping. As a practical matter, the reliability of grid systems is highly sensitive to conditions of peak demand when all of these systems must operate in tandem and when reserve margins are smallest.

Today's power system has served society well, with average annual system reliability of 99.97% in the United States, in terms of electricity availability [6]. The National Academy of Engineering designated electrification enabled by the grid as the top engineering achievement of the twentieth century. Reliable electrification has been the backbone of innovation and growth of modern economies. It has a central role in many technologies considered pivotal for the future, such as the internet and advanced communications.

Today's power system has served society well, with average annual system reliability of 99.97% in the U.S., in terms of electricity availability.

The Growth in Deployment of Distributed Energy Resources

The classic vision of electric power grids with one-way flow may now be changing. Consumers, energy suppliers, and developers increasingly are adopting DER to supplement or supplant grid-provided electricity. This is particularly notable with respect to distributed PV power generation—for example, solar panels on homes and stores—which has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013 [7]. In Germany, the present capacity of solar generation is approximately 36 GW, while the daily system peak demand ranges from about 40 to 80 GW. By the end of 2012, Germany's PV capacity was spread across approximately 1.3 million residences, businesses, and industries and exceeded the capacity of any other single power generation technology in the country [8]. This rapid spread of DER reflects a variety of public and political pressures along with important changes in technology. This paper focuses on system operation impacts as DER reaches large scales.

By the end of 2013, U.S. PV installations had grown to nearly 10 GW. Although parts of the U.S. have higher regional penetration of PV, this 10 GW represents less than 2% of total installed U.S. generation capacity [9], which matches German PV penetration in 2003 (Figure 2). With PV growth projected to increase in scale and pace over the next decade, now is the time to consider lessons from Germany and other areas with high penetration of distributed resources.

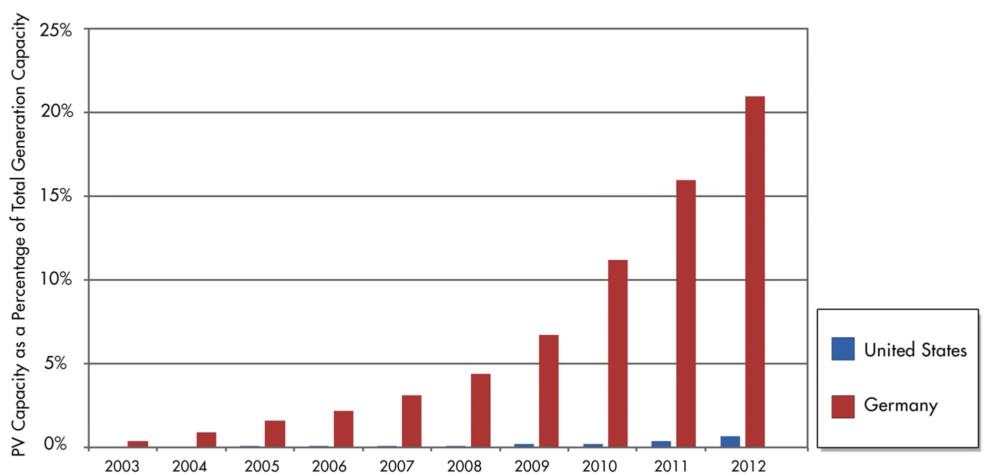


Figure 2: U.S. PV Capacity as a Percentage of Total Capacity Compared with Germany at the Beginning of Its "Energy Transformation."

In addition to Germany, high penetration of distributed PV is evident in California, Arizona, and Hawaii and in countries such as Italy, Spain, Japan, and Australia [7]. Beyond PV, other distributed resources are expanding and include such diverse technologies as batteries for energy storage, gas-fired micro-generators, and combined heat and power (CHP) installations—often referred to as *cogeneration*. In the United States natural gas prices and the cost and efficiency of gas-fired technologies have made these options effectively competitive with retail electricity service in some regions, for some consumers [10]. In jurisdictions where power prices are high, even more costly DER such as solar PV can be competitive with grid-supplied power.

In most cases, grid-connected DER benefit from the electrical support, flexibility, and reliability that the grid provides, but they are not integrated with the grid's operation. Consequently, the full value of DER is not realized with respect to providing support for grid reliability, voltage, frequency, and reactive power.

Distributed PV power generation has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013.

Germany's Experience: More Distributed but Not Integrated

The circumstances surrounding Germany's extensive deployment of distributed solar PV and wind offers important lessons about the value of planning for integration of DER, both economic and technical. Germany's experience is unique for these reasons:

- Germany represents a large interconnected grid with extensive ties with other grids, which is similar to the U.S. and other countries.
- The penetration of DER over the past decade is substantial (~68 GW of installed capacity of distributed PV and wind generation over 80 GW of peak load). The observed results, in terms of reliability, quality, and affordability of electricity, are not based on a hypothetical case or on modeling and simulations.
- This growth in penetration of DER occurred without considering the integration of these resources with the existing power system.
- Germany has learned from this experience, and the plan for continuing to increase the deployment of solar PV and wind generation hinges on many of the same integrated grid ideas as outlined in this paper.

German deployment was driven by policies for renewable generation that have commanded widespread political support. PV and wind generation are backed by the German Renewable Energy Sources Act (EEG), which stipulates feed-in tariffs[2] (FIT) for solar power installations. This incentive, which began in 2000 at €0.50/kWh ($0.70/kWh) for a period of 20 years, has stimulated major deployment of distributed renewable generation.

In the meantime, electricity rates have increased in Germany, for various reasons, to an average residential rate in 2012 of €0.30/kWh ($0.40/kWh), more than doubling residential rates since 2000 [8]. These higher electricity rates and lower costs for DER, due to technology advancements and production volume, have turned the tables in Germany. Today, the large FIT incentives are no longer needed, or offered, to promote new renewable installations.[3]

Notably, the desire to simultaneously contain rising electricity rates while promoting deployment of renewable energy resources has led to an evolution in German incentive policy for distributed renewable generation. For residential PV the FIT has dropped from ~ €0.50/kWh in 2000 to ~ €0.18/kWh today. An electricity price greater than the FIT has resulted in a trend of self-consumption of local generation. To ensure that all customers are paying for the subsidy for PV, the German cabinet in January 2014 approved a new charge on self-consumed solar power. Those using their own solar-generated electricity will be required to pay a €0.044kWh ($0.060/kWh) charge. Spain is considering similar rate structures to ensure that all customers equitably share the cost. Still to be resolved is how grid operating and infrastructure costs will be recovered from all customers who utilize the grid with increasing customer self-generation.

Technical repercussions have resulted from DER's much larger share of the power system. Loss of flexibility in the

[2] *Feed-in tariffs are a long-term guaranteed incentive to resource owners based on energy production (in kWh), which is separately metered from the customer's load.*

[3] *PV installations commissioned in July 2013 receive €0.104 to €0.151/kWh ($0.144 to $0.208/kWh) for a period of 20 years.*

generation fleet prompted the operation of coal plants on a "reliability-must-run" basis. Distributed PV was deployed with little time to plan for effective integration. Until the last few years and the advent of grid codes, PV generators were not required to respond to grid operating requirements or to be equipped to provide grid support functions, such as reactive power management or frequency control. Resources were located without attention to the grid's design and power flow limitations. The lack of coordination in planning and deploying DER increases the cost of infrastructure upgrades for all customers and does not provide the full value of DER to power system operation. Rapid deployments have led to several technical challenges:

1. Local over-voltage or loading issues on distribution feeders. Most PV installations in Germany (~80%) are connected to low-voltage circuits, where it is not uncommon for the PV capacity to exceed the peak load by three to four times on feeders not designed to accommodate PV. This can create voltage control problems and potential overloading of circuit components [11].
2. Risk of mass disconnection of anticipated PV generation in the event of a frequency variation stemming from improper interconnection rules.[4] This could result in system instability and load-shedding events [12]. The same risk also exists from both a physical or cyber security attack.
3. Resource variability and uncertainty have disrupted normal system planning, causing a notable increase in generation re-dispatch[5,6] events in 2011 and 2012 [13].
4. Lack of the stabilizing inertia from large rotating machines that are typical of central power stations[7] has raised general concern for maintaining the regulated frequency and voltage expected from consumers, as inverter-based generation does not provide the same inertial qualities [14].

---

[4] *Distributed PV in Germany initially was installed with inverters that are designed to disconnect the generation from the circuit in the event of frequency variations that exceed 50.2 Hz in their 50 Hz system. Retrofits necessary to mitigate this issue are ongoing and are estimated to cost approximately $300 million [12].*

[5] *German transmission system operator Tennett experienced a significant increase in generation re-dispatch events in 2011 and 2012 relative to previous years. Generation scheduling changes are required to alleviate power flow conditions on the grid or resource issues that arise on short notice rather than in the schedule for the day.*

[6] *While the primary driver to re-dispatch issues has been a reduced utilization of large nuclear generators, the increase in wind generation and PV in Germany is expected to continue changing power flow patterns.*

[7] *Many DER connect to the grid using inverters, rather than the traditional synchronous generators. Increasing the relative amount of distributed and bulk system inverter-based generation that displaces conventional generation will negatively impact system frequency performance, voltage control and dynamic behavior if the new resources do not provide compensation of the system voltage and frequency support.*

Smart inverters capable of responding to local conditions or requests from the system operator can help avoid distribution voltage issues and mass disconnection risk of DER. This type of inverter was not required by previous standards in Germany, although interconnection rules are changing to require deployment of smart inverters. (See the highlight box below for further information.)

The rate impacts and technical repercussions observed in Germany provide a useful case study of the high risks and unintended consequences resulting from driving too quickly to greater DER expansion without the required collaboration, planning, and strategies set forth in the Action Plan. The actions in Phases II and III should be undertaken as soon as it is feasible to ensure that systems in the United States and internationally are not subjected to similar unintended consequences that may negatively impact affordability, environmental sustainability, power quality, reliability, and resiliency in the electric power sector.

Smart Inverters and Controls

With the current design emphasis on distribution feeders supporting one-way power flow, the introduction of two-way power flow from distributed resources could adversely impact the distribution system. One concern is over-voltage, due to electrical characteristics of the grid near a distributed generator. This could limit generation on a distribution circuit, often referred to as *hosting capacity*. Advanced inverters, capable of responding to voltage issues as they arise, can increase hosting capacity with significantly reduced infrastructure costs [15], [16].

German Grid Codes

In Germany, grid support requirements are being updated so that distributed resources can be more effectively integrated with grid operation [17], [18]. These requirements, called *grid codes*, are developed in tandem with European interconnection requirements recommended by the European Network of Transmission System Operators (ENTSO-E) [19], [20]:

1. Frequency control is required of all generators, regardless of size. Instead of disconnecting when the frequency reaches 50.2 Hz, generator controls will be required to gradually reduce the generators' active power output in proportion to the frequency increase (Figure 3). Other important functions, such as low-voltage ride-through, are also required at medium voltage.

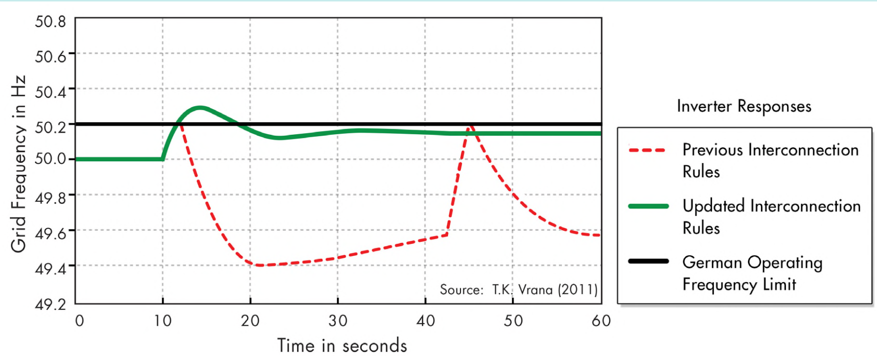


Figure 3: Example of Improved Performance with Inverter Controls That Implement a Droop Function for Over-Frequency Conditions Rather Than Tripping.

2. Voltage control functions are required from inverters, depending on the requirements of the DSO. Control methods include fixed power-factor operation, variable power factor as a function of active power, or reactive power management to provide voltage control.
3. Communication and energy management functions are now required of distributed resources, receiving commands from the system operator for active and reactive power management. As of 2012, this capability is required for all installations greater than 30 kVA. Systems less than 30 kVA without this capability are limited to 70% of rated output.

Germany is requiring that all existing inverters with a capacity greater than 3.68 kVA be retrofitted to include the droop function rather than instantly tripping with over-frequency. The cost of the retrofit associated with this function is estimated to be $300 million.

While necessary, these steps are probably still not enough to allow full integration of DER into the grid. Significant investment in the grid itself will be needed, including development of demand response resources (for example, electric transportation charging stations with time of use tariffs), and various energy storage systems. Also needed are markets and tariffs that value capacity and replacement of fossil-fueled heating plants with electric heating to take advantage of excess PV and wind capacity. German energy agency DENA determined that German distribution grids will require investment of €27.5 billion to €42.5 billion ($38.0 billion to $58.7 billion) by 2030. This includes expanding distribution circuits between 135,000 km and 193,000 km [21]. Extensive research is under way to develop and evaluate technologies to improve grid flexibility and efficiency with even more renewable capacity.

Assessing the Cost and Value of Grid Services

An electric grid connection, in ways different from a telephone line, provides unique and valuable services. Thirty percent of landline telephone consumers have canceled this service, relying solely on cellular service [22]. In contrast, virtually all consumers that install distributed generation remain connected to the grid. The difference is that the cellular telephone network provides functionality approximately equal to landline service, while a consumer with distributed generation will still need the grid to retain the same level of service. Unlike a cell phone user, operating without interconnection to this grid will require significant investment for on-site control, storage, and redundant generation capabilities.

This section characterizes the value of grid service to consumers with DER, along with calculations illustrating costs and benefits of grid connection. Subsequent sections focus on the value that DER can provide to the grid. In the context of value, it is important to distinguish the difference between value and cost. Value reflects the investments that provide services to consumers. It guides planning and investment decisions so that benefits equal or exceed costs. The costs that result are recovered through rates that, in a regulated environment, are set to recover costs, not to capture the full value delivered.

Value of Grid Service: Five Primary Benefits

Often, the full value of a grid connection is not fully understood. Grid-provided energy (kWh) offers clearly recognized value, but grid connectivity serves roles that are important beyond providing energy. Absent redundancy provided by the grid connection, the reliability and capability of the consumer's power system is diminished. Grid capacity provides needed power for overload capacity, may absorb energy during over-generation, and supports stable voltage and frequency. The primary benefits of grid connectivity to consumers with distributed generation are shown in Figure 4 and are described below.

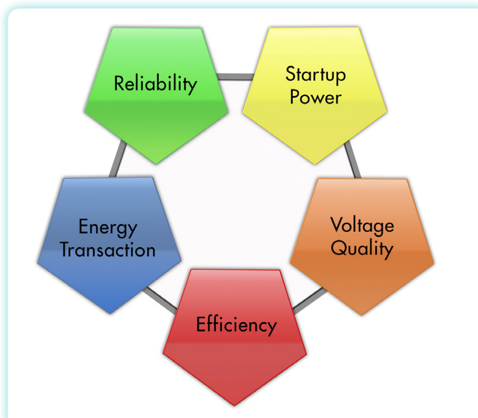


Figure 4: Primary Benefits of Grid Connectivity to Consumers with Distributed Generation.

1. **Reliability** – The grid serves as a reliable source of high-quality power in the event of disruptions to DER. This includes compensating for the variable output of PV and wind generation. In the case of PV, the variability is not only diurnal, but as shown in Figure 5, overcast conditions or fast-moving clouds can cause fluctuation of PV-produced electricity. The grid serves as a crucial balancing resource available for whatever period—from seconds to hours to days and seasons—to offset variable and uncertain output from distributed resources. Through instantaneously balancing supply and demand, the grid provides electricity at a consistent frequency. This balancing extends beyond real power, as the grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation.[8]

The need for reliability is fundamental to all DER, not just variable and intermittent renewable sources. For example, a customer depending solely on a gas-fired generator, which has an estimated reliability of 97%, is projected to experience 260 hours of power outage [23] compared with the 140 minutes of power outage that U.S. grid consumers experience on average (excluding major events such as hurricanes) [6]. Improvements in reliability are generally achieved through redundancy. With the grid, redundant capacity can be pooled among multiple consumers, rather than each customer having to provide its own backup resources. This reduces the overall cost of reliability for each customer [23].

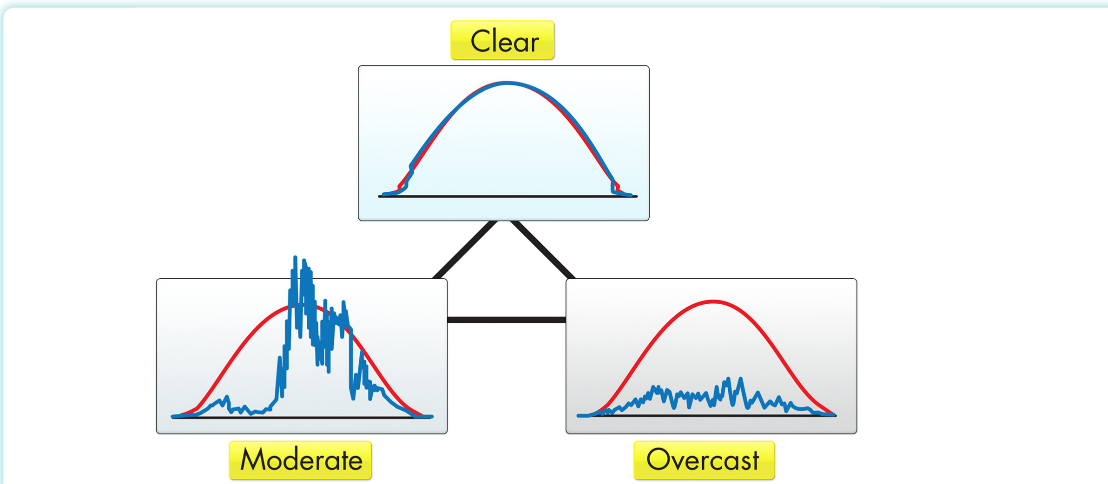


Figure 5: The Output of PV Is Highly Variable and Dependent on Local Weather.

[8] *Consumer loads typically require two different kinds of power, both real and reactive. Real power is a function of the load's energy consumption and is used to accomplish various tasks. Reactive power is transferred to the load during part of the cycle and returned during the other part, doing no work. Balancing both real and reactive power flow is a necessary function of a reliable electric grid.*

2. **Startup Power** – The grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current ("in-rush" current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without grid connectivity or other supporting technologies,[9] a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current. A system's ability to provide this current is directly proportional to the fault contribution level.[10] Even if a reciprocating engine distributed generator is used as support, its fault level is generally five times less than the grid's [23]. The sustained fault current from inverter-based distributed resources is limited to the inverter's maximum current and is an order of magnitude lower than the fault level of the grid.

Figure 6 illustrates the instantaneous power required to start a residential air conditioner. The peak current measured during this interval is six to eight times the standard operating current [24]. While the customer's PV array could satisfy the real power requirements of the heating, ventilating, and air conditioning (HVAC) unit during normal operation, the customer's grid connection supplies the majority of the required starting power.

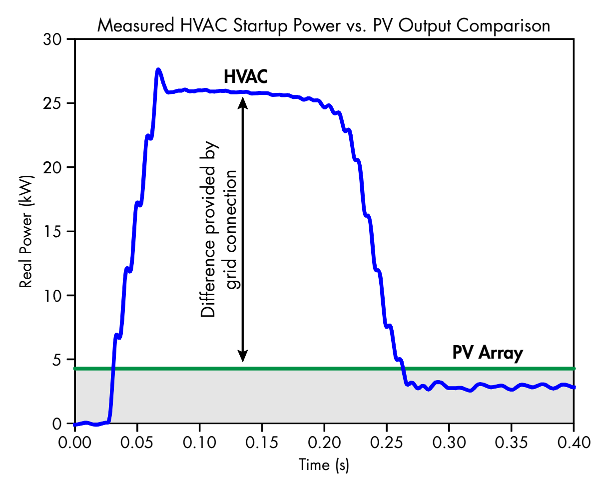


Figure 6: The Grid Provides In-Rush Current Support for Starting Large Motors, Which May Be Difficult to Replicate with a Distributed Generator.

[9] *Supporting technologies include variable-frequency drive (VFD) systems, which are able to start motors without the in-rush current common in "across-the-line" starting [24].*

[10] Fault level *is a measure of the current that would flow at a location in the event of short circuit. Typically used as a measure of electrical strength, locations with a high fault level are typically characterized by improved voltage regulation, in-rush current support, and reduced harmonic impact. Locations with a low fault level are more susceptible to voltage distortion and transients induced by harmonic-producing loads.*

3. **Voltage Quality** – The grid's high fault current level also results in higher quality voltage by limiting harmonic distortion[11] and regulating frequency in a very tight band, which is required for the operation of sensitive equipment. Similarly, the inherent inertia of a large connected system minimizes the impact of disturbances, such as the loss of a large generator or transmission line, on the system frequency. As shown in Figure 7, grid-connected consumers on average will experience voltage that closely approximates a sinusoidal waveform with very little harmonic distortion.

   In contrast, voltage from a distributed system that is not connected to the grid will generally have a higher voltage harmonic distortion, which can result in malfunction of sensitive consumer end-use devices. Harmonics cause heating in many components, affecting dielectric strength and reducing the life of equipment, such as appliances,[12] motors, or air conditioners [25]. Harmonics also contribute to losses that reduce system efficiency. In addition, a disturbance occurring inside the unconnected system will create larger deviations in frequency than if the system maintained its connection to the larger grid.

4. **Efficiency** – Grid connectivity enables rotating-engine-based generators to operate at optimum efficiency. Rotating-engine-based distributed resources, such as micro-turbines or CHP systems are most efficient when operating steadily near full output [26]. This type of efficiency curve is common for any rotating machine, just as automobiles achieve the best gasoline mileage when running at a steady optimal speed. With grid

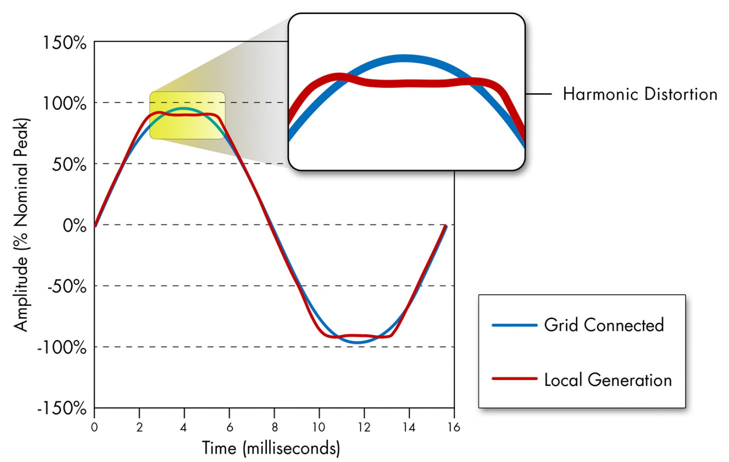


Figure 7: The Grid Delivers High-Quality Power with Minimal Harmonic Distortion.

[11] Harmonics *are voltages or currents that are on the grid, but do not oscillate with the main system frequency (60Hz in the United States). The magnitude of the harmonics, when compared to the magnitude of the 60Hz component, is referred to as the* harmonic distortion.

[12] *Technological improvements are available, such as uninterruptible power supplies (UPS), that reduce the sensitivity of loads to poor power quality, but at an additional cost.*

connectivity, a distributed energy resource can always run at its optimum level without having to adjust its output based on local load variation. Without grid connectivity, the output of a distributed energy resource will have to be designed to match the inherent variation of load demand. This fluctuating output could reduce system efficiency as much as 10%–20% [26].

5. **Energy Transaction** – Perhaps the most important value that grid connectivity provides consumers, especially those with distributed generation, is the ability to install any size DER that can be connected to the grid. A utility connection enables consumers to transact energy with the utility grid, getting energy when the customer needs it and sending energy back to the grid when the customer is producing more than is needed. This benefit, in effect, shifts risks with respect to the size of the energy resource from the individual user to the party responsible for the resources and operation of the grid. Simulated system results for such transactions are provided in Figure 8.

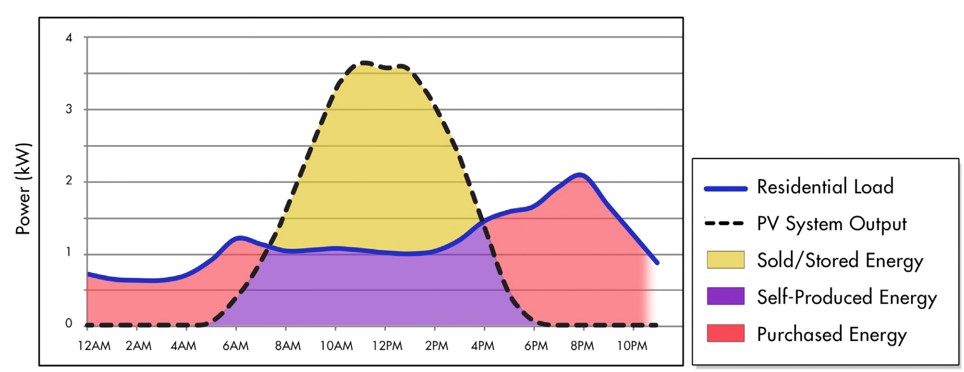


Figure 8: Because Residential Load and PV System Output Do Not Match, Owners of Distributed Generation Need the Grid for Purchasing or Selling Energy Most of the Time.

Cost of Grid Service: Energy and Capacity Costs

For residential customers, the cost for generation, transmission, and distribution components can be broken down as costs related to serve the customer with *energy* (kWh) and costs related to serve the customer with *capacity* that delivers the energy and grid-related services. The five main benefits of grid connectivity discussed in the previous section span both capacity and energy services. Figure 9 shows that, based on the U.S. Department of Energy's *Annual Energy Outlook 2012*, an average customer consumes 982 kWh per month, paying an average bill of $110 per month, with the average cost of $70 for generation of electricity. That leaves $30 for the distribution system and $10 for the transmission system [27]—known together as "T&D". These are average values, and costs vary among and within utilities and across different types of customers. (See *Appendix A* for explanation of calculations in this section.)

The next step in the analysis is to allocate these costs (generation and T&D) into fractions that are relevant for analyzing how the grid works with DER. In this analysis we focus on capacity and grid-related services because they are what enable robust service even for customers with DER. Indeed, consumers with distributed generation may not consume any net energy (kWh) from the grid, yet they benefit from the same grid services as consumers without distributed generation.

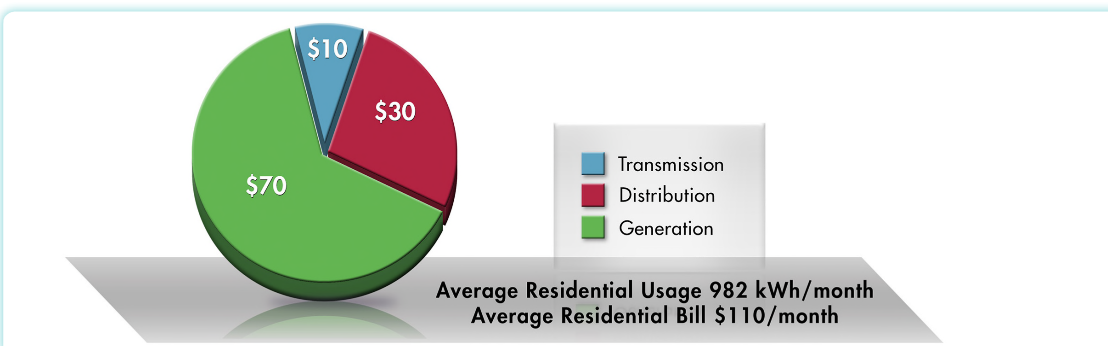


Figure 9: Cost of Service Breakdown for Today's Grid-Connected Residential Customer [27].

Calculating the total cost of capacity follows the analysis summarized in Figure 10. These values are based on the assumption that most costs associated with T&D are related to capacity (except for a small fraction representing system losses—estimated to be $3 per month per customer from recent studies in California) [28]. Working with recent data from PJM [29] regarding the cost of energy, capacity, and ancillary services it is possible to estimate that 80% of the cost of generation is energy related, leaving the rest for capacity and grid services. This 80-20 split will depend on the market and in the case of a vertically integrated utility will depend on the characteristics of the generation assets and load profile, but it is a useful average figure with which some illustrative calculations follow.

As illustrated, the combination of transmission, distribution, and the portion of generation that provides grid support averages $51/month, while energy costs average $59/month. These costs vary widely across the United States and among consumers and also will vary with changes in generation profile and the deployment of new technologies such as energy storage, demand response-supplied capacity, and central generation. The values are shown to illustrate that capacity and energy are both important elements of cost and should be recovered from all customers who use capacity and energy resources. Customers with distributed generation may offset the energy cost by producing their own energy, but as illustrated in previous sections, they still utilize the non-energy services that grid connectivity provides.

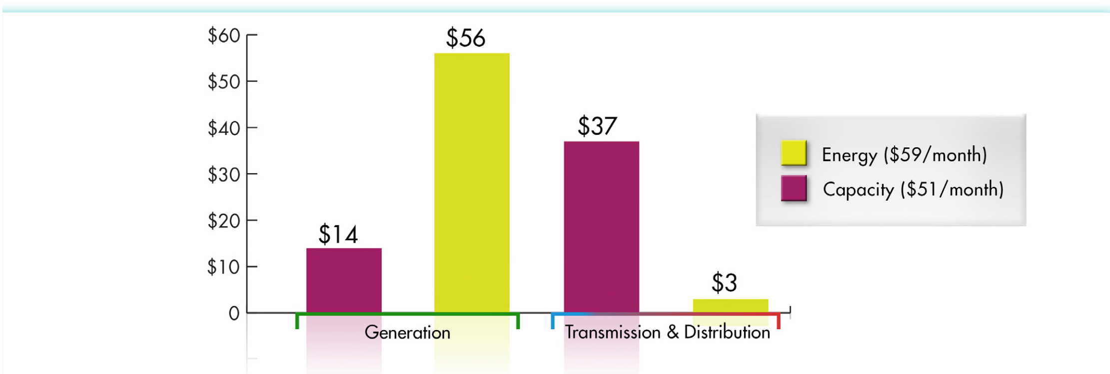


Figure 10: In Considering the Value of the Integrated Grid, Costs of Generation, Transmission, and Distribution Can Be Further Determined for Energy and Capacity.

Cost of Service Without Grid Connectivity

Technologies are available that enable consumers to self-generate and disconnect from the grid. To estimate the capacity-related cost for such investments, a simplified analysis examined a residential PV system. The analysis was based on estimating the additional costs of providing the five services that grids offer—as outlined earlier in this section. For illustration, consider a residential PV system that is completely disconnected from the grid, amortized over 20 years, and presented as a monthly cost. Reinforcing the system for an off-grid application required the following upgrades:

- Additional PV modules beyond the requirements for offsetting annual energy consumption in order to survive periods of poor weather
- Multi-day battery storage with a dedicated inverter capable of operating in an off-grid capacity
- Backup generator on the premises designed to operate for 100 hours per year
- Additional operating costs, including inverter replacement and generator maintenance

In simulation, the cost to re-create grid-level service without a grid connection ranges from \$275–\$430 per month *above* that of the original array. Expected decreases in the cost of battery and PV module technology could reduce this to \$165–\$262 within a decade. Further information on this analysis is provided in Appendix A. Costs for systems based on other technologies, or larger deployments such as campus-scale microgrids, could be relatively lower, based on economies of scale. However, even if amortized capital costs are comparable to grid services, such isolated grids will result in deteriorating standards of reliability and quality of electricity service and could require extensive use of backup generators whose emissions negatively impact local air quality.

Such isolated grids will result in deteriorating standards of reliability and quality of electricity service and could require extensive use of backup generators whose emissions negatively impact local air quality.

Enabling Policy and Regulation

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid. New market frameworks will have to evolve in assessing potential contributions of distributed and central resources to system capacity and energy costs. Such innovations will need to be anchored in principles of equitable cost allocation, cost-effective and socially beneficial investment, and service that provides universal access and avoidance of bypass.

As discussed, the cost of supply and delivery capacity can account for almost 50% of the overall cost of electricity for an average residential customer. Traditionally, residential rate structures are based on metered energy usage. With no separate charge for capacity costs, the energy charge has traditionally been set to recover both costs. This mixing of fixed and variable cost recovery is feasible when electricity is generated from central stations, delivered through a conventional T&D system, and used with an electromechanical meter that measures energy use only by a single entity [30] [31].

Most residential (and some commercial) rate designs follow this philosophy, but the philosophy has not been crisply articulated nor reliably implemented for DER. Consequently, consumers that use distributed resources to reduce their grid-provided energy consumption significantly but remain connected to the grid, may pay significantly less than the costs incurred by the utility to provide capacity and grid connectivity. In effect, the burden of paying for that capacity can potentially shift to consumers without DER [32].

A logical extension of the analysis provided here, as well as many other studies that look at DER under different circumstances, is that as DER deploy more widely, policy makers will need to look closely at clearly separating how customers pay for actual energy and how they pay for capacity and related grid services.

A policy and regulatory framework will be needed to encourage the effective, efficient, and equitable allocation and recovery of costs incurred to transform to an integrated grid.

Realizing the Value of DER Through Integration

The analysis of capacity-related costs (including the cost of ancillary services) in the previous sections is based on today's snapshot of the components that make up the grid and is also based on a minimum contribution from DER to reduce the capacity cost. With increasing penetration of variable generation (distributed and central), it is expected that capacity- and ancillary service-related costs will become an increasing portion of the overall cost of electricity [33].

However, with an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services that will be needed to operate the grid. The following considerations will affect whether and how DER contribute to system capacity needs:

- Delivery Capacity – The extent to which DER reduce system delivery capacity depends on the expected output during peak loading of the local distribution feeder, which typically varies from the aggregate system peak. If feeder peak demand occurs after sunset, as is the case with many residential feeders, local PV output can do nothing to reduce feeder capacity requirements. However, when coupled with energy storage resources dedicated to smoothing the intermittent nature of the resources, such resources could significantly reduce capacity need. Similarly, a smart inverter, integrated with a distribution management system, may be able to provide distributed reactive power services to maintain voltage quality.
- Supply Capacity – The extent to which DER reduce system supply capacity depends on the output expected during high-risk periods when the margin between available supply from other resources and system demand is relatively small. If local PV production reduces high system loads during summer months but drops significantly in late evening prior to the system peak, it may do little to reduce system capacity requirements. Conversely, even if PV production drops prior to evening system peaks, it may still reduce supply capacity requirements if it contributes significantly during other high-risk periods such as shoulder months when large blocks of conventional generation are unavailable due to maintenance. Determining the contribution of DER to system supply capacity requires detailed analysis of local energy resources relative to system load and conventional generation availability across all periods of the year and all years of the planning horizon.

With an integrated grid there is an opportunity for DER to contribute to capacity and ancillary services.

- **System Flexibility** – As distributed variable generation is connected to the grid, it may also impact the nature of the system supply capacity required. Capacity requirements are defined by the character of the demand they serve. Distributed resources such as PV alter electricity demand, changing the distributed load profile. PV is subject to a predictable diurnal pattern that reduces the net load to be served by the remaining system. At high levels, PV can alter the net load shape, creating additional periods when central generation must "ramp" up and down to serve load. Examples are early in the day when the sun rises and PV production increases and later, as the sun sets, when PV output drops, increasing net load. The net load shape also becomes characterized by abrupt changes during the day, as when cloud conditions change significantly.
- **Integration of DER Deployment in Grid Planning** – Adequacy of delivery and supply capacity are ensured through detailed system planning studies to understand system needs for meeting projected loads. In order for DER to contribute to meeting those capacity needs in the future, DER deployment must be included in the associated planning models. Also, because DER are located in the distribution system, certain aspects of distribution, transmission, and system reliability planning have to be more integrated. (Read more in the section, *Importance of Integrated Transmission and Distribution Planning and Operation for DER*.)
- **DER Availability and Sustainability over the Planning Horizon** – For either delivery or supply capacity, the extent to which DER can be relied upon to provide capacity service and reduce the need for new T&D and central generation infrastructure depends on planners' confidence that the resource will be available when needed across the planning horizon. To the extent that DER may be compensated for providing capacity and be unable or unwilling to perform when called upon, penalties may apply for non-performance.

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexible generation dispatch. For example, lower cost and generally large and less operationally flexible plants today typically carry load during the day. These resources may have to be augmented by smaller and more flexible assets to manage variability; however, this flexibility to handle fast ramping conditions comes with a cost. [34] [35] The potential for utilizing demand response or storage should not be overlooked, as rapid activation (on the order of seconds or minutes) could provide additional tools for system operators. Improving generator scheduling and consolidating balancing areas could improve access and utilization of ramping resources, preventing the unnecessary addition of less-efficient peaking units [36].

In addition to altering the system daily load curve, wind and solar generation's unscheduled, variable output will require more flexibile generation dispatch.

Figure 11 illustrates the importance of understanding the system to determine the value of DER. The graph shows the German power system's load profile and the substantial impact of PV power generation at higher penetration [37]. In this case, the PV resource's peak production does not coincide with the system peak, and, therefore, does not contribute to an overall reduction in system peak. From the single average plots in Figure 11, it is unclear to what extent PV might contribute to system capacity needs during critical supply hours outside of absolute system peak. During system peak, which for Germany is winter nights, the ~36 GW of installed PV does not contribute to reducing that peak. This is based on the requirements of "reliably available capacity" [38], which is defined as the percentage of installed capacity that is 99% likely to be available.

The ~33 GW of wind is also credited to a minor extent towards meeting the winter peak demand. Hydro power provides the bulk of the 12 GW of renewable resource that is considered as reliable available capacity to meet the 80 GW of winter peak load. However in the United States, where the PV peak coincides more with the system peak (depending on the facility's orientation, shading, and other factors), the results could be different. In general, however, PV without storage to achieve coincidence with system peak will be relatively ineffective in reducing capacity costs due to its variable, intermittent nature.

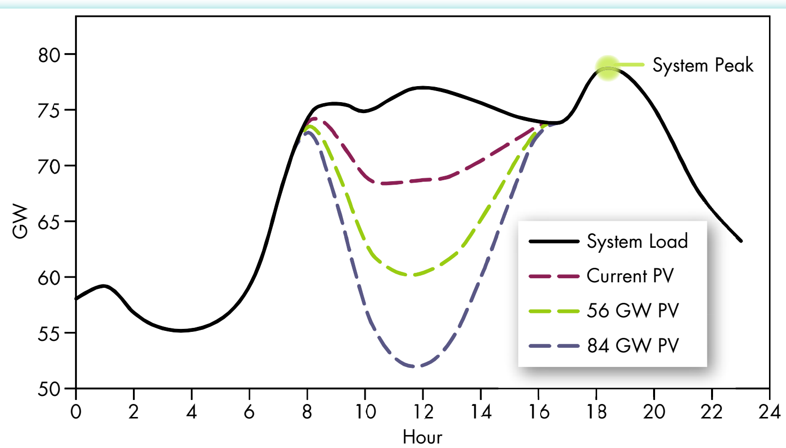


Figure 11: Peak Load Reduction and Ramp Rate Impacts Resulting from High Penetration of PV [39].

Importance of Integrated Transmission and Distribution Planning and Operation for DER

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation. As DER penetration increases and becomes concentrated in specific areas, their impact can extend beyond the distribution feeders to which they are interconnected, potentially affecting the sub-transmission and transmission systems. The aggregated impact of DER must be visible and controllable by transmission operators and must be included in transmission planning to ensure that the transmission system can be operated reliability and efficiently. Additionally, the T&D system operators must coordinate to expose DER owners to reliability needs and associated price signals. This will require significantly expanded coordination among T&D system planners and operators, as well as the development and implementation of new analysis tools, visualization capabilities, and communications and control methods.

Integrated T&D planning methods that include DER are not yet formalized, even in regions with high DER penetration levels such as Germany, Arizona, California, and Hawaii. Without a framework for integration into both T&D system operations, the cost of integration will increase significantly and the potential value of DER will not be fully realized. For example, DER installations in sub-optimal locations, such as the end of long feeders, may require significant feeder upgrades to avoid impacts to voltage quality. When strategically located, however, DER may require little or no upgrade of the feeder while delivering multiple benefits.

Examples of Integration of DER in Distribution Planning and Operations

The Hawaiian Electric Company (HECO) system on the island of Oahu had more than 150 MW of installed distributed PV in mid-2013. At this level of penetration, HECO has found it necessary to develop PV fleet forecasting methods, which it uses to provide operators with geographic information on expected PV output and potential impact on local feeder operations, as well as aggregate impact on system balancing and frequency performance. Additionally, HECO has developed detailed distribution feeder models that incorporate existing and expected future PV deployments for considering PV in planning. Although still in development, HECO is taking these steps to ensure reliability by integrating distributed PV into their operational and planning processes.

To realize their full value while ensuring power quality and reliability for all customers, DER must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation.

Realizing the importance of planning in DER procurement and operation, regulatory commissions in some cases have decided that distributed resource needs are best served by utility ownership or at least utility procurement of required distributed resources [40], [41]. Competitive procurement often reduces the asset cost while proper planning reduces integration costs and often maximizes the opportunity for capitalizing on multiple potential DER value streams. A recent ruling from the California Public Utilities Commission (CPUC) highlighted this consideration by requiring utilities to procure energy storage, ensuring that these resources are sufficiently planned in the context of the distribution grid [42].

Presently, most DER installations are "invisible" to T&D operators. The lack of coordination among DER owners, distribution operators, and transmission operators makes system operations more difficult, even as system operators remain responsible for the reliability and quality of electric service for all consumers. Likewise, utilities miss an opportunity to use DER, with the proper attributes, to support the grid. The expected services rendered from distributed storage in California are provided in Table 1. However, an integrated grid is required to enable many of these services, making integration beneficial to the entire system, not only to customers who own DER.

Category	Storage "End-Use"
Describes the point of use in the value chain	Describes the use or application of storage
Transmission/Distribution	Peak shaving
	Transmission peak capacity support (upgrade deferral)
	Transmission operation (short-duration performance, inertia, system reliability)
	Transmission congestion relief
	Distribution peak capacity support (upgrade deferral)
	Distribution operation (voltage/VAR support)
Customer	Outage mitigation: micro-grid
	Time-of-use (TOU) energy cost management
	Power quality
	Back-up power

Table 1: Expected T&D and Customer Services from Distributed Storage in California [43].

Realize the Benefits of Distributed Energy Resources

An integrated grid that enables a higher penetration of DER offers benefits to operators, customers, and society. These examples illustrate the diverse nature of these benefits:

- **Provide distribution voltage support and ride-through** – DER can provide distribution grid voltage and system disturbance performance by riding through system voltage and frequency disturbances to ensure reliability of the overall system, provided there are effective interconnection rules, smart inverters, or smart interface systems.
- **Optimize distribution operations** – This can be achieved through the coordinated control of distributed resources and the use of advanced inverters to enhance voltage control and to balance the ratio of real and reactive power needed to reduce losses and improve system stability.
- **Participate in demand response programs** – Combining communication and control expands customer opportunities to alter energy use based on prevailing system conditions and supply costs. Specifically with respect to ancillary services, connectivity and distribution management systems facilitate consumer participation in demand response programs such as dynamic pricing, interruptible tariffs, and direct load control.
- **Improve voltage quality and reduced system losses** – Included in this are improved voltage regulation overall and a flatter voltage profile, while reducing losses.
- **Reduce environmental impact** – Renewable distributed generation can reduce power system emissions, and an integrated approach can avoid additional emissions by reducing the need for emissions-producing backup generation. Also contributing will be the aggregation of low-emissions distributed resources such as energy storage, combined heat and power, and demand response.
- **Defer capacity upgrades** – With proper planning and targeted deployment, the installation of DER may defer the need for capacity upgrades for generation, transmission, and/or distribution systems.
- **Improve power system resiliency** – Within an integrated grid, distributed generation can improve the power system's resiliency, supporting portions of the distribution system during outages or enabling consumers to sustain building services, at least in part. Key to doing this safely and effectively is the seamless integration of the existing grid and DER.

Figure 12 illustrates a concept of an integrated grid with DER in residences, campuses, and commercial buildings networked as a distributed energy network and described in a recent EPRI report [44].

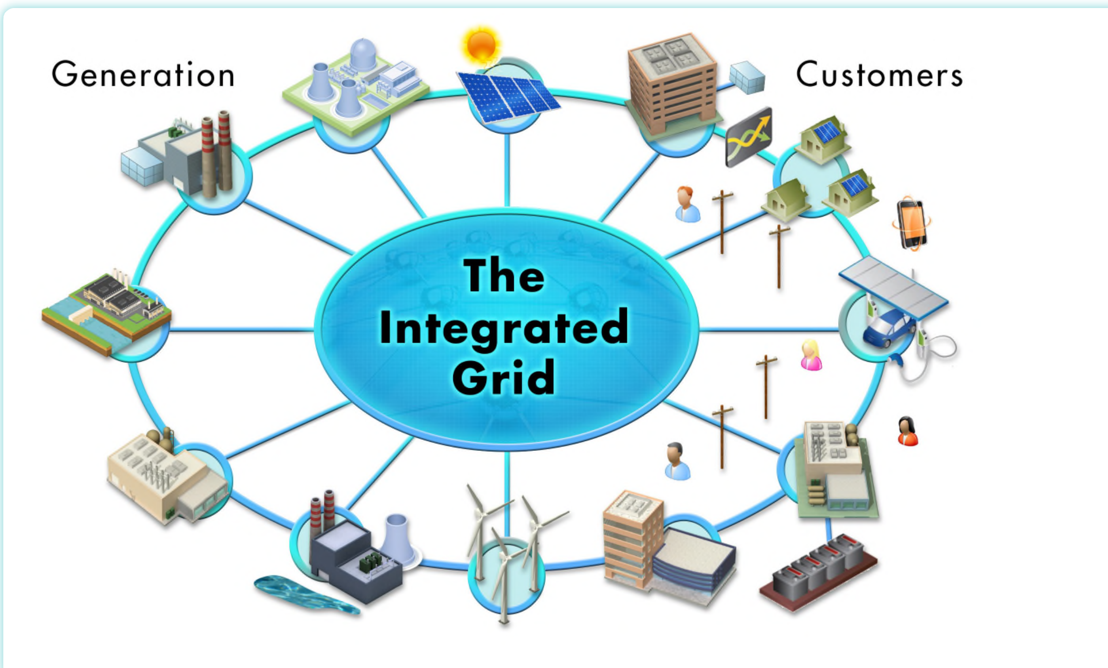


Figure 12: Creating an Architecture with Multi-Level Controller [44].

Grid Modernization: Imperative for the Integrated Grid

Grid modernization of the distribution system will include re-conductoring, and augmenting its infrastructure along with deploying smart technologies such as distribution management systems (DMS), communication, sensors, and energy storage is a key component of moving to the Integrated Grid. It is anticipated that this combination of infrastructure reinforcement and smart technology deployment can yield the lowest-cost solution for a given penetration level of DER in a feeder.

Table 2 shows a menu of technology options for the DSO side, the consumer side, and the integration of the two that will enable a distribution feeder to reliably integrate greater DER penetration [45], [46]. The solutions, which have been outlined and evaluated by others in the industry, are organized as follows:

- System operator solutions are those actions that the DSO could take to bolster the performance and reliability of the system where DER deployment is growing.
- Interactive solutions are those that require close coordination between the system operator and DER owner and generally provide the operator the ability to interact with the DER owner's system to help maintain reliable system operation.
- DER owner solutions are those that could be employed at the customer end of the system through installation of technology or operational response measures.

A comprehensive understanding of each approach is beyond the scope of this paper but is an important element of EPRI's proposed work. Assuming that any grid investment will be paid for by customers, it is important to determine if, and under what situations, such investments may prove cost-effective and in the public interest.

The coordinated demonstration of each option outlined in Table 2 across different types of distribution system feeders can help provide a knowledge repository that stakeholders can use to determine the prudence of the various investments needed to achieve an integrated grid. Such demonstrations also can provide information essential for all stakeholders regarding rules of engagement among DER owners, DSOs, TSOs, and ISOs.

No one entity has the resources to conduct the demonstrations and the associated engineering analysis to document costs, benefits, and performance of all technology options across all types of distribution feeders. EPRI proposes using its collaborative approach globally to develop a comprehensive repository of data and information that can be used to move toward the Integrated Grid.

System Operator Solutions	Interactive Solutions	DER Owner Solutions
Network reinforcement	Price-based demand response	Local storage
Centralized voltage control	Direct load control	Self-consumption
Static VAR compensators	On-demand reactive power	Power factor control
Central storage	On-demand curtailment	Direct voltage control
Network reconfiguration	Wide-area voltage control	Frequency-based curtailment

Table 2: Technology Options [45], [46].

Action Plan

The current and projected expansion of DER may significantly change the technical, operational, environmental, and financial characteristics of the electricity sector. An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. Interconnection Rules and Communications Technologies and Standards
   - ***Interconnection rules*** that preserve voltage support and grid management
   - ***Situational awareness*** in operations and long-term planning, including rules of the road for installing and operating distributed generation and storage devices
   - Robust ***information and communication technologies***, including high-speed data processing, to allow for seamless interconnection while assuring high levels of cyber security
   - A ***standard language and a common information model*** to enable interoperability among DER of different types, from different manufacturers, and with different energy management systems

2. Assessment and Deployment of Advanced Distribution and Reliability Technologies
   - ***Smart inverters*** that enable DER to provide voltage and frequency support and to communicate with energy management systems [1]
   - ***Distribution management systems and ubiquitous sensors*** through which operators can reliably integrate distributed generation, storage, and end-use devices while also interconnecting those systems with transmission resources in real time [2]
   - ***Distributed energy storage and demand response***, integrated with the energy management system [3]

3. Strategies for Integrating DER with Grid Planning and Operation
   - ***Distribution planning and operational processes*** that incorporate DER
   - ***Frameworks for data exchange and coordination*** among DER owners, DSOs, and organizations responsible for transmission planning and operations
   - Flexibility to ***redefine roles and responsibilities*** of DSOs and ISOs

4. Enabling Policy and Regulation
   - ***Capacity-related costs*** must become a distinct element of the cost of grid-supplied electricity to ensure long-term system reliability
   - ***Power market rules*** that ensure long term adequacy of both energy and capacity
   - ***Policy and regulatory framework*** to ensure that costs incurred to transform to an integrated grid are allocated and recovered responsibly, efficiently, and equitably
   - ***New market frameworks*** using economics and engineering to equip investors and other stakeholders in assessing potential contributions of distributed resources to system capacity and energy costs

Next Steps for EPRI

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative.

Phase I – Develop a Concept Paper

This concept paper was developed to align stakeholders on the main issues while outlining real examples to support open fact-based discussion. Input and review was provided by various stakeholders from the energy sector including utilities, regulatory agencies, equipment suppliers, non-governmental organizations (NGOs), and other interested parties. The publication of this paper will be followed by a series of public presentations and additional topical papers of a more technical nature that will more completely analyze various aspects of the Integrated Grid and lessons learned from regions where DER penetration has increased.

Phase II – Develop an Assessment Framework

In this six-month project, EPRI will develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid. Such a framework is required to ensure consistency in the comparison of options and to build a resource library that will inform the Phase III demonstration program.

In order to organize a comprehensive framework, EPRI will analyze system operator, DER owner, and interactive options listed in Table 2. Since each country, state, region, utility, and feeder may have differing characteristics that lead to different optimized solutions, efforts will be made to ensure that the framework is flexible enough to accommodate these differences.

Additionally, a testing protocol will be developed in support of the Phase III global demonstration program to ensure that a representative sample of systems and solutions will be tested.

Phase III – Conduct a Global Demonstration and Modeling Program

Phase III will focus on conducting global demonstrations and modeling using the analytics and procedures developed in Phase II to provide data and information that stakeholders will need for the system-wide implementation of integrated grid technologies in the most cost-effective manner.

Using the Phase II framework and resource library, participants in Phase III can combine and integrate their various experiments and demonstrations under a consistent protocol. However, it is neither economic nor practical for an individual DSO to apply all the technological approaches across different types of distribution circuits. Therefore, Phase III, planned as a two-year effort, will present the opportunity for utilities globally to collaborate to assess the cost, benefit, performance, and operational requirements of different technological approaches to an integrated grid.

Demonstrations and modeling projects in areas where DER deployment is not expected near term will use the analytics and procedures developed in Phase II to ensure that results can provide data and information that utilities will need for planning investments in the system-wide implementation of integrated grid technologies.

With research organizations and technology providers working with distribution companies on individual demonstration projects, EPRI can work to ensure that findings and lessons learned are shared, and to consolidate the evaluations of the different approaches. The lessons learned from the real life demonstrations will be assembled in a technology evaluation guidebook, information resources, and analysis tools.

New technologies for grid modernization will continue to evolve as the transformation to an integrated grid continues in this decade and beyond. The effort outlined in Phase II and Phase III will not be a one-time event but will set the stage for ongoing technology development and optimization of the integrated grid concept. As new technology evolves, a comprehensive framework for assessment of the technology as outlined in Phases II and III can support prudent investment for grid modernization using solid scientific assessment before system-wide deployment.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration.

Outputs from the Three-Phase EPRI Initiative

Taken together, Phases II and III will help identify the technology combinations that will lead cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. Also to be developed are interface requirements that help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. The information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system and inform policymakers and regulators as they implement enabling policy and regulation. The development of a consistent framework backed up with data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid in order to effectively integrate large amounts of DER into the existing power system.

A key deliverable from the Phase II and III efforts will be a comprehensive guidebook, analytical tools, and a resource library for evaluating combinations of technologies in distribution system circuits. In order to maximize the value of these deliverables, EPRI will seek to partner with organizations that are leading integrated grid-style analyses and demonstration projects to ensure that all have access to the full database of inputs and outputs from these important projects even if they were not directly involved in the technical work. Key components of the guidebook, analytical tools, and resource library will include:

- Comprehensive descriptions of technological approaches and how they can be applied in a distribution system
- Modeling tools and approaches required to assess the performance of the technical solutions
- Operational interface that will be required between DER owners and DSOs
- Analytics to assess the hosting capacity of distribution circuits
- Analytics to evaluate technology options and costs to support greater penetration of DER
- Analytics to characterize the value of integrated grid approaches beyond increasing feeder hosting capacity

A collaborative approach will be essential to develop the comprehensive knowledge repository of costs, benefits, performance, and operational requirements of the multitude of technical approaches that can be implemented in a given distribution feeder for a specific level of DER integration. The guidebook, analytical tools, and resource library will build on prior work of EPRI and other research organizations to develop a portfolio of solution options outlined in Table 2. They will also use the DOE/EPRI cost/benefit framework for evaluating smart grid investments as part of smart grid demonstrations around the world [47].

Conclusion

Changes to the electric power system with the rise of DER have had a substantial impact on the operation of the electric power grid in places such as Germany and Hawaii. As consumers continue to exercise their choice in technology and service, as technologies improve in performance and cost, and as federal and regional policy incentives are passed, DER could become even more pervasive.

DER deployment may provide several benefits, including reduced environmental impact, deferred capacity upgrades, optimized distribution operations, demand response capabilities, and improved power system resiliency. The successful integration of DER depends pivotally on the existing electric power grid, especially its distribution systems, which were not designed to accommodate a high penetration of DER while sustaining high levels of electric quality and reliability. Certain types of DER operate with more variability and intermittency than the central power stations on which the existing power system is based. The grid provides support that balances out the variability and intermittency while also providing other services that may be difficult to replicate locally.

An integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity will require global collaboration in the following four key areas:

1. **Interconnection Rules and Communications Technologies and Standards**
2. **Assessment and Deployment of Advanced Distribution and Reliability Technologies**
3. **Strategies for Integrating DER with Grid Planning and Operation**
4. **Enabling Policy and Regulation**

In order to provide the knowledge, information, and tools that will inform key stakeholders as they take part in shaping the four key areas supporting transformation of the power system, EPRI has begun work on a three-phase initiative:

- Phase I – Align stakeholders with a concept paper (this document).
- Phase II – Develop a framework for assessing the costs and benefits of combinations of technology that lead to an integrated grid.
- Phase III – Initiate a worldwide demonstration program to provide data to those seeking to implement integrated grid solutions.

The initiative will help identify the technology combinations that will lead to cost-effective and prudent investment to modernize the grid while supporting the technical basis for DER interconnection requirements. It will develop interface requirements to help define the technical basis for the relationship between DER owners, DSOs, and TSOs or ISOs. Finally, the information developed, aggregated, and analyzed in Phases II and III will help identify planning and operational requirements for DER in the power system while supporting the robust evaluation of the capacity and energy contribution from both central and distributed resources.

The development of a consistent framework supported by data from a global technology demonstration and modeling program will support cost-effective and prudent investments to modernize the grid and the effective, large-scale integration of DER into the power system. The development of a large collaborative of stakeholders will help the industry move in a consistent direction to achieve an integrated grid.

References

[1] "Common Functions for Smart Inverters, Version 2," EPRI, Palo Alto, CA, 2012. 1026809.

[2] "Integrating Smart Distributed Energy Resources with Distribution Management Systems," EPRI, Palo Alto, CA, 2012. 1024360.

[3] "2012 Grid Strategy: Distribution Management System (DMS) Advanced Applications for Distributed Energy Resources," EPRI, Palo Alto, CA, October 2012. 1025572.

[4] "Key Facts About the Electric Power Industry," Edison Electric Institute, Washington, DC, 2013.

[5] "Electric Power Annual," Energy Information Administration (EIA), Washington, DC, 2012.

[6] "IEEE Distribution Reliability Benchmarking 2011 Results," IEEE Distribution Reliability Working Group, 2013.

[7] "Renewable Energy Medium-Term Market Report," International Energy Agency (IEA), Paris, 2013.

[8] "Recent Facts About Photovoltaics in Germany," Fraunhofer Institute, Freiburg, September 2013.

[9] "Annual Updates and Trends Report," Interstate Renewable Energy Council (IREC), Chicago, 2013.

[10] "Combined Heat and Power: A Clean Energy Solution," U.S. Department of Energy (DOE), Washington, D.C., August 2012.

[11] W. Yan et. al., "Operation Strategies in Distribution Systems with High Level PV Penetration," in *ISES Solar World Congress*, Kassel, 2011.

[12] B. I. Craciun et al., "Overview of Recent Grid Codes for PV Power Integration," in *13th International Conference on Optimization of Electrical and Electronic Equipment (OPTIM)*, 2012.

[13] K. Schmitz and C. Weber, "Does One Design Fit All? On the Transferability of the PJM Market Design to the German Electricity Market," Essen, 2013.

[14] P. Tielens and D. Van Hertem, "Grid Inertia and Frequency Control in Power Systems with High Penetration of Renewables," in *Young Researchers Symposium in Electrical Power Engineering*, Delft, 2012.

[15] "Grid Impacts of Distributed Generation with Advanced Inverter Functions: Hosting Capacity of Large-Scale PV Using Smart Inverters," EPRI, Palo Alto, CA, 2013. 3002001246.

[16] J. Smith, M. Rylander, and W. Sunderman, "The Use of Smart Inverter Controls for Accommodating High-Penetration Solar PV," in *Distributech Conference and Exhibition*, San Diego, CA, 2013.

[17] "Power Generation Systems Connected to the LV Distribution Network," VDE-AR-N 4105, Offenbach, August 2011.

[18] "Technical Guideline: Generating Plants Connected to the MV Network," BDEW, Berlin, 2013.

[19] "European Network Code Development: The importance of network codes in delivering a secure, competitive and low carbon European electricity market," ENTSO-E, March 2013.

[20] "Network Code for Requirements for Grid Connection Applicable to all Generators," ENTSO-E, March 2013.

[21] "Distribution Grid Study," Deutsche Energie-Agentur (DENA), Berlin, 2012.

[22] Jeffrey Sparshot. (2013, September) About 1 in 3 Households Has No Landline Phone. [Online]. http://blogs.wsj.com/economics/2013/09/05/about-1-in-3-households-has-no-landline-phone/

[23] "Benefits Provided to Distributed Generation by a Parallel Utility System Connection," EPRI, Palo Alto, CA, 2003. 1001668.

[24] "Operation and Application of Variable Frequency Drive (VFD) Technology," Carrier Corporation, Syracuse, NY, 2005.

[25] T. D. Kefalas and A. G. Kladas, "Grid Voltage Harmonics Effect on Distribution Transformer Operation," in *7th Mediterranean Conference and Exhibition on Power Generation, Transmission, Distribution and Energy Conversion (MedPower 2010)*, 2010.

[26] "Reciprocating Engines for Stationary Power Generation," EPRI, Palo Alto, CA, 1999. TR-113894.

[27] "Annual Energy Outlook 2012," Energy Information Administration (EIA), Washington, DC, April 2012. DOE/EIA-0383.

[28] "California Net Energy Metering (NEM) Draft Cost-Effectiveness Evaluation," Energy and Environment Economics (E3), San Francisco, CA, 2013.

[29] "2010 PJM Market Highlights: A Summary of Trends and Insights," PJM, Valley Forge, PA, 2011.

[30] J. C. Bonbright, A. L. Danielsen, and D. R. Kamerschen, *Principles of Public Utility Rates*. Public Utilities Report, Inc., 1988.

[31] A. E. Kahn, *The Economics of Regulation: Principles and Institutions*. MIT, 1988.

[32] A. Faruqui, R. Hledik, and B. Neenan, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators," Demand Response Research Center, 2007.

[33] "DS3: System Services Review – TSO Recommendations," EirGrid and SONI, Dublin, June 2012.

[34] E. Ela, M. Milligan, and B. Kirby, "Operating Reserves and Variable Generation," NREL, Golden, CO, 2011. NREL/TP-5500-51978.

[35] M. Hummon et al., "Fundamental Drivers of the Cost and Price of Operating Reserves," NREL, Golden, CO, 2013. NREL/TP-6A20-58491.

[36] "Flexibility Requirements and Metrics for Variable Generation," North American Electric Reliability Council (NERC), Princeton, NJ, August 2010.

[37] "Fast Facts: What the Duck Curve Tells Us About Managing a Green Grid," California ISO, Folsom, CA, 2013.

[38] "Germany's New Energy Policy," Federal Ministry of Economics and Technology (BMWi), Berlin, 2012.

[39] E. Lannoye, "Quantifying and Delivering Flexibility in Power Systems," University College Dublin, 2013.

[40] A. Mills and R. Wiser, "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," Lawrence Berkeley National Laboratory, December 2012.

[41] "2011 ERP All-Source Solicitation: Renewable Resource RFP," Public Service Company of Colorado, Denver, CO, 2011.

[42] "Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems," California Public Utilities Commission (CPUC), 2013.

[43] E. Malashenko et. al., "Energy Storage Framework Staff Proposal," California Public Utilities Commission (CPUC), April 2012.

[44] "ElectriNet," EPRI, Palo Alto, CA, 2009. 1018848.

[45] M. Vandenbergh et. al., "Technical Solutions Supporting the Large Scale Integration of Photovoltaic Systems in the Future Distribution Grids," in *22nd International Conference on Electricity Distribution (CIRED)*, 2013.

[46] "Prioritisation of Technical Solutions Available for the Integration of PV into the Distribution Grid," PV Grid, 2013.

[47] "Estimating the Costs and Benefits of the Smart Grid," EPRI, Palo Alto, CA, 2011. 1022519.

Appendix A – Cost Calculations

Generation, Transmission, and Distribution vs. Cost of Energy and Capacity

Generation, transmission, and distribution breakdowns are provided from EIA estimates in ($/kWh), assuming an average customer usage of 982 kWh/month.

Generation is broken into two components (energy and capacity) based on PJM market estimates of the price breakdown: "2010 PJM Market Highlights: A Summary of Trends and Insights." 2011. http://www.pjm.com/~/media/documents/reports/20110513-2010-pjm-market-highlights.ashx

Of which, 80% was estimated as energy related, while the other 20% was attributed to capacity.

Distribution and transmission are estimated based on the following breakdown from SCE (E3 NEM Effectiveness Report): http://www.ethree.com/documents/CSI/CPUC_NEM_Draft_Report_9-26-13.pdf

Among the appendices, Southern California Edison's (SCE's) implied transmission and distribution (T&D) costs were provided. When those costs were scaled back to national average values, the percentages are provided below:

SCE Implied Cost breakdowns (when scaled to $40/month)

Cost Breakdown	$/Month	Fixed %	Variable %	Fixed ($)	Variable ($)
Customer	$14.29	100%	0%	$14.29	$–
Distribution	$15.71	90%	10%	$14.14	$1.57
Sub-transmission	$4.29	60%	40%	$2.57	$1.71
Transmission	$5.71	100%	0%	$5.71	$–
TOTAL	$40.00			$36.71	$3.29

Thus the variable (energy-based) T&D costs were taken at $3/month.

Cost of Off-Grid Residential Solutions

Cost figures reflect the additional cost to take a residence that produces 100% of its energy locally (from PV) and turn it into a self-sufficient entity that can operate without a grid connection.

These costs include the following, which are then amortized across the lifetime of the project (20 years):

- Extra PV panels (beyond the annual kWh requirement)
- Battery storage
- Charge controller
- Backup generator

Software Package: HOMER Energy (Hourly energy profile simulator)
Locations: St. Louis, MO and San Francisco, CA
Analysis includes appropriate incentives Federal ITC and net-energy-metering

Location	St. Louis, MO	San Francisco, CA
Load Profile (OpenEI)	12MWh/yr	7.67MWh/yr
Real Interest Rate	3.5% (5.5% APR – 2% inflation)	
Project Lifetime	20 years (no salvage)	
PV System (Array + Inverter) Installed Cost	$3-$4/W installed (after incentive) [2013] $1.50-$2/W installed [2020]	
Battery Cost	$450-$550/installed kWh [2013] $200-$300/installed kWh [2020]	
Generator	$400/kW	
System Controller	$600/kW	
System O&M	$32/kW/yr PV system O&M + $0.50/hr generator O&M + $3/battery/yr	

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together . . . Shaping the Future of Electricity

3002002733 February 2014

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Schedule NG-4

Schedule NG - 4

U.S. PV Capacity as a Percentage of Total Capacity Compared With Germany at the Beginning of Its “Energy Transformation” (Figure 2 from the EPRI Paper)

The Growth in Deployment of Distributed Energy Resources

The classic vision of electric power grids with one-way flow may now be changing. Consumers, energy suppliers, and developers increasingly are adopting DER to supplement or supplant grid-provided electricity. This is particularly notable with respect to distributed PV power generation—for example, solar panels on homes and stores—which has increased from approximately 4 GW of global installed capacity in 2003 to nearly 128 GW in 2013 [7]. In Germany, the present capacity of solar generation is approximately 36 GW, while the daily system peak demand ranges from about 40 to 80 GW. By the end of 2012, Germany's PV capacity was spread across approximately 1.3 million residences, businesses, and industries and exceeded the capacity of any other single power generation technology in the country [8]. This rapid spread of DER reflects a variety of public and political pressures along with important changes in technology. This paper focuses on system operation impacts as DER reaches large scales.

By the end of 2013, U.S. PV installations had grown to nearly 10 GW. Although parts of the U.S. have higher regional penetration of PV, this 10 GW represents less than 2% of total installed U.S. generation capacity [9], which matches German PV penetration in 2003 (Figure 2). With PV growth projected to increase in scale and pace over the next decade, now is the time to consider lessons from Germany and other areas with high penetration of distributed resources.

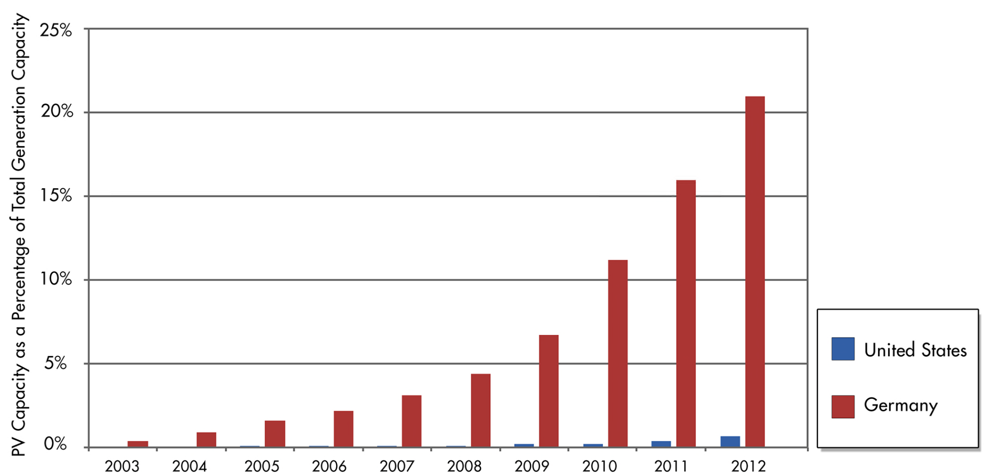


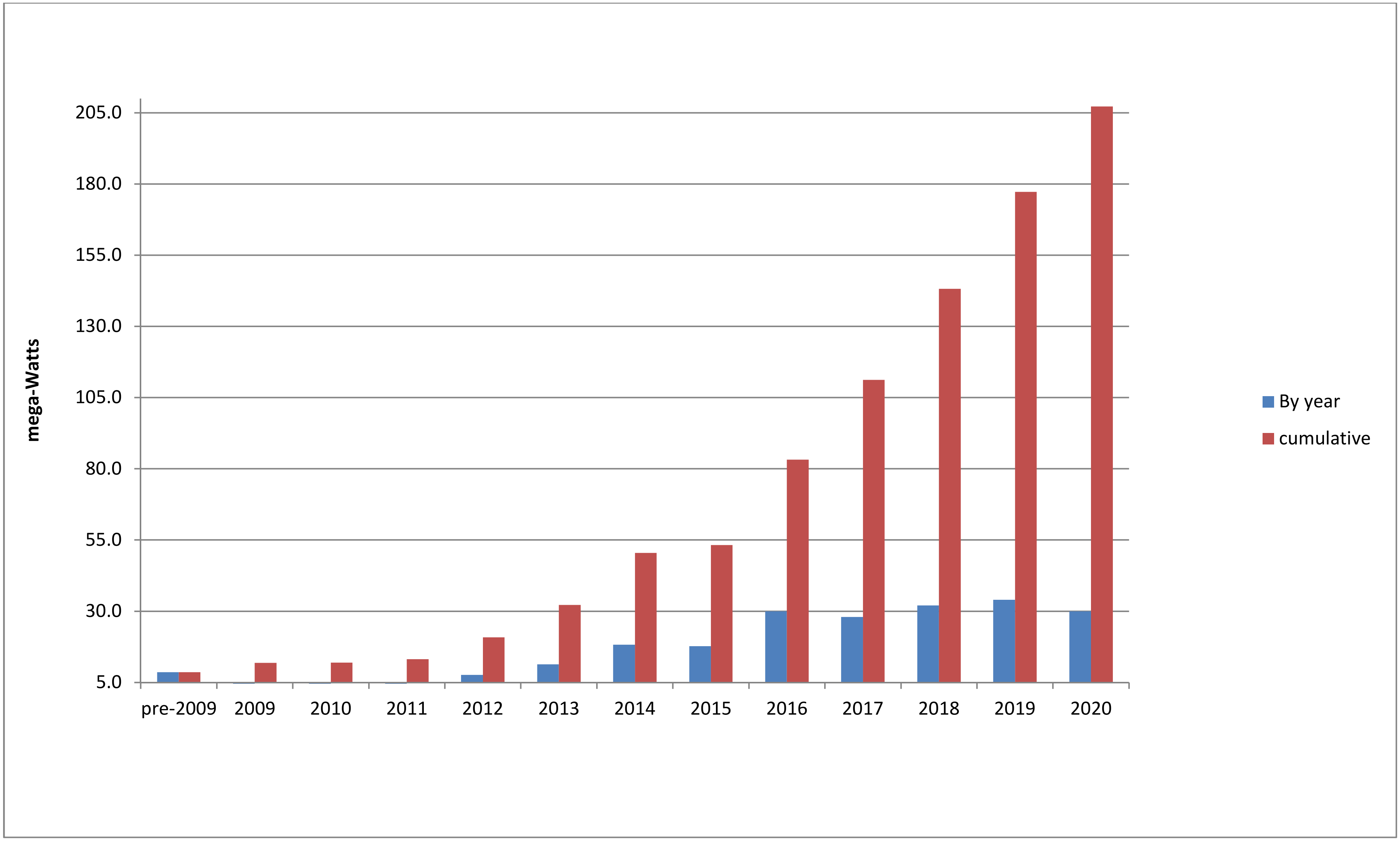
Figure 2: U.S. PV Capacity as a Percentage of Total Capacity Compared with Germany at the Beginning of Its "Energy Transformation."

Schedule NG-5

Schedule NG - 5

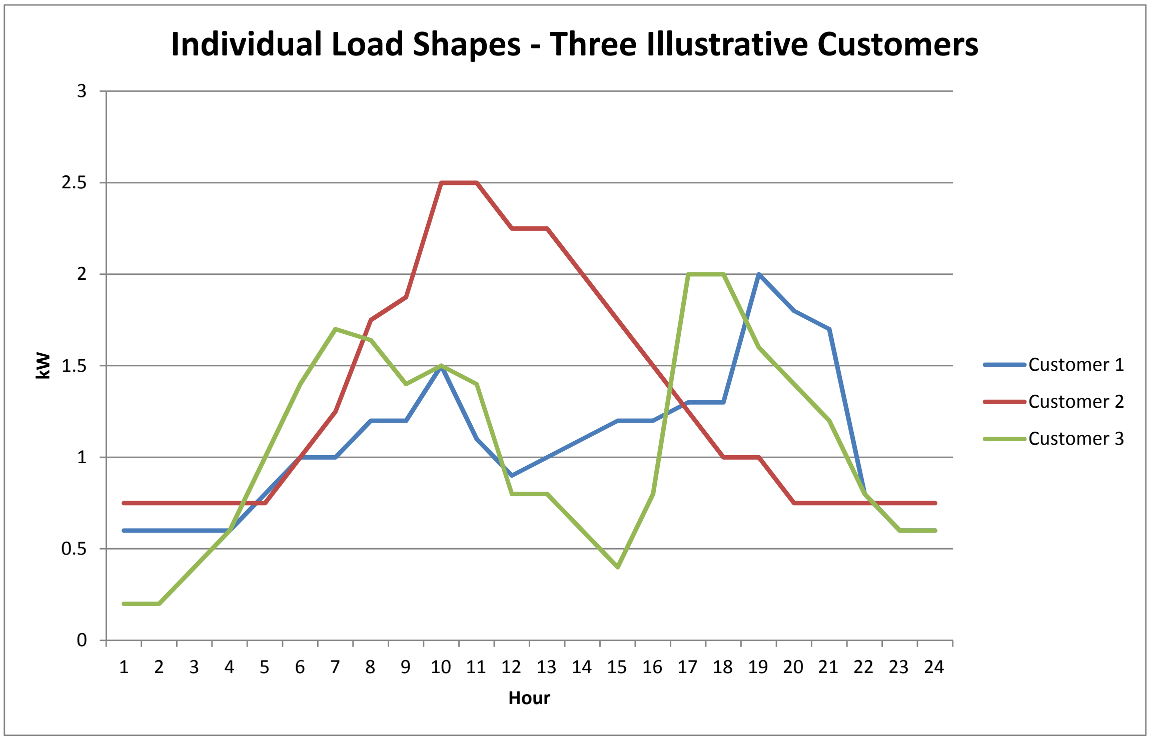
Estimate of Installed DG in RI through 2020

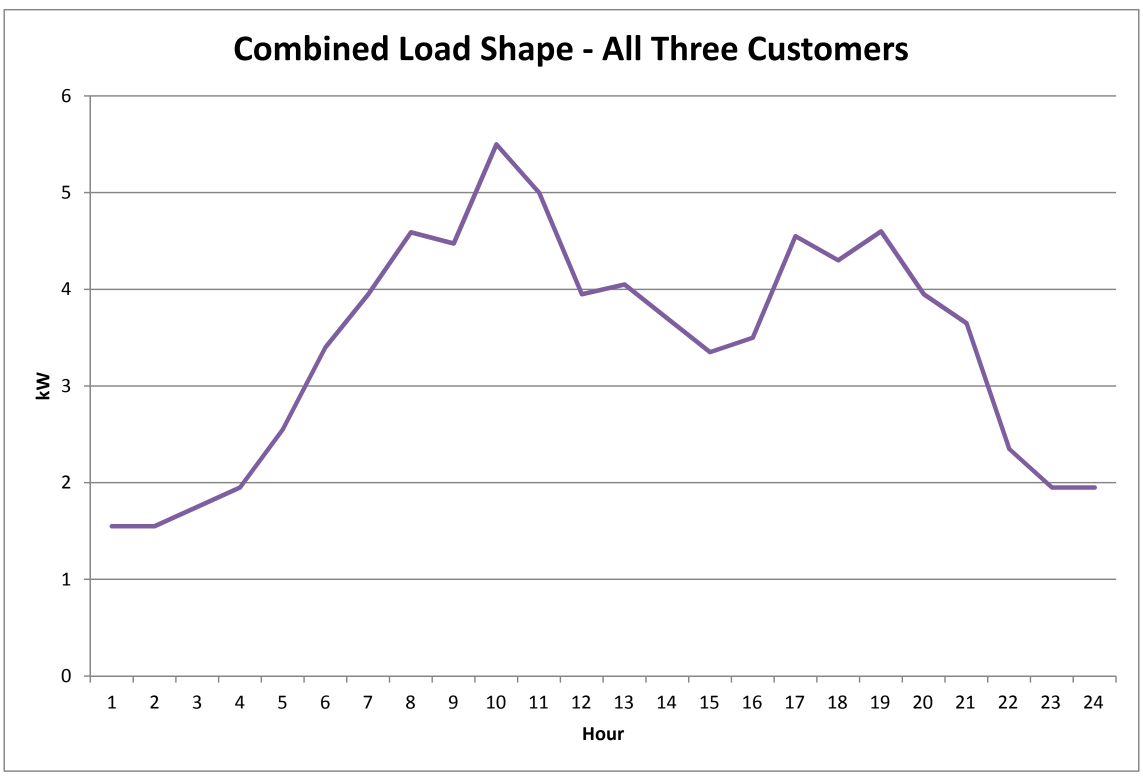
Estimated Amount of Distribution Generation Installed in Rhode Island Through 2020



Schedule NG - 6

Illustration of Customer Diversity

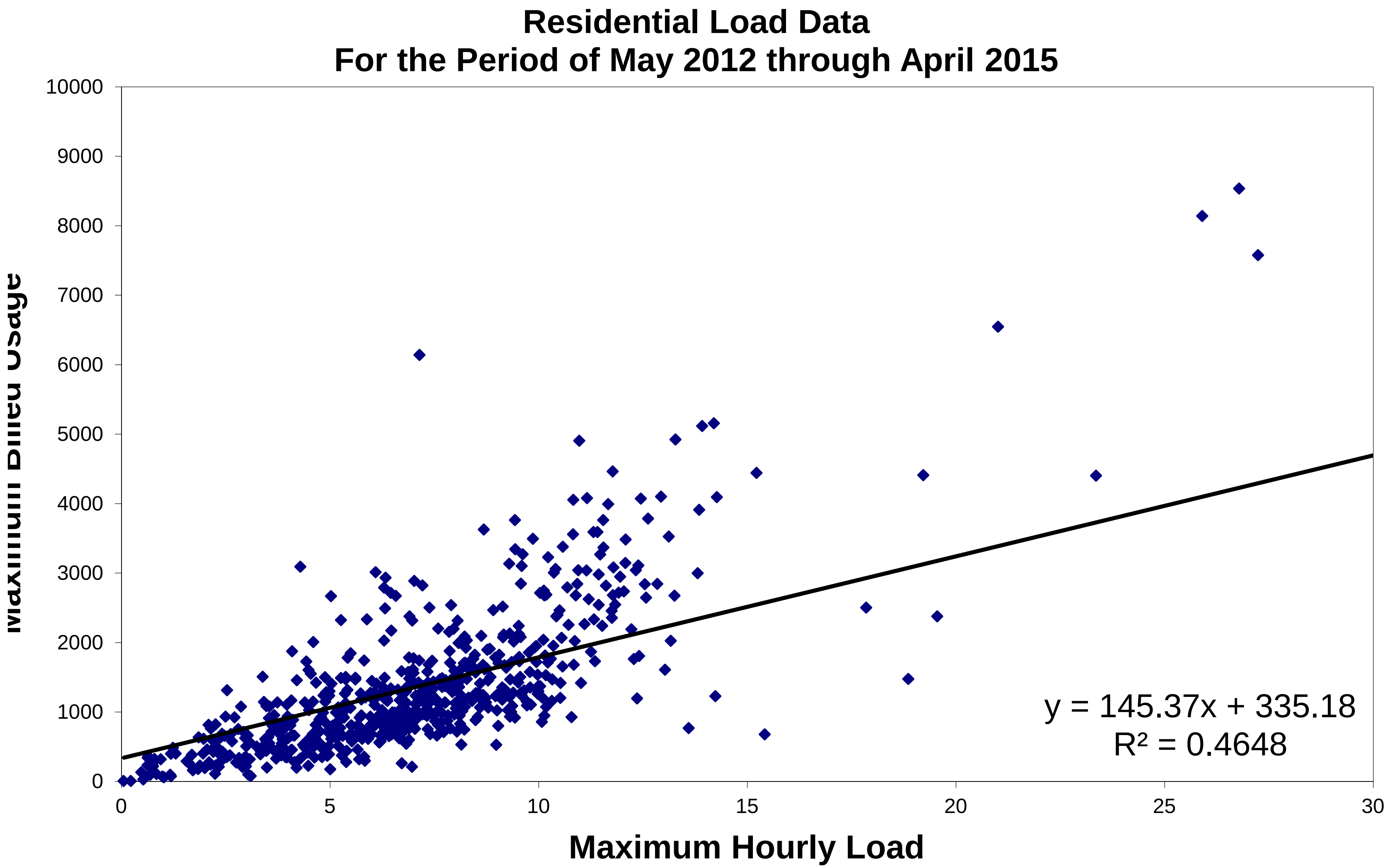

Individual Load Shapes - Three Illustrative Customers
kW
3
2.5
2
1.5
1
0.5
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour
Customer 1
Customer 2
Customer 3

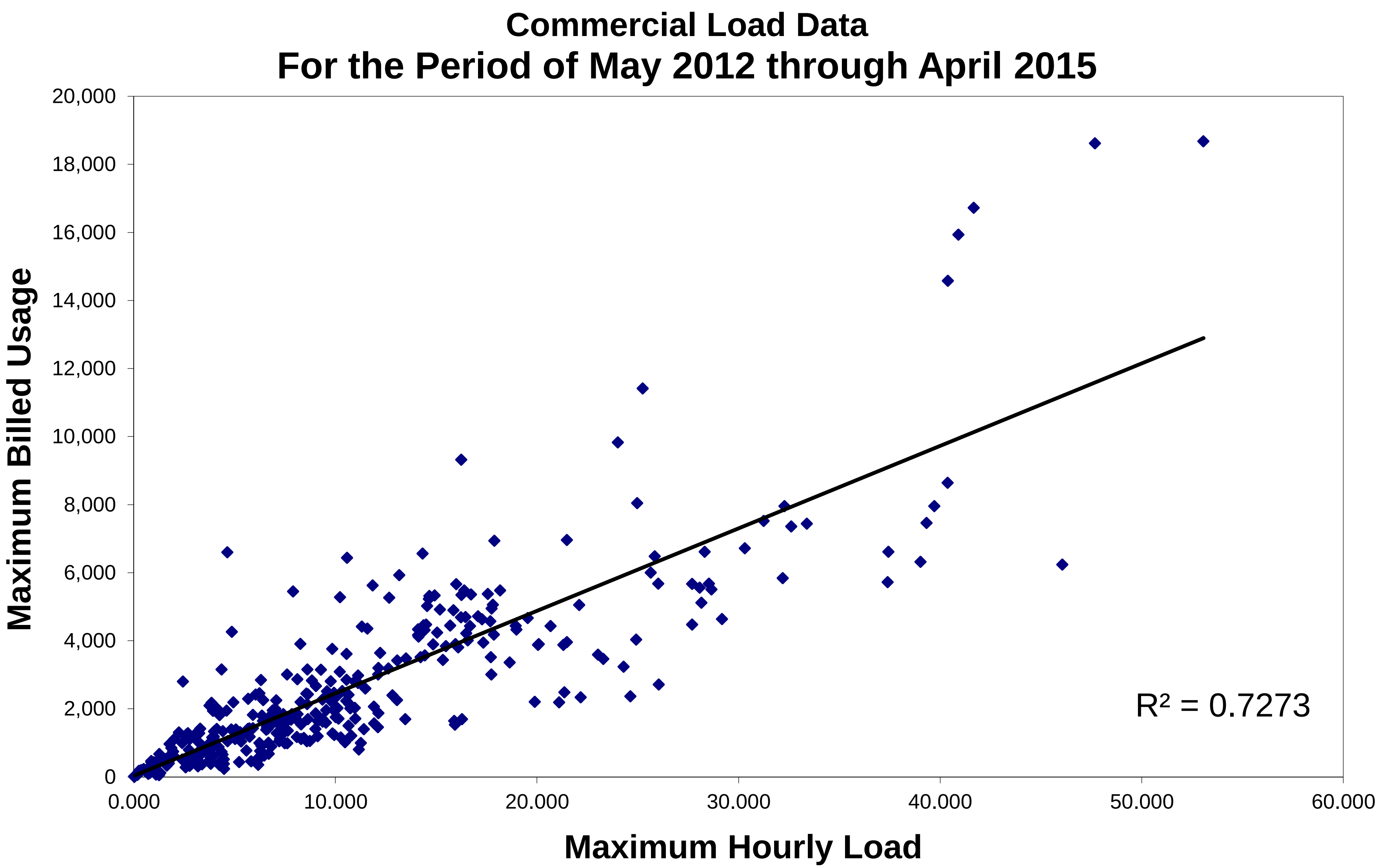

Combined Load Shape - All Three Customers
kW
6
5
4
3
2
1
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Schedule NG-7

Schedule NG - 7

Relationship between Maximum Monthly Use and Maximum kW


Residential Load Data
For the Period of May 2012 through April 2015
Maximum Billed Usage
10000
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
0
5
10
15
20
25
30
Maximum Hourly Load
y = 145.37x + 335.18
R² = 0.4648


Commercial Load Data
For the Period of May 2012 through April 2015
Maximum Billed Usage
20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
0.000
10.000
20.000
30.000
40.000
50.000
60.000
Maximum Hourly Load
R² = 0.7273

Schedule NG-8

Schedule NG - 8

Typical Residential Monthly Bill by Component

The Narragansett Electric Company
Typical Bill - Basic Residential (Rate A-16) Customer

Monthly Usage 500 kWh

		Current Rates	Bill Charges	% of Tot Bill	Proposed Rates	Bill Charges	% of Tot Bill	Difference	% Difference
1	Customer Charge	$5.00	$5.00	5.0%	$8.50	$8.50	8.7%	$3.50	70.0%
2	Distribution Energy Charge	$0.04065	$20.33	20.5%	$0.03026	$15.13	15.6%	($5.20)	-25.6%
3	Subtotal Distribution		$25.33	25.6%		$23.63	24.3%	($1.70)	-6.7%
4									
5	LIHEAP Charge	$0.73	$0.73	0.7%	$0.73	$0.73	0.8%	$0.00	0.0%
6	Transmission Energy Charge	$0.02348	$11.74	11.9%	$0.02348	$11.74	12.1%	$0.00	0.0%
7	Transition Energy Charge	($0.00201)	($1.01)	-1.0%	($0.00201)	($1.01)	-1.0%	$0.00	0.0%
8	Energy Efficiency Program Charge	$0.00983	$4.92	5.0%	$0.00983	$4.92	5.1%	$0.00	0.0%
9	Renewable Energy Distribution Charge	$0.00232	$1.16	1.2%	$0.00232	$1.16	1.2%	$0.00	0.0%
10	RE Growth Program	$0.17	$0.17	0.2%	$0.17	$0.17	0.2%	$0.00	0.0%
11	Subtotal Other Delivery Service		$17.71	17.9%		$17.71	18.2%	$0.00	0.0%
12									
13	Standard Offer Charge	$0.10111	$50.56	51.1%	$0.10111	$50.56	52.0%	$0.00	0.0%
14	Renewable Ege Std Charge	$0.00294	$1.47	1.5%	$0.00294	$1.47	1.5%	$0.00	0.0%
15	Subtotal Supply Service		$52.03	52.5%		$52.03	53.5%	$0.00	0.0%
16		$0.07427							
17	Subtotal before GET		$95.07	96.0%		$93.37	96.0%	($1.70)	-1.8%
18									
19	Gross Earnings Tax	4%	$3.96	4.0%	4%	$3.89	4.0%	($0.07)	-1.8%
20									
21	Total Bill including GET		$99.03	100.0%		$97.26	100.0%	($1.77)	-1.8%

******Based on Rates in effect as of July 1, 2015**

Schedule NG-9

Schedule NG - 9

Illustration of Customer Savings from Energy Efficiency

The Narragansett Electric Company
Typical Bill - Basic Residential Rate A-16 Customer
Savings based on Current Rates

		Monthly Usage : 1000		Monthly Usage : 500			
		Current Rates	Bill Charges	Current Rates	Bill Charges	Difference	% Difference
1	Customer Charge	$5.00	$5.00	$5.00	$5.00	$0.00	0.0%
2	Distribution Energy Charge	$0.04065	$40.65	$0.04065	$20.33	($20.32)	-50.0%
3	Subtotal Distribution		$45.65		$25.33	($20.32)	-44.5%
4							
5							
6	LIHEAP Charge	$0.73	$0.73	$0.73	$0.73	$0.00	0.0%
7	Transmission Energy Charge	$0.02348	$23.48	$0.02348	$11.74	($11.74)	-50.0%
8	Transition Energy Charge	($0.00201)	($2.01)	($0.00201)	($1.01)	$1.00	-49.8%
9	Energy Efficiency Program Charge	$0.00983	$9.83	$0.00983	$4.92	($4.91)	-49.9%
10	Renewable Energy Distribution Charge	$0.00232	$2.32	$0.00232	$1.16	($1.16)	-50.0%
11	RE Growth Program	$0.17	$0.17	$0.17	$0.17	$0.00	0.0%
12	Subtotal Other Delivery Service		$34.52		$17.71	($16.81)	-48.7%
13							
14	Standard Offer Charge	$0.10111	$101.11	$0.10111	$50.56	($50.55)	-50.0%
15	Renewable Ege Std Charge	$0.00294	$2.94	$0.00294	$1.47	($1.47)	-50.0%
16	Subtotal Supply Service		$104.05		$52.03	($52.02)	-50.0%
17							
18	Subtotal before GET		$184.22		$95.07	($89.15)	-48.4%
19							
20	Gross Earnings Tax	4%	$7.68	4%	$3.96	($3.71)	-48.3%
21							
22	Total Bill including GET		$191.90		$99.03	($92.86)	-48.4%

******Based on Rates in effect as of July 1, 2015**

The Narragansett Electric Company
Typical Bill - Basic Residential Rate A-16 Customer
Savings based on Proposed Rates

				Savings - Next 11 months				Savings - After 11 months			
	Monthly Usage:	1000		500				500			
	Rate A-16 - Regular Residential	Proposed Rates	Bill Charges	Proposed Rates	Bill Charges	Difference	% Difference	Proposed Rates	Bill Charges	Difference	% Difference
1	Customer Charge	$13.00	$13.00	$13.00	$13.00	$0.00	0.0%	$8.50	$8.50	($4.50)	-34.6%
2	Distribution Energy Charge	$0.03026	$30.26	$0.03026	$15.13	($15.13)	-50.0%	$0.03026	$15.13	($15.13)	-50.0%
3	Subtotal Distribution		$43.26		$28.13	($15.13)	-35.0%		$23.63	($19.63)	-45.4%
4											
5	LIHEAP Charge	$0.73	$0.73	$0.73	$0.73	$0.00	0.0%	$0.73	$0.73	$0.00	0.0%
6	Transmission Energy Charge	$0.02348	$23.48	$0.02348	$11.74	($11.74)	-50.0%	$0.02348	$11.74	($11.74)	-50.0%
7	Transition Energy Charge	($0.00201)	($2.01)	($0.00201)	($1.01)	$1.00	-49.8%	($0.00201)	($1.01)	$1.00	-49.8%
8	Energy Efficiency Program Charge	$0.00983	$9.83	$0.00983	$4.92	($4.91)	-49.9%	$0.00983	$4.92	($4.91)	-49.9%
9	Renewable Energy Distribution Charge	$0.00232	$2.32	$0.00232	$1.16	($1.16)	-50.0%	$0.00232	$1.16	($1.16)	-50.0%
10	RE Growth Program	$0.17	$0.17	$0.17	$0.17	$0.00	0.0%	$0.17	$0.17	$0.00	0.0%
11	Subtotal Other Delivery Service		$34.52		$17.71	($16.81)	-48.7%		$17.71	($16.81)	-48.7%
12											
13	Standard Offer Charge	$0.10111	$101.11	$0.10111	$50.56	($50.55)	-50.0%	$0.10111	$50.56	($50.55)	-50.0%
14	Renewable Ege Std Charge	$0.00294	$2.94	$0.00294	$1.47	($1.47)	-50.0%	$0.00294	$1.47	($1.47)	-50.0%
15	Subtotal Supply Service		$104.05		$52.03	($52.02)	-50.0%		$52.03	($52.02)	-50.0%
16											
17	Subtotal before GET		$181.83		$97.87	($83.96)	-46.2%		$93.37	($88.46)	-48.6%
18											
19	Gross Earnings Tax	4%	$7.58	4%	$4.08	($3.50)	-46.2%	4%	$3.89	($3.69)	-48.7%
20											
21	Total Bill including GET		$189.41		$101.95	($87.46)	-46.2%		$97.26	($92.15)	-48.7%

******Based on Rates in effect as of July 1, 2015**

Schedule NG-10

Schedule NG - 10

Results of ACOSS and Distribution Revenue [Schedule JAL-1]

X:\2012 neco\General Rate Case (4323)\Compliance Filing (Debt issuance)\Electric ACOS & Rate Design\Attachment 3\Sch JAL 1_3_4-S (Compliance).xls

The Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4323
Compliance Attachment 3B
(Schedule JAL-1)
Page 1 of 1

The Narragansett Electric Company
RESULTS OF ALLOCATED COST OF SERVICE STUDY AND REVENUE ALLOCATION

Line		Total	Residential Rate A-16/ A-60	Small C&I Rate C-06	General C&I Rate G-02	200 kW Demand Rate G-32	3000 kW Demand Rate G-62	Lighting Rates S-10/S-14	Propulsion Rate X-01
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	SECTION 1. SUMMARY OF RESULTS OF ALLOCATED COST OF SERVICE STUDY								
1	Rate Base	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
2									
3	Compliance Rate of Return	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%
4									
5	Return on Rate Base	$40,277	$21,258	$3,911	$5,912	$5,568	$1,401	$2,100	$126
6									
7	Operating Expenses (including taxes)	$219,670	$115,917	$21,697	$31,234	$29,954	$7,436	$12,842	$590
8									
9	Total Distribution Revenue Requirement	$259,947	$137,175	$25,607	$37,146	$35,522	$8,837	$14,942	$717
10									
11	less: Other revenue	$8,163	$3,555	$1,318	$1,593	$935	$477	$269	$15
12									
13	Distribution Rate Revenue Requirement	$251,784	$133,620	$24,289	$35,554	$34,587	$8,360	$14,673	$702
14									
15	Present Total Distribution Revenue	$239,023	$123,070	$25,514	$38,676	$35,317	$5,527	$10,426	$494
16									
17	Present Other Revenue	$8,147	$3,547	$1,317	$1,591	$933	$477	$268	$15
18									
19	Present Distribution Rate Revenue	$230,876	$119,523	$24,198	$37,085	$34,384	$5,050	$10,158	$479
20									
21	Increase/(Decrease) - Total Dist Revenue	$20,924	$14,106	$93	-$1,529	$205	$3,310	$4,516	$223
22									
23	**Percentage Increase/(Decrease)**	8.8%	11.5%	0.4%	-4.0%	0.6%	59.9%	43.3%	45.1%
24									
25	**SECTION 2. COMPLIANCE REVENUE ALLOCATION**								
26									
27	Revenue Requirement @ Equal ROR	$251,784	$133,620	$24,289	$35,554	$34,587	$8,360	$14,673	$702
28									
29	A-60 Rate Design Subsidy	-$6,446	-$6,446						
30	A-60 subsidy Re-allocated on Dist Rev Req Basis	$6,446	$3,421	$622	$910	$886	$214	$376	$18
31	Reallocation of Total A-60 Subsidy	$0	-$3,025	$622	$910	$886	$214	$376	$18
32									
33	Revenue Requirement w/ Low Income Subsidy	$251,784	$130,595	$24,911	$36,464	$35,472	$8,574	$15,048	$720
34	Increase/(Decrease) incl. Low Income Subsidy	$20,908	$11,072	$713	-$621	$1,089	$3,524	$4,891	$241
35									
36	Rev Req (Unconstrained Classes)	$227,442	$130,595	$24,911	$36,464	$35,472			
37	% of Unconstrained Rev Req		57.42%	10.95%	16.03%	15.60%			
38									
39	Increase Constraint- 2 x system average						13.1%	17.5%	17.5%
40	Apply Constraint						$724	$1,825	$86
41									
42	Shortfall from Constrained Classes	-$6,020					-$2,800	-$3,066	-$154
43	Re-allocation of Shortfall on Rev Req	$6,020	$3,457	$659	$965	$939			
44	Energy Efficiency Uncollectibles	-$611	-$243	-$47	-$101	-$180	-$34	-$5	-$2
45	**Revenue Requirement**	$251,173	$133,809	$25,524	$37,328	$36,232	$5,740	$11,977	$564
46									
47	Increase/(Decrease) - Dist Rate Revenue	$20,297	$14,286	$1,326	$243	$1,848	$690	$1,819	$85
48									
49	Increase in Other Revenue	$16	$8	$2	$2	$2	$1	$1	$0
50	Recovery of Egy Eff Uncollectibles thru EE rates	$611	$243	$47	$101	$180	$34	$5	$2
51									
52	Increase/(Decrease) - Total Dist Revenue	$20,924	$14,537	$1,374	$346	$2,030	$725	$1,825	$86
53									
54	**Percentage Increase/(Decrease)**	8.8%	11.8%	5.4%	0.9%	5.7%	13.1%	17.5%	17.5%
55									
56	Return on Rate Base at Compliance Rates	7.17%	7.32%	9.52%	9.44%	9.52%	(6.06%)	(2.02%)	(0.55%)
57									
58									

59	Notes:	
60	Line (1): Compliance Attachment 3A, Page 1, Line (10)	Line (33): Line (27) + Line (31)
61	Line (3): Compliance Attachment 3A, Page 1, Line (32)	Line (34): Line (33) - Line (19)
62	Line (5): Line (1) x Line (3)	Line (36): Line (33) for unconstrained classes
63	Line (7): Compliance Attachment 3A, Page 1, Line (27) + Line (29)	Line (37): Line (36) ÷ Line (36) Total
64	Line (9): Line (5) + Line (7)	Line (39): Constraint: Column (f) Line (23) Total x 1.5, Columns (g) and (h) Line (23) Total x 2
65	Line (11): Compliance Attachment 3A, Page 1, Line (17) + Line (18) + Line (19)	Line(40): Line (15) x Line (39) for constrained classes
66	Line (13): Line (9) - Line (11)	Line (42): Line (40) - Line (34)
67	Line (15): Compliance Attachment 3A, Page 1, Line (1)	Line (43): Line (37) x Line (42) Total for unconstrained classes
68	Line (17): Compliance Attachment 3A, Page 1, Line (2)	Line (44): Energy Efficiency Uncollectibles per Compliance Attachment 1, page 3
69	Line (19): Line (15) - Line (17)	Line (45): Line (33) + Line (42) + Line (43) + Line (44)
70	Line (21): Line (9) - Line (15)	Line (47): Line (45) - Line (19)
71	Line (23): Line (15) ÷ Line (21)	Line (49): Line (11) - Line (17)
72	Line (27): Line (13)	Line (50): Line (44)
73	Line (29): (Compliance Attachment 3D: Page 2, Line (39))	Line (52): Line (47) + Line (49) + Line (50)
74	Line (30): - Line (29) allocated by Distribution Revenue Requirement on Line (13)	Line (54): Line (52) ÷ Line (15)
75	Line (31): Line (29) + Line (30)	Line (56): [Line (45) + Line (11) - Operating Expense - Inc Taxes] ÷ Line (1)

Schedule NG - 11

ACOSS Unit Costs – Compliance Filing in Docket No. 4323

UnitCosts
Unit Costs By I
Tot
HSG-1C (Comp

Narragansett Electric Company
Class ACOS Study (Compliance)
Future Rate Year 2014
Unit Costs By Functional Classification

	Account Description	Units	Total	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
4	Primary Demand		119,353	56,107	10,813	18,648	25,740	6,392	1,086	568
5	Secondary Demand		56,929	34,228	6,597	11,333	3,258	799	651	61
6										
7	Secondary Customer		22,200	8,070	1,075	317	163	38	12,535	3
8	Billing Customer		43,740	31,103	5,650	3,964	1,946	545	513	20
9										
10	**Total revenue requirement**		**259,947**	**137,175**	**25,607**	**37,146**	**35,522**	**8,837**	**14,942**	**717**
11										
12	Total revenue requirement		259,947	137,175	25,607	37,146	35,522	8,837	14,942	717
13										
14	**Unit Costs**	Units								
15	SubTransmission Demand	NCP_at_115 / MW-month	$0.73	$0.67	$0.67	$0.76	$0.84	$0.82	$0.81	$0.55
16										
17	Primary Demand	NCP-Pri / MW-month	$5.10	$5.09	$5.08	$5.10	$5.10	$5.09	$5.86	$4.98
18	Secondary Demand	NCP-Sec / MW-month	$3.51	$3.25	$3.24	$3.27	-	-	$3.68	-
19										
20	Secondary Customer	Customer-Months	$3.70	$1.56	$1.77	$3.16	$12.88	$224.10	$113.98	$223.35
21	Billing Customer	Customer-Months	$7.29	$6.01	$9.31	$39.47	$153.76	$3,241.33	$4.67	$1,675.99
22										
23	**Total By Component**									
24	Demand	NCP_at_115 / MW-month	$7.99	$8.57	$8.55	$8.66	$6.38	$6.34	$9.85	$5.87
25	Customer	Customer-Months	$10.99	$7.57	$11.08	$42.63	$166.64	$3,465.43	$118.65	$1,899.34
26										
27	**Units**									
28	MWh-Generation		8,389,182	3,387,898	648,892	1,407,241	2,305,192	545,045	71,203	23,712
29	NCP_at_115		2,024	953	184	316	436	109	16	10
30	NCP_at_Pri		1,950	919	177	305	420	105	15	9
31	NCP_at_Sec		1,351	879	170	289	0	0	15	0
32	Customer-Months		6,002	5,172	607	100	13	0	110	0

The Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4323
Compliance Attachment 3A
(Schedule HSG-1)
Page 8 of 48

Schedule NG-12

Schedule NG - 12

Proposed Rate Design

The Narragansett Electric Company
Rate Design for Residential Rates A-16

Line		Billing Units: Present Rates	Present Rates	Present Revenue	Billing Units: Proposed Rate Design	Proposed Rates	Proposed Revenue
		(a)	(b)	(c)	(d)	(e)	(f)
1	Revenue Allocation			$133,808,673			$133,808,673
2							
3	Customer Charge:						
4							
5	All bills (A16)	4,669,275	$5.00	$23,346,375			
6	Tier 1: 0 to 250 kWh				649,029	$5.25	$3,407,403
7	Tier 2: 251 to 750 kWh				1,849,033	$8.50	$15,716,780
8	Tier 3: 751 to 1,200 kWh				1,092,610	$13.00	$14,203,935
9	Tier 4: Greater than 1,200 kWh				1,078,603	$18.00	$19,414,845
10	**Customer Charge Revenue**			**23,346,375**	4,669,275		**52,742,963**
11	**Percent of Total Revenue Requirement**			**17.4%**			**39.4%**
12							
13	**All bills (A60)**	502,672	$0.00	**0**	502,672	$0.00	**0**
14							
15	**Remaining Revenue**			**110,462,298**			**81,065,710**
16							
17	Energy-based Charge:						
18	kWh Sales	2,830,141,506	$0.03664	$103,696,385	2,830,141,506	$0.02625	$74,291,215
19	**Percent of Total Revenue Requirement**			**77.5%**			**55.5%**
20							
21	**Distribution Charge Revenue**			**127,042,760**			**127,034,178**
22							
23	Low Income Revenue	291,989,246	$0.02317	6,765,391	291,989,246	$0.02317	6,765,391
24	**Percent of Total Revenue Requirement**			**5.1%**			**5.1%**
25							
26	**Total Revenue**			**$133,808,151**			**$133,799,568**
27							
28	**Revenue in excess of Target**			**($522)**			**($9,104)**
29							
30							

Line				A-16 Charge	A-60 Charge	Difference	Units	Subsidy
31	Subsidy Calculation:		Subsidy Calculation:					
32	Rate A-16 Customer Chg	$5.00						
33	Rate A-60 Customer Chg	$0.00	Tier 1	$5.25	$0.00	$5.25	69,871	$366,825
34	Difference	$5.00	Tier 2	$8.50	$0.00	$8.50	199,058	$1,691,994
35			Tier 3	$13.00	$0.00	$13.00	117,625	$1,529,128
36	Billing Units	502,672	Tier 4	$18.00	$0.00	$18.00	116,117	$2,090,110
37								
38	Subsidy - Customer Chg	$2,513,360	A-60 Customer Charge Subsidy				502,672	$5,678,057
39								
40	Rate A-16 kWh Chg	$0.03664	Docket 4323 Subsidy					$6,446,455
41	Rate A-60 kWh Chg	$0.02317						
42	Difference	$0.01347	Remaining Subsidy					768,398
43								
44	Billing Units	291,989,246	Rate A-60					
45			kWh Charge	$0.02625	$0.02317	$0.00308	291,989,246	899,327
46	Subsidy - kWh Chg	$3,933,095						
47								
48	Total Subsidy	$6,446,455					Total Subsidy	6,577,384
49								

Line		
50	Line Notes:	
51	Line (1): Schedule NG-10 Line (45) Column (b) x 1000	Line (15): Line (1) - Line (10) - Line (13)
52	Line (5) Column (a): per Docket 4323 Compliance schedule JAL-4 page 2	Line (18) Column (e): Line (15) Column (f) divided by line (18) column (d) truncated to 5 decimal poin
53	Line (6) Column (d): 13.9% of Line (5) column (a)	Line (19): Line (18) ÷ Line (26)
54	Line (7) Column (d): 39.6% of Line (5) column (a)	Line (23): Per Docket 4323 Compliance schedule JAL-4 page 2 line (17) column (g)
55	Line (8) Column (d): 23.4% of Line (5) column (a)	Line (24): Line (23) ÷ Line (26)
56	Line (9) Column (d): 23.1% of Line (5) column (a)	Line (26): Line (10) + Line (13) +Line (18) + Line (23)
57	Line (10) Column (f): sum of line (6) through (10)	Line (28): Line (26) - Line (1)
58	Line (11): Line (10) ÷ Line (26)	
59	Line (13): per Docket 4323 Compliance schedule JAL-4 page 2 line 5	

The Narragansett Electric Company
Rate Design for Commercial Rates C-06 (includes C-08)

Line			Billing Units: Present Rates	Present Rates	Present Revenue	Billing Units: Proposed Rate Design	Proposed Rates	Proposed Revenue
			(a)	(b)	(c)	(d)	(e)	(f)
1	Revenue Allocation				$25,523,701			$25,523,701
2								
3	Customer Charge:							
4	Monthly Bills	Metered	599,503	$10.00	$5,995,033			
5	Tier 1: 0 to 100 kWh					93,463	$10.50	$981,362
6	Tier 2: 101 to 700 kWh					209,407	$11.75	$2,460,532
7	Tier 3: 701 to 2,000 kWh					159,468	$17.25	$2,750,823
8	Tier 4: Greater than 2,000 kWh					137,165	$26.00	$3,566,299
9								
10	Monthly Bills	Unmetered	7,152	$6.00	$42,912	7,152	$6.00	$42,912
11								
12	**Customer Charge Revenue**		606,655		**6,037,945**	606,655		**9,801,928**
13	**Percent of Total Revenue Requirement**				**23.7%**			**38.4%**
14								
15	**Remaining Revenue**				**19,485,756**			**15,721,773**
16								
17								
18	Energy-based Charge:							
19	kWh Sales Metered		596,318,721		$19,398,248	596,318,721		$15,647,403
20	Unmetered		1,669,932		$54,323	1,669,932		$43,819
21								
22	**Distribution Charge Revenue**		597,988,653	$0.03253	**19,452,571**	597,988,653	$0.02624	**15,691,222**
23	**Percent of Total Revenue Requirement**				**76.2%**			**61.5%**
24								
25	Over 25 kVA		16,699	$1.85	**30,893**	16,699	$1.85	**30,893**
26	**Percent of Total Revenue Requirement**				**0.1%**			**0.1%**
27								
28	**Total Revenue**				**$25,521,409**			**$25,524,043**
29								
30	**Revenue in excess of Target**				**($2,292)**			**$342**
31								

32 Line Notes:
33 Line (1): Schedule NG-10 Line (45) Column (c) x 1000
34 Line (4) Column (a): per Docket 4323 Compliance schedule JAL-4 Page 3 Line (4)
35 Line (5) Column (d): Line (4) Column (a) x 15.6%
36 Line (6) Column (d): Line (4) Column (a) x 34.9%
37 Line (7) Column (d): Line (4) Column (a) x 35.0%
38 Line (8) Column (d): Line (4) Column (a) x 14.5%
39 Line (10): per Docket 4323 Compliance schedule JAL-4 Page 3 Line (5)
40 Line (12): Sum of lines 4 through 10
41 Line (13): Line (12) ÷ Line (28)

Line (15): Line (1) - Line (12)
Line (19) Column (a): per Docket 4323 Compliance schedule JAL-4 Page 3 line (10
Line (20) Column (a): per Docket 4323 Compliance schedule JAL-4 Page 3 line (11
Line (22) Column (e): Column (f) ÷ Column (d) truncated to 5 decimal places
Line (23): Line (22) ÷ Line (28)
Line (25): per Docket 4323 Compliance schedule JAL-4 Page 4 line (17)
Line (26): Line (25) ÷ Line (28)
Line (28): Line (12) + Line (22) + Line (25)
Line (30): Line (28) - Line (1)

The Narragansett Electric Company
Rate Design for General C&I - Rate G-02

Line		Unit Cost	Billing Units	Current Rates	Revenue	Proposed Rates	Revenue
			(a)	(b)	(c)	(d)	(e)
1	**Section 1: Allocated Cost of Service/Revenue Allocation**						
2							
3	Revenue Allocation				**$37,328,115**		**$37,328,115**
4							
5	Unit Cost Data:						
6							
7	Customer Related Revenue Requirement	$42.63					
8	Percent of Total Revenue Requirement	11.5%					
9							
10	Demand Related Revenue Requirement (kW/mo)	$8.66					
11	Percent of Total Revenue Requirement	88.5%					
12							
13							
14							
15	**Section 2: Proposed Rate Design**						
16							
17	Customer Charge:						
18	Monthly Bills		100,425	$135.00	$13,557,375	$75.00	$7,531,875
19							
20	**Customer Charge Revenue**				**13,557,375**		**7,531,875**
21	**Percent of Total Revenue Requirement**				**36.3%**		**20.2%**
22							
23	Usage-based Charges:						
24							
25	kWh Sales		1,297,414,309	$0.00468	6,071,899	$0.00287	3,723,579
26	**Percent of Total Revenue Requirement**				**16.3%**		**10.0%**
27							
28	Demand Billing Units (in excess of 10kW)		3,656,947.7	$4.85	17,736,196		
29	Demand Billing Units (all kW)		4,661,194.5			$5.60	26,102,689
30	**Percent of Total Revenue Requirement**				**47.5%**		**69.9%**
31							
32	HVD Billing Credit Units		68,986	($0.42)	(28,974)	($0.42)	(28,974)
33							
34	HVM Discount		37,365,470	(0.020%)	(7,473)	(0.020%)	(7,473)
35							
36	**Distribution Charge Revenue**				**23,771,648**		**29,789,821**
37							
38	**Total Revenue**				**$37,329,023**		**$37,321,696**
39							
40	Difference				$908		($6,419)
41							
42							

43 Line Notes:
44 Line (3): Schedule NG-10 Line (45) Column (D) x 1000
45 Line (7): per Docket 4323 Compliance Attachment 3A Page 8, Line 25
46 Line (10): per Docket 4323 Compliance Attachment 3A Page 8, Line 24
47 Line (18), Column (a): per Docket 4323 Compliance schedule JAL-4 Page 4 line (4)
48 Line (20), Column (c): Line 18, Column (a) x Line 18, Column (b)
49 Line (20), Column (e): Line 18, Column (a) x Line 18, Column (d)
50 Line (21): Line (20) ÷ Line (38)
51 Line (25), Column (a): per Docket 4323 Compliance schedule JAL-4 Page 4 line (10)
52 Line (25), Column (d): Line (25) Column (e) ÷ Line (25) Column (a) truncated to 5 decimal places
53 Line (28), Column (a): per Docket 4323 Compliance schecule JAL-4 Page 4 Line (12)

Line (29), Column (a): per Docket 4323 Original Filing, Workpaper JAL-2, page 8, line
Line (29), Column (e): Line (29), Column (a) x Line (29), Column (d)
Line (30), Column (c): Line (28) ÷ Line (38)
Line (30), Column (e): Line (29) ÷ Line (38)
Line (32): per Docket 4323 Compliance schedule JAL-4 Page 4, Line (14)
Line (34), Column (a): Line (20), Column (c) + Line (25), Column (c) + Line (28), Column (c)
Line (36): Line (25) + Line (28) + Line (32) + Line (34)
Line (38): Line (20) + Line (36)
Line (40): Line (38) - Line (1)

The Narragansett Electric Company
Rate Design for Large Demand - Rate G-32 (includes Rate G-62 and Back-up Rates B-32 & B-62)

Line			Unit Cost	Billing Units	Current Rates	Revenue	Billing Units	Proposed Rates	Revenue
				(a)	(b)	(c)	(d)	(e)	(f)
1	**Section 1: Allocated Cost or Service/Revenue Allocation**								
2									
3	Revenue Allocation					**$41,971,681**			**$41,971,681**
4									
5	Unit Cost Data:								
6									
7	Customer Related Revenue Requirement	G32	$166.64						
8	Customer Related Revenue Requirement	G62	$3,465.43						
9	Percent of Total Revenue Requirement		6.4%						
10									
11	Demand Related Revenue Requirement (kW/mo)	G32	$6.38						
12	Demand Related Revenue Requirement (kW/mo)	G62	$6.34						
13	Percent of Total Revenue Requirement		93.6%						
14									
15									
16									
17	**Section 2: Proposed Rate Design**								
18	Customer Charge:								
19	Monthly Bills	B-32		60	$825.00	$49,500			
20		G-32		12,595	$825.00	$10,390,875			
21		B-62		24	$17,000.00	$408,000			
22		G-62		144	$17,000.00	$2,448,000	12,823	$215.00	$2,756,945
23	**Customer Charge Revenue**			12,823		**$13,296,375**	12,823		**2,756,945**
24	**Percent of Total Revenue Requirement**					**31.7%**			**6.6%**
25									
26	Energy-based Charge:								
27	kWh Sales	B-32 Supplemental		6,104,280	$0.00551	$33,635			
28	kWh Sales	G-32		2,215,125,443	$0.00551	$12,205,341			
29	kWh Sales	B-62 Supplemental		75,685,416	$0.00000	$0			
30	kWh Sales	G-62		449,506,993	$0.00000	$0	2,746,422,132	$0.00230	$6,316,771
31				2,746,422,132		**$12,238,976**	2,746,422,132		**$6,316,771**
32	**Percent of Total Revenue Requirement**					**29.2%**			**15.1%**
33									
34	Demand Charge (All)								
35	Demand Billing Units (200 kW Demand)	B-32 Back-up		1,084	$0.42	$455	1,084	$0.53	$572
36	Demand Billing Units (200 kW Demand)	B-32 Supplemental		18,711	$3.70	$69,231	18,711	$4.50	$84,200
37	Demand Billing Units (200 kW Demand)	G-32		3,724,034	$3.70	$13,778,926	6,243,005	$4.50	$28,093,523
38	Demand Billing Units (3000 kW Demand)	B-62 Back-up		85,819	($0.02)	-$1,716	85,819	$0.53	$45,313
39	Demand Billing Units (3000 kW Demand)	B-62 Supplemental		146,085	$2.99	$436,795	146,085	$4.50	$657,384
40	Demand Billing Units (3000 kW Demand)	G-62		1,009,195	$2.99	$3,017,494	1,009,195	$4.50	$4,541,379
41				4,984,929		**$17,301,184**	7,503,900		**$33,422,370**
42	**Percent of Total Revenue Requirement**					**41.2%**			**79.6%**
43									
44	HVD Billing Credit Units	B-32		6,665	($0.42)	($2,799)	6,665	($0.42)	($2,799)
45		G-32		1,625,054	($0.42)	($682,523)	1,625,054	($0.42)	($682,523)
46		B-62		58,127	($0.42)	($24,413)	58,127	($0.42)	($24,413)
47		G-62		948,442	($0.42)	($398,346)	948,442	($0.42)	($398,346)
48				2,638,288		**($1,108,081)**	2,638,288		**($1,108,081)**
49									
50	HVM Discount	G-32		$37,458,796	-0.5%	($176,056)	$37,458,796	-0.5%	($187,294)
51		G-62		$6,308,573	-2.3%	($142,574)	$6,308,573	-2.3%	($145,097)
52						**($318,630)**			**($332,391)**
53									
54	Second Feeder Service	G-32		293,675	$3.17	**$930,950**	293,675	$3.17	**$930,950**
55									
56	**Total Revenue**					**$42,340,774**			**$41,986,564**
57									
58	**Difference**					**$369,093**			**$14,883**
59									
60	**Design of Back-up Demand Charge**								
61									
62	Revenue Requirement (Demand and Energy Based Charges)								**$39,693,256**
63									
64	Demand billing Units (Supplemental and G-32/62 Demands)								**7,503,900**
65									
66	Back-up Demand Charge before 90% Discount								$5.28
67									

Line		
68	Line Notes:	
69	Line (1): Schedule NG-11 Line (45) Column (e) x 1000 + Column (f) x 1000	Line (40), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (15)
70	Line (19), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (4)	Line (41): Sum of lines 35 through 40
71	Line (20), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (5)	Line (42): Line (41) ÷ Line (56)
72	Line (21), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (4)	Line (44), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (18)
73	Line (22), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (5)	Line (45), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (19)
74	Line (23): Sum of Lines 19 through 22	Line (46), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (18)
75	Line (24): Line (23)÷ Line (56)	Line (47), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (19)
76	Line (27), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (9)	Line (48): Sum of lines 44 through 47
77	Line (28), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (10)	Line (50), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line 22
78	Line (29), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (9)	Line (51), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line 22
79	Line (30), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (10)	Line (52): Line (50) + Line (51)
80	Line (31): Sum of lines 27 through 30	Line (54): per Docket 4323 compliance schedule JAL-4, page 5, line 24
81	Line (32): Line (31) ÷ Line (56)	Line (56): Line (8) + Line (16) + Line (25) + Line (32) + Line (36) + Line (38)
82	Line (35), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (13)	Line (58): Line (56) - Line (3)
83	Line (36), Column (a): per Docket 4323 compliance schedule JAL-4, page 5, line (14)	Line (62), column (f): Line (31), Column (f) + Line (36), column (f) + Line (37), column (f)
84	Line (37), Column (a): per Docket 4323 original filing, Workpaper JAL-2, page 8, line (8)	+ Line (39), column (f) + Line (40), column (f)
85	Line (38), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (13)	Line (64), column (f): Line (41), column (d)
86	Line (39), Column (a): per Docket 4323 compliance schedule JAL-4, page 6, line (14)	Line (66), column (f): Line (62), column f ÷ Line (64), column (f)

Schedule NG-13

Schedule NG - 13

Typical Bills

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Average Monthly kWh	Maximum Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers	Percentage of Customers in Tier
0	0 - 250	$6.15	$0.00	$6.15	$6.41	$0.00	$6.41	$0.26	4.2%	0.5%	
45		$14.51	$4.88	$9.63	$14.28	$4.88	$9.40	($0.23)	-1.6%	2.7%	
88		$22.49	$9.54	$12.95	$21.80	$9.54	$12.26	($0.69)	-3.1%	2.7%	
125		$29.37	$13.55	$15.82	$28.27	$13.55	$14.72	($1.10)	-3.7%	2.7%	
162		$36.24	$17.56	$18.68	$34.75	$17.56	$17.19	($1.49)	-4.1%	2.7%	
250		$52.59	$27.10	$25.49	$50.14	$27.10	$23.04	($2.45)	-4.7%	2.7%	13.9%
225	251 - 750	$47.94	$24.39	$23.55	$49.15	$24.39	$24.76	$1.21	2.5%	6.6%	
279		$57.97	$30.24	$27.73	$58.60	$30.24	$28.36	$0.63	1.1%	6.6%	
333		$68.00	$36.09	$31.91	$68.04	$36.09	$31.95	$0.04	0.1%	6.7%	
391		$78.78	$42.38	$36.40	$78.19	$42.38	$35.81	($0.59)	-0.7%	6.6%	
500		$99.02	$54.19	$44.83	$97.25	$54.19	$43.06	($1.77)	-1.8%	6.6%	
750		$145.46	$81.29	$64.17	$140.99	$81.29	$59.70	($4.47)	-3.1%	6.6%	39.6%
500	751 - 1200	$99.02	$54.19	$44.83	$101.94	$54.19	$47.75	$2.92	2.9%	3.9%	
561		$110.35	$60.80	$49.55	$112.61	$60.80	$51.81	$2.26	2.0%	3.9%	
621		$121.50	$67.31	$54.19	$123.11	$67.31	$55.80	$1.61	1.3%	3.9%	
683		$133.02	$74.03	$58.99	$133.96	$74.03	$59.93	$0.94	0.7%	3.9%	
765		$148.24	$82.91	$65.33	$148.29	$82.91	$65.38	$0.05	0.0%	3.9%	
1,200		$229.04	$130.06	$98.98	$224.39	$130.06	$94.33	($4.65)	-2.0%	3.9%	23.5%
770	GT 1200	$149.18	$83.46	$65.72	$154.38	$83.46	$70.92	$5.20	3.5%	3.8%	
901		$173.51	$97.66	$75.85	$177.30	$97.66	$79.64	$3.79	2.2%	3.8%	
1,024		$196.36	$110.99	$85.37	$198.82	$110.99	$87.83	$2.46	1.3%	3.8%	
1,192		$227.56	$129.20	$98.36	$228.21	$129.20	$99.01	$0.65	0.3%	3.8%	
1,505		$285.70	$163.12	$122.58	$282.95	$163.12	$119.83	($2.75)	-1.0%	3.8%	
10,000		$1,863.64	$1,083.85	$779.79	$1,768.95	$1,083.85	$685.10	($94.69)	-5.1%	3.8%	23.0%

Present Rates			Proposed Rates		
Customer Charge (1)		$5.00	Customer Charge - Tier 1 (0-250 kWh) (2)		$5.25
			Customer Charge - Tier 2 (251-750kWh) (2)		$8.50
			Customer Charge - Tier 3 (751-1200kWh) (2)		$13.00
			Customer Charge - Tier 4 (Greater than 1200 kWh) (2)		$18.00
RE Growth Factor		$0.17	RE Growth Factor		$0.17
LIHEAP Charge		$0.73	LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02348	Transmission Energy Charge	kWh x	$0.02348
Distribution Energy Charge (3)	kWh x	$0.04065	Distribution Energy Charge (4)	kWh x	$0.03026
Transition Energy Charge	kWh x	($0.00201)	Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983	Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232	Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.10405	Standard Offer Charge	kWh x	$0.10405

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): includes the current Base Distribution Charge of 3.664¢/kWh, the current CapEx factor of 0.153¢/kWh, the current O&M factor of 0.183¢/kWh, the current CapEx Reconciliation Factor of (0.021)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (4): includes the proposed Base Distribution Charge of 2.625¢/kWh, the current CapEx factor of 0.153¢/kWh, the current O&M factor of 0.183¢/kWh, the current CapEx Reconciliation Factor of (0.021)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

Average Monthly kWh	Maximum Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers	Percentage of Customers in Tier
0	0 - 100	$11.45	$0.00	$11.45	$11.97	$0.00	$11.97	$0.52	4.5%	2.9%	
5		$12.27	$0.47	$11.80	$12.76	$0.47	$12.29	$0.49	4.0%	2.4%	
16		$14.07	$1.50	$12.57	$14.49	$1.50	$12.99	$0.42	3.0%	2.7%	
29		$16.20	$2.71	$13.49	$16.53	$2.71	$13.82	$0.33	2.0%	2.6%	
46		$18.99	$4.31	$14.68	$19.21	$4.31	$14.90	$0.22	1.2%	2.5%	
100		$27.84	$9.36	$18.48	$27.71	$9.36	$18.35	($0.13)	-0.5%	2.5%	15.6%
96	101-700	$27.19	$8.99	$18.20	$28.39	$8.99	$19.40	$1.20	4.4%	5.8%	
143		$34.89	$13.38	$21.51	$35.77	$13.38	$22.39	$0.88	2.5%	5.9%	
207		$45.38	$19.37	$26.01	$45.85	$19.37	$26.48	$0.47	1.0%	5.8%	
291		$59.16	$27.24	$31.92	$59.08	$27.24	$31.84	($0.08)	-0.1%	5.8%	
401		$77.19	$37.53	$39.66	$76.39	$37.53	$38.86	($0.80)	-1.0%	5.8%	
700		$126.22	$65.52	$60.70	$123.45	$65.52	$57.93	($2.77)	-2.2%	5.8%	34.9%
483	701-2000	$90.64	$45.21	$45.43	$95.03	$45.21	$49.82	$4.39	4.8%	4.4%	
619		$112.93	$57.93	$55.00	$116.42	$57.93	$58.49	$3.49	3.1%	4.4%	
736		$132.12	$68.89	$63.23	$134.85	$68.89	$65.96	$2.73	2.1%	4.4%	
887		$156.87	$83.02	$73.85	$158.61	$83.02	$75.59	$1.74	1.1%	4.4%	
1,122		$195.40	$105.01	$90.39	$195.60	$105.01	$90.59	$0.20	0.1%	4.4%	
2,000		$339.35	$187.19	$152.16	$333.79	$187.19	$146.60	($5.56)	-1.6%	4.5%	26.6%
1,428	GT 2000	$245.56	$133.65	$111.91	$252.87	$133.65	$119.22	$7.31	3.0%	3.8%	
1,834		$312.13	$171.65	$140.48	$316.78	$171.65	$145.13	$4.65	1.5%	3.8%	
2,292		$387.22	$214.52	$172.70	$388.87	$214.52	$174.35	$1.65	0.4%	3.8%	
2,996		$502.64	$280.41	$222.23	$499.68	$280.41	$219.27	($2.96)	-0.6%	3.8%	
4,249		$708.06	$397.68	$310.38	$696.89	$397.68	$299.21	($11.17)	-1.6%	3.8%	
10,000		$1,650.93	$935.94	$714.99	$1,602.08	$935.94	$666.14	($48.85)	-3.0%	3.8%	22.9%

Present Rates			Proposed Rates		
Customer Charge (1)		$10.00	Customer Charge - Tier 1 (0-100 kWh) (2)		$10.50
			Customer Charge - Tier 2 (101-700 kWh) (2)		$11.75
			Customer Charge - Tier 3 (701-2000 kWh) (2)		$17.25
			Customer Charge - Tier 4 (Greater than 2000 kWh) (2)		$26.00
RE Growth Factor		$0.26	RE Growth Factor		$0.26
LIHEAP Charge		$0.73	LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02072	Transmission Energy Charge	kWh x	$0.02072
Distribution Energy Charge (3)	kWh x	$0.03668	Distribution Energy Charge (4)	kWh x	$0.03039
Transition Energy Charge	kWh x	($0.00201)	Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983	Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232	Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985	Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): includes the current Base Distribution Charge of 3.253¢/kWh, the current CapEx factor of 0.150¢/kWh, the current O&M factor of 0.200¢/kWh, the current CapEx Reconciliation Factor of (0.021)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (4): includes the proposed Base Distribution Charge of 2.624¢/kWh, the current CapEx factor of 0.150¢/kWh, the current O&M factor of 0.200¢/kWh, the current CapEx Reconciliation Factor of (0.021)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$743.85	$374.38	$369.47	$743.91	$374.38	$369.53	$0.06	0.0%
50	10,000	$1,725.41	$935.94	$789.47	$1,737.60	$935.94	$801.66	$12.19	0.7%
100	20,000	$3,361.35	$1,871.88	$1,489.47	$3,393.74	$1,871.88	$1,521.86	$32.39	1.0%
150	30,000	$4,997.28	$2,807.81	$2,189.47	$5,049.88	$2,807.81	$2,242.07	$52.60	1.1%

Present Rates

Customer Charge (1)		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW (3)	kW x	$5.23
Distribution Energy Charge (5)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Proposed Customer Charge (2)		$75.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Proposed Distribution Demand Charge- all kW (4	kW x	$5.98
Distribution Energy Charge (6)	kWh x	$0.00506
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): Current Distribution Demand Charge - in excess of 10kW

Note (4): Proposed Distribution Demand Charge - all kW

Note (5): includes the current Base Distribution Energy Charge of 0.468¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.287¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$985.09	$561.56	$423.53	$981.38	$561.56	$419.82	($3.71)	-0.4%
50	15,000	$2,328.54	$1,403.91	$924.63	$2,331.30	$1,403.91	$927.39	$2.76	0.1%
100	30,000	$4,567.59	$2,807.81	$1,759.78	$4,581.13	$2,807.81	$1,773.32	$13.54	0.3%
150	45,000	$6,806.66	$4,211.72	$2,594.94	$6,830.98	$4,211.72	$2,619.26	$24.32	0.4%

Present Rates

Customer Charge (1)		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW (3	kW x	$5.23
Distribution Energy Charge (5)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Proposed Customer Charge (2)		$75.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Proposed Distribution Demand Charge- all kW (4)	kW x	$5.98
Distribution Energy Charge (6)	kWh x	$0.00506
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): Current Distribution Demand Charge - in excess of 10kW

Note (4): Proposed Distribution Demand Charge - all kW

Note (5): includes the current Base Distribution Energy Charge of 0.468¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.287¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,226.34	$748.75	$477.59	$1,218.86	$748.75	$470.11	($7.48)	-0.6%
50	20,000	$2,931.66	$1,871.88	$1,059.78	$2,924.99	$1,871.88	$1,053.11	($6.67)	-0.2%
100	40,000	$5,773.84	$3,743.75	$2,030.09	$5,768.53	$3,743.75	$2,024.78	($5.31)	-0.1%
150	60,000	$8,616.04	$5,615.63	$3,000.41	$8,612.08	$5,615.63	$2,996.45	($3.96)	0.0%

Present Rates

Customer Charge (1)		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW (3)	kW x	$5.23
Distribution Energy Charge (5)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Proposed Customer Charge (2)		$75.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Proposed Distribution Demand Charge- all kW (4)	kW x	$5.98
Distribution Energy Charge (6)	kWh x	$0.00506
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): Current Distribution Demand Charge - in excess of 10kW

Note (4): Proposed Distribution Demand Charge - all kW

Note (5): includes the current Base Distribution Energy Charge of 0.468¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.287¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,467.60	$935.94	$531.66	$1,456.35	$935.94	$520.41	($11.25)	-0.8%
50	25,000	$3,534.78	$2,339.84	$1,194.94	$3,518.68	$2,339.84	$1,178.84	($16.10)	-0.5%
100	50,000	$6,980.10	$4,679.69	$2,300.41	$6,955.93	$4,679.69	$2,276.24	($24.17)	-0.3%
150	75,000	$10,425.41	$7,019.53	$3,405.88	$10,393.17	$7,019.53	$3,373.64	($32.24)	-0.3%

Present Rates

Customer Charge (1)		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW (3)	kW x	$5.23
Distribution Energy Charge (5)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Proposed Customer Charge (2)		$75.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Proposed Distribution Demand Charge- all kW (4)	kW x	$5.98
Distribution Energy Charge (6)	kWh x	$0.00506
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): Current Distribution Demand Charge - in excess of 10kW

Note (4): Proposed Distribution Demand Charge - all kW

Note (5): includes the current Base Distribution Energy Charge of 0.468¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.287¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,708.85	$1,123.13	$585.72	$1,693.83	$1,123.13	$570.70	($15.02)	-0.9%
50	30,000	$4,137.90	$2,807.81	$1,330.09	$4,112.38	$2,807.81	$1,304.57	($25.52)	-0.6%
100	60,000	$8,186.35	$5,615.63	$2,570.72	$8,143.33	$5,615.63	$2,527.70	($43.02)	-0.5%
150	90,000	$12,234.78	$8,423.44	$3,811.34	$12,174.26	$8,423.44	$3,750.82	($60.52)	-0.5%

Present Rates

Customer Charge (1)		$135.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Distribution Demand Charge-xcs 10 kW (3)	kW x	$5.23
Distribution Energy Charge (5)	kWh x	$0.00687
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Proposed Rates

Proposed Customer Charge (2)		$75.00
RE Growth Factor		$2.46
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00894
Proposed Distribution Demand Charge- all k	kW x	$5.98
Distribution Energy Charge (6)	kWh x	$0.00506
Proposed Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08985

Note (1): Current Customer Charge

Note (2): Proposed Tiered Customer Charge

Note (3): Current Distribution Demand Charge - in excess of 10kW

Note (4): Proposed Distribution Demand Charge - all kW

Note (5): includes the current Base Distribution Energy Charge of 0.468¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.287¢/kWh, the current O&M factor of 0.148¢/kWh, the current CapEx Reconciliation Factor of (0.015)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,382.83	$2,686.67	$2,696.16	$5,634.49	$2,686.67	$2,947.82	$251.66	4.7%
750	150,000	$20,118.24	$10,075.00	$10,043.24	$20,460.43	$10,075.00	$10,385.43	$342.19	1.7%
1,000	200,000	$26,816.15	$13,433.33	$13,382.82	$27,199.49	$13,433.33	$13,766.16	$383.34	1.4%
1,500	300,000	$40,211.99	$20,150.00	$20,061.99	$40,677.61	$20,150.00	$20,527.61	$465.62	1.2%
2,500	500,000	$67,003.65	$33,583.33	$33,420.32	$67,633.86	$33,583.33	$34,050.53	$630.21	0.9%

<u>Present Rates</u>

Customer Charge (1)		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW (3)	kW x	$4.10
Distribution Energy Charge (5)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Proposed Distribution Demand Charge - all kW (4)	kW x	$4.90
Distribution Energy Charge (6)	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $3.70/kW > 200 kW, and the current CapEx Factor Charge of $0.40/kW > 200 kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW (all kW), and the current CapEx Factor Charge of $0.40/kW (all kW)

Note (5): includes the current Base Distribution Energy Charge of 0.551¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.230¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,280.74	$4,030.00	$3,250.74	$7,465.53	$4,030.00	$3,435.53	$184.79	2.5%
750	225,000	$27,235.43	$15,112.50	$12,122.93	$27,326.83	$15,112.50	$12,214.33	$91.40	0.3%
1,000	300,000	$36,305.74	$20,150.00	$16,155.74	$36,354.70	$20,150.00	$16,204.70	$48.96	0.1%
1,500	450,000	$54,446.36	$30,225.00	$24,221.36	$54,410.43	$30,225.00	$24,185.43	($35.93)	-0.1%
2,500	750,000	$90,727.61	$50,375.00	$40,352.61	$90,521.89	$50,375.00	$40,146.89	($205.72)	-0.2%

Present Rates			Proposed Rates		
Customer Charge (1)		$825.00	Customer Charge (2)		$215.00
RE Growth Factor		$17.78	RE Growth Factor		$17.78
LIHEAP Charge		$0.73	LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40	Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930	Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW (3)	kW x	$4.10	Proposed Distribution Demand Charge - all k	kW x	$4.90
Distribution Energy Charge (5)	kWh x	$0.00718	Distribution Energy Charge (6)	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)	Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983	Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232	Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448	Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $3.70/kW > 200 kW, and the current CapEx Factor Charge of $0.40/kW > 200 kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW (all kW), and the current CapEx Factor Charge of $0.40/kW (all kW)

Note (5): includes the current Base Distribution Energy Charge of 0.551¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.230¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$9,178.65	$5,373.33	$3,805.32	$9,296.57	$5,373.33	$3,923.24	$117.92	1.3%
750	300,000	$34,352.61	$20,150.00	$14,202.61	$34,193.24	$20,150.00	$14,043.24	($159.37)	-0.5%
1,000	400,000	$45,795.33	$26,866.67	$18,928.66	$45,509.91	$26,866.67	$18,643.24	($285.42)	-0.6%
1,500	600,000	$68,680.74	$40,300.00	$28,380.74	$68,143.24	$40,300.00	$27,843.24	($537.50)	-0.8%
2,500	1,000,000	$114,451.58	$67,166.67	$47,284.91	$113,409.91	$67,166.67	$46,243.24	($1,041.67)	-0.9%

Present Rates

Customer Charge (1)		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW (3)	kW x	$4.10
Distribution Energy Charge (5)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Proposed Distribution Demand Charge - all k	kW x	$4.90
Distribution Energy Charge (6)	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $3.70/kW > 200 kW, and the current CapEx Factor Charge of $0.40/kW > 200 kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW (all kW), and the current CapEx Factor Charge of $0.40/kW (all kW)

Note (5): includes the current Base Distribution Energy Charge of 0.551¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.230¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,076.58	$6,716.67	$4,359.91	$11,127.62	$6,716.67	$4,410.95	$51.04	0.5%
750	375,000	$41,469.80	$25,187.50	$16,282.30	$41,059.65	$25,187.50	$15,872.15	($410.15)	-1.0%
1,000	500,000	$55,284.90	$33,583.33	$21,701.57	$54,665.11	$33,583.33	$21,081.78	($619.79)	-1.1%
1,500	750,000	$82,915.11	$50,375.00	$32,540.11	$81,876.05	$50,375.00	$31,501.05	($1,039.06)	-1.3%
2,500	1,250,000	$138,175.53	$83,958.33	$54,217.20	$136,297.92	$83,958.33	$52,339.59	($1,877.61)	-1.4%

Present Rates

Customer Charge (1)		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW (3)	kW x	$4.10
Distribution Energy Charge (5)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Proposed Distribution Demand Charge - all k	kW x	$4.90
Distribution Energy Charge (6)	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $3.70/kW > 200 kW, and the current CapEx Factor Charge of $0.40/kW > 200 kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW (all kW), and the current CapEx Factor Charge of $0.40/kW (all kW)

Note (5): includes the current Base Distribution Energy Charge of 0.551¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.230¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$12,974.49	$8,060.00	$4,914.49	$12,958.66	$8,060.00	$4,898.66	($15.83)	-0.1%
750	450,000	$48,586.99	$30,225.00	$18,361.99	$47,926.05	$30,225.00	$17,701.05	($660.94)	-1.4%
1,000	600,000	$64,774.49	$40,300.00	$24,474.49	$63,820.32	$40,300.00	$23,520.32	($954.17)	-1.5%
1,500	900,000	$97,149.49	$60,450.00	$36,699.49	$95,608.86	$60,450.00	$35,158.86	($1,540.63)	-1.6%
2,500	1,500,000	$161,899.49	$100,750.00	$61,149.49	$159,185.95	$100,750.00	$58,435.95	($2,713.54)	-1.7%

Present Rates

Customer Charge (1)		$825.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge - > 200 kW (3)	kW x	$4.10
Distribution Energy Charge (5)	kWh x	$0.00718
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Proposed Distribution Demand Charge - all k	kW x	$4.90
Distribution Energy Charge (6)	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $3.70/kW > 200 kW, and the current CapEx Factor Charge of $0.40/kW > 200 kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW (all kW), and the current CapEx Factor Charge of $0.40/kW (all kW)

Note (5): includes the current Base Distribution Energy Charge of 0.551¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Note (6): includes the proposed Base Distribution Energy Charge of 0.230¢/kWh, the current O&M factor of 0.090¢/kWh, the current CapEx Reconciliation Factor of (0.009)¢/kWh, the current O&M Reconciliation Factor of (0.005)¢/kWh, and the current RDM Reconciliation Factor of 0.091¢

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	600,000	$94,108.13	$40,300.00	$53,808.13	$81,111.99	$40,300.00	$40,811.99	($12,996.14)	-13.8%
5,000	1,000,000	$144,799.80	$67,166.67	$77,633.13	$135,024.49	$67,166.67	$67,857.82	($9,775.31)	-6.8%
7,500	1,500,000	$208,164.38	$100,750.00	$107,414.38	$202,415.11	$100,750.00	$101,665.11	($5,749.27)	-2.8%
10,000	2,000,000	$271,528.96	$134,333.33	$137,195.63	$269,805.74	$134,333.33	$135,472.41	($1,723.22)	-0.6%
20,000	4,000,000	$524,987.30	$268,666.67	$256,320.63	$539,368.24	$268,666.67	$270,701.57	$14,380.94	2.7%

<u>Present Rates</u>

Customer Charge (1)		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge (3)	kW x	$3.54
Distribution Energy Charge	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge (4)	kW x	$4.90
Distribution Energy Charge	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $2.99/kW, the current CapEx Factor Charge of $0.23/kW, and the current O&M Factor Charge of $0.32/kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW, the current CapEx Factor Charge for G32 of $0.40/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$121,564.38	$60,450.00	$61,114.38	$108,577.61	$60,450.00	$48,127.61	($12,986.77)	-10.7%
5,000	1,500,000	$190,560.21	$100,750.00	$89,810.21	$180,800.53	$100,750.00	$80,050.53	($9,759.68)	-5.1%
7,500	2,250,000	$276,805.00	$151,125.00	$125,680.00	$271,079.18	$151,125.00	$119,954.18	($5,725.82)	-2.1%
10,000	3,000,000	$363,049.79	$201,500.00	$161,549.79	$361,357.82	$201,500.00	$159,857.82	($1,691.97)	-0.5%
20,000	6,000,000	$708,028.96	$403,000.00	$305,028.96	$722,472.41	$403,000.00	$319,472.41	$14,443.45	2.0%

Present Rates

Customer Charge (1)		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge (3)	kW x	$3.54
Distribution Energy Charge	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge (4)	kW x	$4.90
Distribution Energy Charge	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $2.99/kW, the current CapEx Factor Charge of $0.23/kW, and the current O&M Factor Charge of $0.32/kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW, the current CapEx Factor Charge for G32 of $0.40/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,200,000	$149,020.63	$80,600.00	$68,420.63	$136,043.24	$80,600.00	$55,443.24	($12,977.39)	-8.7%
5,000	2,000,000	$236,320.62	$134,333.33	$101,987.29	$226,576.57	$134,333.33	$92,243.24	($9,744.05)	-4.1%
7,500	3,000,000	$345,445.63	$201,500.00	$143,945.63	$339,743.24	$201,500.00	$138,243.24	($5,702.39)	-1.7%
10,000	4,000,000	$454,570.63	$268,666.67	$185,903.96	$452,909.91	$268,666.67	$184,243.24	($1,660.72)	-0.4%
20,000	8,000,000	$891,070.62	$537,333.33	$353,737.29	$905,576.57	$537,333.33	$368,243.24	$14,505.95	1.6%

<u>Present Rates</u>

Customer Charge (1)		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge (3)	kW x	$3.54
Distribution Energy Charge	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

<u>Proposed Rates</u>

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge (4)	kW x	$4.90
Distribution Energy Charge	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $2.99/kW, the current CapEx Factor Charge of $0.23/kW, and the current O&M Factor Charge of $0.32/kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW, the current CapEx Factor Charge for G32 of $0.40/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,500,000	$176,476.88	$100,750.00	$75,726.88	$163,508.86	$100,750.00	$62,758.86	($12,968.02)	-7.3%
5,000	2,500,000	$282,081.05	$167,916.67	$114,164.38	$272,352.62	$167,916.67	$104,435.95	($9,728.43)	-3.4%
7,500	3,750,000	$414,086.25	$251,875.00	$162,211.25	$408,407.30	$251,875.00	$156,532.30	($5,678.95)	-1.4%
10,000	5,000,000	$546,091.46	$335,833.33	$210,258.13	$544,461.99	$335,833.33	$208,628.66	($1,629.47)	-0.3%
20,000	10,000,000	$1,074,112.30	$671,666.67	$402,445.63	$1,088,680.74	$671,666.67	$417,014.07	$14,568.44	1.4%

Present Rates

Customer Charge (1)		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge (3)	kW x	$3.54
Distribution Energy Charge	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge (4)	kW x	$4.90
Distribution Energy Charge	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $2.99/kW, the current CapEx Factor Charge of $0.23/kW, and the current O&M Factor Charge of $0.32/kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW, the current CapEx Factor Charge for G32 of $0.40/kW

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	Monthly	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,800,000	$203,933.13	$120,900.00	$83,033.13	$190,974.49	$120,900.00	$70,074.49	($12,958.64)	-6.4%
5,000	3,000,000	$327,841.46	$201,500.00	$126,341.46	$318,128.66	$201,500.00	$116,628.66	($9,712.80)	-3.0%
7,500	4,500,000	$482,726.88	$302,250.00	$180,476.88	$477,071.36	$302,250.00	$174,821.36	($5,655.52)	-1.2%
10,000	6,000,000	$637,612.29	$403,000.00	$234,612.29	$636,014.07	$403,000.00	$233,014.07	($1,598.22)	-0.3%
20,000	12,000,000	$1,257,153.96	$806,000.00	$451,153.96	$1,271,784.91	$806,000.00	$465,784.91	$14,630.95	1.2%

Present Rates

Customer Charge (1)		$17,000.00
RE Growth Factor		$347.07
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.22
Transmission Energy Charge	kWh x	$0.01247
Distribution Demand Charge (3)	kW x	$3.54
Distribution Energy Charge	kWh x	$0.00077
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kWh x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Proposed Rates

Customer Charge (2)		$215.00
RE Growth Factor		$17.78
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00930
Distribution Demand Charge (4)	kW x	$4.90
Distribution Energy Charge	kWh x	$0.00397
Transition Energy Charge	kWh x	($0.00201)
Energy Efficiency Program Charge	kWh x	$0.00983
Renewable Energy Distribution Charge	kW x	$0.00232
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.06448

Note (1): Current Customer Charge

Note (2): Proposed Customer Charge

Note (3): includes the current Distribution Demand Charge of $2.99/kW, the current CapEx Factor Charge of $0.23/kW, and the current O&M Factor Charge of $0.32/kW

Note (4): includes the proposed Distribution Demand Charge of $4.50/kW, the current CapEx Factor Charge for G32 of $0.40/kW

Schedule NG-14

Schedule NG - 14

Individual Customer Bill Impacts

Rate Code G02
Individual Customer Impacts

	Number of accounts	% of Customers	Average Annual Change	Average Monthly Change	Min % change	Max % change
	135	1.7%	($100.33)	($8.36)	-1.9%	-1.1%
	3918	50.6%	($78.43)	($6.54)	-1.0%	-0.1%
	513	6.6%	($0.66)	($0.05)	0.0%	0.0%
	2531	32.7%	$130.42	$10.87	0.1%	1.0%
	496	6.4%	$405.16	$33.76	1.1%	2.0%
	101	1.3%	$642.59	$53.55	2.1%	3.0%
	39	0.5%	$770.02	$64.17	3.1%	3.9%
	8	0.1%	$930.51	$77.54	4.1%	4.9%
	3	0.0%	$1,211.94	$101.00	5.2%	5.4%
	3	0.0%	$3,334.97	$277.91	6.1%	6.7%
TOTAL	7,747	100.0%	$42.03	$3.50	-1.9%	6.7%

Rate Code B/G32
Individual Customer Impacts

	Number of accounts	% of Customers	Average Annual Change	Average Monthly Change	Min % change	Max % change
	6	0.6%	($6,200.62)	($516.72)	-46.3%	-20.8%
	17	1.7%	($5,101.35)	($425.11)	-15.5%	-10.1%
	22	2.2%	($3,603.06)	($300.25)	-10.0%	-5.3%
	16	1.6%	($3,051.46)	($254.29)	-5.0%	-4.1%
	18	1.8%	($2,430.33)	($202.53)	-4.0%	-3.1%
	12	1.2%	($1,902.08)	($158.51)	-2.9%	-2.1%
	103	10.2%	($8,351.88)	($695.99)	-2.0%	-1.1%
	311	30.7%	($2,051.53)	($170.96)	-1.0%	-0.1%
	35	3.5%	$8.35	$0.70	0.0%	0.0%
	239	23.6%	$803.20	$66.93	0.1%	1.0%
	114	11.2%	$2,006.44	$167.20	1.1%	2.0%
	54	5.3%	$2,842.81	$236.90	2.1%	3.0%
	31	3.1%	$3,296.94	$274.75	3.1%	4.0%
	14	1.4%	$3,921.68	$326.81	4.1%	5.0%
	21	2.1%	$5,716.64	$476.39	5.2%	9.7%
	1	0.1%	$3,742.85	$311.90	10.9%	10.9%
TOTAL	1014	100.0%	-$948.18	-$79.01	-46.3%	10.9%

Rate Code B/G62
Individual Customer Impacts

	Number of accounts	% of Customers	Average Annual Change	Average Monthly Change	Min % change	Max % change
	3	33.3%	($339,377.90)	($28,281.49)	-7.4%	-5.5%
	1	11.1%	($50,369.03)	($4,197.42)	-1.3%	-1.3%
	1	11.1%	$43,579.70	$3,631.64	0.8%	0.8%
	1	11.1%	$103,112.11	$8,592.68	1.5%	1.5%
	2	22.2%	$248,508.72	$20,709.06	2.2%	2.8%
TOTAL	8	88.9%	$37,578.85	$3,131.57	-7.4%	2.8%

Schedule NG - 15

Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

AVAILABILITY

Electric delivery service under this rate is available for all domestic purposes in an individual private dwelling, an individual private apartment or an individual private condominium. Service is also available for farm customers where all electricity is delivered by the Company.

The Company may under unusual circumstances permit more than one set of living quarters to be served through one metering installation under this rate, but if so, the Customer Charge shall be multiplied by the number of separate living quarters so served.

Service under this rate is also available to residential condominium associations for service provided to common areas and facilities. The condominium association must provide documentation of the establishment of a residential condominium and a written statement identifying all buildings or units which are part of the condominium. Except at the Company's option, service to each individual unit shall be separately metered and billed apart from the common areas and facilities. If the Company permits more than one individual unit to be served through one metering installation, the Customer Charge shall be multiplied by the number of individual units served. Where a condominium includes space used exclusively for commercial purposes, all electric delivery service provided through the meter serving the commercial space will be charged at the appropriate commercial rate. Where a single metering installation records electric delivery service to both common areas/facilities and commercial space, all electric delivery service provided through the single meter will be billed under this rate. Electric delivery service provided to Company owned streetlights will be billed on the appropriate street and area lighting tariff.

A church and adjacent buildings owned and operated by the church may be served under this rate, but any such buildings separated by public ways must be billed separately.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Customer Charge, as defined below, and other applicable Retail Delivery Service Charges set forth in R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates.

CUSTOMER CHARGE

The Customer Charge will be based on a customer's monthly billed kWh according to the following schedule:

Tier	Total Monthly kWh	Monthly Charge
1	Less than 251 kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
2	251 – 750 kWh	
3	751 – 1,200 kWh	
4	1,201 kWh and greater	

The Customer Charge will be based upon the greater of 1) total monthly kWh in the current month or 2) the maximum monthly billed kWh during the preceding eleven months.

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under “Monthly Charge” may be adjusted from time to time in the manner described in the Company’s Transmission Service Cost Adjustment Provision.

Transition Charge Adjustment

The prices under this rate as set forth under “Monthly Charge” may be adjusted from time to time in the manner described in the Company’s Non-Bypassable Transition Charge Adjustment Provision.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company’s Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service.

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Energy Efficiency Program Provision as from time to time effective in accordance with law.

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff.

MINIMUM CHARGE

The minimum charge per month is the Customer Charge.

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: April 1. 2016

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

AVAILABILITY

This service shall apply to Customers in the class identified below:

(i) who receive all or any portion of their electric supply from non-emergency generation unit(s) with a nameplate rating greater than 30 kW ("Generation Units"), where electricity received by the Customer from the Generation Units is not being delivered over Company-owned distribution facilities pursuant to an applicable retail delivery tariff, and

(ii) who expect the Company to provide retail delivery service to supply the Customer's load at the service location when the Generation Units are not supplying all of that load.

Electric delivery service under this rate is applicable to customers with a facility demand of 25 kilowatts or more.

Customers who receive incentive payments for the installation of non-emergency generation units configured for Combined Heat and Power ("CHP") through the Company's approved Energy Efficiency Plan after the effective date of this tariff, and who would otherwise be eligible for this rate, will receive retail delivery service on General C&I Rate G-02 or Large Demand Rate G-32, as applicable.

All Customers served on this rate must elect to take their total electric delivery service under the metering installation as approved by the Company

EXEMPTION FOR CUSTOMER ACCOUNTS ASSOCIATED WITH ELIGIBLE NET METERING SYSTEMS

Customers accounts associated with Eligible Net Metering Systems, as defined in R.I Public Laws of 2011, Chapters 134 and 147, shall be exempt from back-up service rates commensurate with the size of the generating facility and subject to the statutory three (3) percent cap on the aggregate amount of net metering in Rhode Island.

TYPES OF SERVICE

"Back-Up" Retail Delivery Service consists of the Company standing ready to provide retail delivery service to the Customer's load when a non-emergency generator that supplies electricity to the Customer without using Company-owned distribution facilities does not supply all of the Customer's load.

"Supplemental" Retail Delivery Service is the delivery over Company-owned distribution facilities of electricity which is utilized at the Customer's facilities.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Back-Up Service Charges, and the Supplemental Service Charges, as stated below

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

DETERMINATION OF BILLING DEMAND FOR BILLING SUPPLEMENTAL AND BACK-UP per kW (DEMAND) CHARGES

The Billing Demand for each month for purposes of billing Back-Up and Supplemental Service shall be the greatest of the following:

1) The greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kW;

`

2) 90% of the greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kilovolt-amperes;

3) 75% of the greatest Demand as so determined above during the preceding eleven months.

BACK-UP RETAIL DELIVERY SERVICE

a) Rates for Back-Up Retail Delivery Service

Customer Charge per month	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kW	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

The Distribution Charge per kW applicable to Back-up Retail Delivery Service shall be equal to $5.28 (representing the base distribution kW charge applicable to Back-up Service as approved in R.I.P.U.C. Docket No. 4658), plus the approved Operation and Maintenance and CapEx factors applicable to Back-up Service, both per the Company's approved Infrastructure Safety and Reliability Plan, multiplied by a factor of 10%, representing the likelihood that, on average, an outage of an individual customer's generator will occur coincident with the Company's distribution system peak demand approximately 10% of the time.

b) Determination of Back-Up Service Kilowatt Demand

The Back-Up Service Demand shall be the greater of:

1) the fifteen-minute reading from the Customer's generation meter(s) as measured in kilowatts at the time of the Billing Demand;
2) 90% of the fifteen-minute reading from the Customer's generation meter(s) as measured in kilovolt-amperes at the time of the Billing Demand; or
3) One hundred percent (100%) of the greatest Back-up Service Demand as determined above during the preceding eleven (11) months.

c) Installation of Meters on Generation

The Customer shall permit the Company to install meter(s) on the Generation Units providing electricity to the Customer, for purposes of billing under the terms of this rate. The meter shall be in accordance with the Company's reasonable specifications. The Customer will reimburse the Company for the

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

installed cost of the meter and any associated equipment. The Customer shall provide reasonable access to the Company during normal business hours to read such meter in order to bill the Customer for service under this rate.

PEAK AND OFF-PEAK PERIODS

PEAK HOURS:	June - September	-- 8 a.m. - 10 p.m. Weekdays,
	December - February	-- 7 a.m. - 10 p.m. Weekdays
	October – November and March - May	-- 8 a.m. - 9 p.m. Weekdays
OFF-PEAK HOURS:	All other hours	

Weekdays shall mean Monday through Friday, excluding the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Columbus Day (observed), Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

SUPPLEMENTAL RETAIL DELIVERY SERVICE

a) Rates for Supplemental Retail Delivery Service

Transmission Charge per kW	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kW	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Non-Bypassable Transition Charge per kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

b) Assessment of Kilowatt-hour Charges

For purposes of billing kWh charges for Supplemental Distribution and Transmission Service, Customers will be billed on the greater of (i) the actual kWh delivered by the Company or (ii) 90% of the actual kVAh delivered.

For purposes of billing kWh charges for Standard Offer Service, Non-Bypassable Transition Service and Energy Efficiency Programs, Customers will be billed on actual kWh delivered by the Company.

c) Determination of Kilowatt Demand

The Supplemental Distribution Service Demand for each month shall be the Billing Demand in excess of the Back-up Service Demand, but in no case less than 0 kW.

The Supplemental Transmission Service Demand for each month shall be the greater of:

1) The fifteen-minute peak from the meter(s) at the Customer's service entrance(s) as measured in

kW at the time of Billing Demand; or

2) 90% of the fifteen-minute peak demand from the meter(s) at the Customer's service entrance(s) as measured in kilovolt-amperes at the time of Billing Demand

OPTIONAL DETERMINATION OF DEMAND

A Customer who has been served under this rate for one year or more may upon written request have the Demand for each month used for Supplemental Service be based upon the greatest of items (1) and (2) set forth above for Billing Demand, beginning with the next month after such request and running for a period of not less than two consecutive months. In such case, the Distribution Charge per kW, the Distribution Charge per kWh, the Transmission Charge per kW and the Transmission Charge per kWh for Supplemental Service will be increased by 20% during any such period.

In addition, the Company may, at its discretion, agree to a lower demand determination for Back-Up Service below fifteen-minute peak coincident demand of the generation meter(s) if a Customer has installed equipment or configured its facilities in such a manner that automatically limits the requirement for Back-Up Service to the lower agreed-upon demand. Under such a situation, the Customer must demonstrate to the Company's reasonable satisfaction that the Customer's facilities are configured so as to limit the demand that can be placed on the distribution system, or must install and maintain, at no cost to the Company, an automated demand limiter or other similar device as agreed to by the Company which limits deliveries to the Customer over the Company's distribution system based on the lower agreed-upon demand. This equipment can not adversely affect the operation of the Company's distribution system or service to other customers. Such interruptible Back-Up Service shall be negotiated by the Customer and the Company under a separate contract which shall be specific to an individual customer's circumstances.

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Transition Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company's Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

CREDIT FOR HIGH VOLTAGE DELIVERY

If the Customer takes delivery at the Company's supply line voltage, not less than 2400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit per kilowatt of supplemental distribution billing demand for such month shall be allowed against the amount determined under the preceding provisions. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

An additional credit per kilowatt of the supplemental distribution billing demand for such month shall also be allowed if the Customer accepts delivery at not less than 115,000 volts, and the Company is saved the cost of installing any transformer and associated equipment. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

The total amount of the credit allowed under this provision shall not exceed the sum of the Customer Charge, the Distribution Charge per kW and the Distribution Charge per kWh.

HIGH-VOLTAGE METERING ADJUSTMENT

The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1% will be allowed from the amount determined under the preceding provisions.

SECOND FEEDER SERVICE

Except as provided below, Customers receiving second feeder service shall pay a charge per 90% of KVA of reserved second feeder capability. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates The charge for second feeder capability shall apply only to Customers with second feeder capability installed on or after May 1, 1998. The charge for second feeder capability shall not apply to Customers taking service within the Capital Center of Providence or within the downtown Providence underground network system. The Company's Construction Advance Policy 3 shall apply to determine any advance contribution by the customer, using an estimate of revenues to be derived from this second feeder rate. The Company reserves the right to decline second feeder service for engineering reasons.

An additional charge per 90% of KVA of reserved second feeder capability equal to the credit for high voltage delivery for customers taking service at not less than 2400 volts shall be charged if an additional transformer is required at the Customer's facility. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS

Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.

Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

which were disallowed, including any interest required to be paid by the Company to such authority.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: April 1, 2016

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

AVAILABILITY

Electric delivery service under this rate is available for all purposes. If electricity is delivered through more than one meter, except at the Company's option, the Monthly Charge for service through each meter shall be computed separately under this rate. Notwithstanding the foregoing, the Company may require any customer with a 12-month average demand greater than 200 kW to take service on the Large Demand Rate G-32.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Customer Charge, as defined below, and other applicable Retail Delivery Service Charges set forth in R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates .

CUSTOMER CHARGE

The Customer Charge will be based on a customer's monthly billed kWh according to the following schedule:

Tier	Total Monthly kWh	Monthly Charge
1	Up to 100 kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
2	101 – 700 kWh	
3	701 – 2,000 kWh	
4	2,001 kWh and greater	

The Customer Charge will be based upon the greater of 1) total monthly kWh in the current month or 2) the maximum monthly billed kWh during the preceding eleven months.

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision.

Transition Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company's Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service.

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law.

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff.

MINIMUM CHARGE

Metered Service:	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Unmetered Service:	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

However, if the kVA transformer capacity needed to serve a customer exceeds 25 kVA, the minimum charge will be increased for each kVA in excess of 25 kVA. See Additional Minimum Charge, R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates.

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

UNMETERED ELECTRIC SERVICE

Unmetered services are usually not permitted or desirable. However, the Company recognizes that there are certain instances where metering is not practical. Examples of such locations are telephone booths and fire box lights. The monthly bill will be computed by applying the rate schedule to a use determined by multiplying the total load in kilowatts by 730 hours. However, the energy use may be adjusted after tests of the unmetered equipment indicate lesser usage. When unmetered service is provided the aforestated customer charge will be waived and the Unmetered Service Charge per month per location will be implemented.

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS

Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.

Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer which were disallowed, including any interest required to be paid by the Company to such authority.

TERMS AND CONDITIONS

The Company’s Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: April 1, 2016

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.

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.

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%

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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;

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 projects in the upcoming program year; and

vi) Incremental costs incurred to implement and communicate to customers the rates resulting from the rate design review approved by the Commission pursuant to § 39-26.6-24. Incremental costs include changes to the Company's billing system and the cost of communicating and otherwise notifying customers of any changes resulting from the rate design review beyond the customer communications the Company typically undertakes during the year.

4. RATE

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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:

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

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;
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;

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) all incremental costs necessary to meet program objectives or make billing system improvements to

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

implement RE Growth Program pursuant to Section 3.vi) above; and

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

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:

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

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:

(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;

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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

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

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

5) all incremental costs necessary to implement and communicate rate changes as a result of the rate design review pursuant to Section 3.vi);

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

7) 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 = 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

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

THE NARRAGANSETT ELECTRIC COMPANY
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: April 1, 2016

THE NARRAGANSETT ELECTRIC COMPANY
NET METERING PROVISION

I. Definitions

"Commission" shall mean the Rhode Island Public Utilities Commission.

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

"Eligible Net Metering Resource" shall mean eligible renewable energy resource as defined in RIGL Section 39-26-5 including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels.

"Eligible Net Metering System" shall mean a facility generating electricity using an Eligible Net Metering Resource that is reasonably designed and sized to annually produce electricity in an amount that is equal to or less than the Renewable Self-generator's usage at the Eligible Net Metering System Site measured by the three (3) year average annual consumption of energy over the previous three (3) years at the electric distribution account(s) located at the Eligible Net Metering System Site. A projected annual consumption of energy may be used until the actual three (3) year average annual consumption of energy over the previous three (3) years at the electric delivery service account(s) located at the Eligible Net Metering System Site becomes available for use in determining eligibility of the generating system. Schedule B of this tariff is required to be filled out completely to determine eligibility of the above accounts. The Eligible Net Metering System must be owned by the same entity that is the customer of record on the Net Metered Accounts. Notwithstanding any other provisions of this tariff, any Eligible Net Metering Resource: (i) owned by a Public Entity or Multi-municipal Collaborative or (ii) owned and operated by a renewable generation developer on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement shall be treated as an Eligible Net Metering System and all delivery service accounts designated by the Public Entity or Multi-municipal Collaborative for net metering shall be treated as accounts eligible for net metering within an Eligible Net Metering System Site.

"Eligible Net Metering System Site" shall mean the site where the Eligible Net Metering System is located or is part of the same campus or complex of sites contiguous to one another and the site where the Eligible Net Metering System is located or a farm in which the Eligible Net Metering System is located. Except for an Eligible Net Metering System owned by or operated on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, the purpose of this definition is to reasonably assure that energy generated by the Eligible Net Metering System is consumed by net metered electric delivery service account(s) that are actually located in the same geographical location as the Eligible Net Metering System. Except for an Eligible Net Metering System owned by or operated on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, all of the Net Metered Accounts at the Eligible Net Metering System Site must be the accounts of the same customer of record and customers are not permitted to enter into agreements or arrangements to change the name on accounts for the purpose of artificially expanding the Eligible Net Metering System Site to contiguous sites in an attempt to avoid this restriction. However, a property owner may change the nature of the metered service at the delivery service accounts at the site to be master metered (as allowed by applicable state law) in the owner's name, or become the customer of record for each of the delivery service accounts, provided that the owner becoming the customer of record actually owns the property at which the delivery service account is located. As long as the Net Metered Accounts meet the requirements set forth in this definition, there is no limit on the number of delivery service accounts that may be net metered within the Eligible Net Metering System Site. Schedule B of this tariff is required to be filled out completely to determine eligibility of the above accounts.

"Excess Renewable Net Metering Credit" shall mean a credit that applies to an Eligible Net Metering System for that portion of the Renewable Self-generator's production of electricity beyond one hundred percent (100%) and no greater than one hundred twenty-five percent (125%) of the Renewable Self-generator's own consumption at the Eligible Net Metering System Site during the applicable billing period. Such Excess Renewable Net Metering Credit shall be equal to the Company's avoided cost rate, defined for this purpose as the Standard Offer Service kilowatt-hour (kWh) charge for the rate class and time-of-use billing period, if applicable, applicable to the delivery service account(s) at the Eligible Net Metering System Site. Where there are delivery service accounts at the Eligible Net Metering System Site in different rate classes, the Company may calculate the Excess Renewable Net Metering Credit based on the average of the Standard Offer Service rates applicable to those on-site delivery service accounts. The Company has the option to use the energy received from such excess generation to serve the Standard Offer Service load. The Commission shall have the authority to make determinations as to the applicability of this credit to specific generation facilities to the extent there is an uncertainty or disagreement.

"Farm" shall be defined in accordance with RIGL Section 44-27-2, except that all buildings associated with the Farm shall be eligible for Renewable Net Metering Credits and Excess Renewable Net Metering Credits as long as: (i) the buildings are owned by the same entity operating the Farm or persons associated with operating the Farm; and (ii) the buildings are on the same farmland as the project on either a tract of land contiguous with or reasonably proximate to such farmland or across a public way from such farmland.

"ISO-NE" shall mean the Independent System Operator New England, Inc. established in accordance with the NEPOOL Agreement and applicable Federal Energy Regulatory Commission approvals, which is responsible for managing the bulk power generation and transmission systems in New England.

"Multi-municipal Collaborative" shall mean a group of towns and/or cities that enter into an agreement for the purpose of co-owning a renewable generation facility or entering into a Public Entity Net Metering Financing Arrangement.

"Municipality" shall mean any Rhode Island town or city, including any agency or instrumentality thereof, with the powers set forth in Title 45 of the general laws.

"NEPOOL" shall mean New England Power Pool.

"Net Metered Accounts" shall mean one or more electric delivery service accounts owned by a single customer of record on the same campus or complex of sites contiguous to one another and the site where the Eligible Net Metering System is located or a Farm in which the Eligible Net Metering System is located, or all municipal delivery service accounts associated with an Eligible Net Metering System that is: (i) owned by a Public Entity or Multi-municipal Collaborative or (ii) owned and operated by a renewable generation developer on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, provided that the Net Metering Customer or the Public Entity or Multi-municipal Collaborative has submitted Schedule B (attached) with the individual billing account information for each Net Metered Account. Should there be a change to any of the information contained therein, it is the responsibility of the Net Metering Customer or the Public Entity or Multi-municipal Collaborative to submit a revised Schedule B in order for the Company to determine eligibility for the accounts 30 days prior to making any such change.

"Net Metering" shall mean using electricity generated by an Eligible Net Metering System for the purpose of self-supplying power at the Eligible Net Metering System Site and thereby offsetting consumption at the Eligible Net Metering System Site through the netting process established in this provision.

"Net Metering Customer" shall mean a customer of the Company receiving and being billed for electric delivery service whose delivery account(s) are being net metered.

"Person" shall mean an individual, firm, corporation, association, partnership, farm, town or city of the State of Rhode Island, Multi-municipal Collaborative, or the State of Rhode Island or any department of the state government, governmental agency or public instrumentality of the state.

"Project" shall mean a distinct installation of an Eligible Net Metering System. An installation will be considered distinct if it is installed in a different location, or at a different time, or involves a different type of renewable energy.

"Public Entity" means the State of Rhode Island, Municipalities, wastewater treatment facilities, public transit agencies or any water distributing plant or system employed for the distribution of water to the consuming public within the State of Rhode Island including the water supply board of the City of Providence.

"Public Entity Net Metering Financing Arrangement" shall mean arrangements entered into by a Public Entity or Multi-municipal Collaborative with a private entity to facilitate the financing and operation of a Net Metering resource, in which the private entity owns and operates an Eligible Net Metering Resource on behalf of a Public Entity or Multi-municipal Collaborative, where: (i) the Eligible Net Metering Resource is located on property owned or controlled by the Public Entity or one of the Municipalities, as applicable, and (ii) the production from the Eligible Net Metering Resource and primary compensation paid by the Public Entity or Multi-municipal Collaborative to the private entity for such production is directly tied to the consumption of electricity occurring at the designated Net Metered Accounts.

"Renewable Net Metering Credit" shall mean a credit that applies to an Eligible Net Metering System up to one hundred percent (100%) of the Renewable Self-generator's usage at the Eligible Net Metering System Site over the applicable billing period. This credit shall be equal to the total kilowatt-hours of electricity generated and consumed on-site during the billing period multiplied by the sum of the:

(i) Standard Offer Service kilowatt-hour charge for the rate class applicable to the net metering customer;
(ii) Distribution kilowatt-hour charge;
(iii) Transmission kilowatt-hour charge; and
(iv) Transition kilowatt-hour charge.

"Renewable Self-generator" shall mean an electric delivery service customer who installs or arranges for an installation of renewable generation that is primarily designed to produce electricity for consumption by that same customer at its delivery service account(s).

II. Terms and Conditions

The following policies regarding Net Metering of electricity from Eligible Net Metering Systems and regarding any Person that is a Renewable Self-generator shall apply:

1. The maximum allowable capacity for Eligible Net Metering Systems, based on name plate capacity, shall be five megawatts (5 MW).

2. For ease of administering Net Metered Accounts and stabilizing Net Metered Account bills, the Company may elect (but is not required) to estimate for any twelve (12) month period i) the production from the Eligible Net Metering System and ii) aggregate consumption of the Net Metered Accounts at the Eligible Net Metering System Site and establish a monthly billing plan that reflects the expected Renewable Generation Credits and Excess Renewable Generation Credits that would be applied to the Net Metered Accounts over twelve (12) months. The billing plan would be designed to even out monthly billings over twelve (12) months, regardless of actual production and usage. If such election is made by the Company, the Company would reconcile payments and credits under the billing plan to actual production and consumption at the end of the twelve (12) month period and apply any credits or charges to the Net Metered Accounts for any positive or negative difference, as applicable. Should there be a material change in circumstances at the Eligible Net Metering System Site or associated Net Metered Accounts during the twelve (12) month period, the estimate and credits may be adjusted by the Company during the reconciliation period. The Company also may elect (but is not required) to issue checks to any Net Metering Customer in lieu of billing credits or carry forward credits or charges to the next billing period. For residential Eligible Net Metering Systems twenty-five kilowatts (25 kW) or smaller, the Company, at its option, may administer Renewable Net Metering Credits month to month allowing unused credits to carry forward into following billing period.

3. If the electricity generated by an Eligible Net Metering System during a billing period is equal to or less than the Net Metering Customer's usage during the billing period for Net Metered Accounts at the Eligible Net Metering System Site, the customer shall receive Renewable Net Metering Credits, which shall be applied to offset the Net Metering Customer's usage on Net Metered Accounts at the Eligible Net Metering System Site.

4. If the electricity generated by an Eligible Net Metering System during a billing period is greater than the Net Metering Customer’s usage on Net Metered Accounts at the Eligible Net Metering System Site during the billing period, the customer shall be paid by Excess Renewable Net Metering Credits for the excess electricity generated beyond the Net Metering Customer’s usage at the Eligible Net Metering System Site up to an additional twenty-five percent (25%) of the Renewable Self-generator’s consumption during the billing period; unless the Company and Net Metering Customer have agreed to a billing plan pursuant to Section II.2.

5. As a condition to receiving Renewable Generation Credits or Excess Renewable Generation Credits pursuant to this provision, customers who install Eligible Net Metering Systems must enter into an interconnection agreement and comply with the Company’s Standards for Connecting Distributed Generation, as amended and superseded from time to time.

6. Customers eligible to receive Renewable Net Metering Credits or Excess Renewable Net Metering Credits pursuant to Sections II.3 and II.4, respectively, shall be required to complete Schedule B.

7. As a condition to receiving any payments pursuant to this provision, customers who install Eligible Net Metering Systems with a nameplate capacity in excess of 25 kW must comply with any and all applicable NEPOOL and ISO-NE rules, requirements, or information requests that are necessary for the Eligible Net Metering System’s electric energy output to be sold into the ISO-NE administered markets. If the Company must provide to NEPOOL or ISO-NE any information regarding the operation, output, or any other data in order to sell the output of the Eligible Net Metering System into the ISO-NE administered markets, the customer who installs an Eligible Net Metering System must provide such information to the Company prior to the project being authorized to operate in parallel with the Company’s electric distribution system.

8. NEPOOL and ISO-NE have the authority to impose fines, penalties, and/or sanctions on participants if it is determined that a participant is violating established rules in certain instances. Accordingly, to the extent that a fine, penalty, and/or sanction is levied by NEPOOL or the ISO-NE as a result of the Owner of the Eligible Net Metering System’s failure to comply with a NEPOOL or ISO-NE rule, requirement or information request, the Eligible Net Metering System will be responsible for the costs incurred by the Company, if any, associated with such fine, penalty and/or sanction.

III. Rates for Distribution Service to Eligible Net Metering System and Net Metered Accounts

1. Retail delivery service by the Company to the Eligible Net Metering System and Net Metered Accounts shall be governed by the tariffs, rates, terms, conditions, and policies for retail delivery service which are on file with the Commission.

2. The Standard Offer Service and retail delivery rates applicable to any Net Metered Account shall be the same as those that apply to the rate classification that would be applicable to such delivery service account in the absence of Net Metering, including customer and demand charges, and no other charges may be imposed to offset Net Metering Credits.

3. Net Metered Accounts associated with an Eligible Net Metering System shall be exempt from backup service rates commensurate with the size of the Eligible Net Metering System.

4. The account associated with an Eligible Net Metering System where the Eligible Net Metering System is geographically segregated from the Eligible Net Metering Site and Net Metering Accounts shall be subject to an Access Fee for the use of the Company's distribution system by the Eligible Net Metering System for the purpose of exporting electricity generated by the Eligible Net Metering System into the electric distribution system. The Access Fee shall be a fixed per-kilowatt charge assessed monthly and shall be applied to a fixed capacity value determined as the nameplate capacity of the Eligible Net Metering System adjusted by a capacity factor applicable to the Eligible Net Metering System's technology. The customer of record of the account associated with the Eligible Net Metering System must execute an Access Service Agreement and be subject to its terms and conditions. The Access Fee does not alter the obligations for the interconnection of the Eligible Net Metering System to the Company's electric distribution system as provided in II.5 above.

   The Access Fee per-kilowatt shall be $8.50 for Eligible Net Metering Systems interconnected to the Company's secondary voltage distribution system and $6.00 for Eligible Net Metering Systems interconnected to the Company's primary voltage distribution system.

IV. <u>Cost Recovery</u>

1. Any prudent and reasonable costs incurred by the Company pursuant to achieving compliance with RIGL Section 39-26.2-3(a) and the annual amount of any Renewable Net Metering Credits or Excess Renewable Net Metering Credits provided to Eligible Net Metering Systems, shall be aggregated by the Company and billed to all distribution customers on an annual basis through a uniform per kilowatt hour (kWh) Net Metering Charge embedded in the distribution component of the rates reflected on customer bills.

2. The Company will include the energy market payments received from ISO-NE for the electricity generated by Eligible Net Metering Systems in the Company's annual reconciliation of the Net Metering Charge. Eligible Net Metering Systems with a nameplate capacity in excess of 25 kW shall provide all necessary information to, and cooperate with, the Company to enable the Company to obtain the appropriate asset identification for reporting generation to ISO-NE. The Company will report all exported power to the ISO-NE as a settlement only generator and net this reported usage and associated payment received against the annual amount of Standard Offer Service component of any Renewable Net Metering Credits or Excess Renewable Net Metering Credits provided to accounts associated with Eligible Net Metering Systems.

Schedule B – Additional Information Required for Net Metering Service

THE NARRAGANSETT ELECTRIC COMPANY
NET-METERING APPLICATION OF CREDITS

Customer Name: ____

Account Number: ____

Facility Address:

City: State: RI Zip Code:

The Agreement is between ___________________________, a Net-Metered Customer ("NMC") and The Narragansett Electric Company (the "Company") for application of credits earned through net-metering from the NMC located at ___________________________, Rhode Island.

The NMC agrees to comply with the provisions of the Net-Metering Provision, the applicable retail delivery tariffs and the Terms and Conditions for Distribution Service that are on file with the Rhode Island Public Utilities Commission as currently in effect or as modified, amended, or revised by the Company, and to pay any metering and interconnection costs required under such tariff and policies.

A.) NMC Address: ______________________

____

____

Nameplate rating (AC) of the Eligible Net Metering System ______________kWs
Estimated annual generation in kWhs of Eligible Net-Metering System ______kWhs

Net Metered Account(s)

The following information must be provided for each individual Net Metered Account in a proposed Eligible Net Metering site:

Name: ___________________________________ (Except in the case of a Public Entity or Multi-municipal Collaborative, the customer of record must be the same as the NMC)

Service Address: _________________________________

National Grid Account number: ______________________

Three (3) years average kWh usage for this account _________________

Total three (3) years average kWh usage for all accounts listed as an Eligible Net Metering Site __________

Once this information is received, the Company will determine if the accounts listed are eligible for net metering.

B.) For any Billing Period in which the NMC earns Net Metering Credits, please indicate how the Distribution Company will apply them:

- ☐ Apply all of the Net Metering Credits to the account of the NMC (skip Items C and D below)
- ☐ Allocate all the Net Metering Credits to the accounts of eligible Customers (please fill out C and D below)
- ☐ Both apply a portion of the Net Metering Credits to the NMC's account and allocate a portion to the accounts of eligible Customers (please fill out C and D below)

The Company will notify the NMC within 30 days of the Company's receipt of Schedule B whether it will allocate or purchase Net Metering Credits. If the Company elects to purchase Net Metering Credits, the Company will render payment by issuing a check to the NMC each Billing Period, unless otherwise agreed in writing by the NMC and Company. If the Company elects to allocate Net Metering Credits, the NMC must complete Item C and submit the revised Schedule B to the Company.

C.) Please state the total percentage of Net Metering Credits to be allocated.

% Amount of the Net Metering Credit being allocated.

The total amount of Net Metering Credits being allocated shall not exceed 100%. Any remaining percentage will be applied to the NMC's account.

Please identify each eligible Customer account to which the NMC is allocating Net Metering Credits by providing the following information (attach additional pages as needed):

NOTE: If a designated Customer account closes, the allocated percentage will revert to the NMC's account, unless otherwise mutually agreed in writing by the NMC and the Company.

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

D.) The terms of this Schedule B shall remain in effect unless and until the NMC executes a revised Schedule B and submits it to the Company. Unless otherwise required herein or mutually agreed to in writing by the NMC and the Company, a revised Schedule B shall not be submitted more than once in any given calendar year.

E.) A signature on the application shall constitute certification that (1) the NMC has read the application and knows its contents; (2) the contents are true as stated, to the best knowledge and belief of the NMC; and (3) the NMC possesses full power and authority to sign the application.

Notice

Execution of this agreement will cancel any previous agreement for the net-metered account under the Net-Metering Provision.

The Company or NMC may terminate this agreement on thirty (30) days written notice, which includes a statement of reasons for such termination. In addition, the NMC must re-file this agreement annually.

Agreed and Accepted – Please sign

[**NAME OF NMC**] Date: ____________________

By:____

Name:
Title:

The Narragansett Electric Company Date: ___________________
d/b/a National Grid

By:____

Name:
Title:

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

1. Introduction

This tariff ("Tariff") describes the terms and conditions under which an Applicant for an eligible distributed generation project ("DG Project") will receive funding pursuant to Chapter 26.6 of Title 39 of the Rhode Island General Laws ("Chapter 26.6"), which refers to the Renewable Energy Growth Program ("RE Growth Program").

This Tariff will apply to an Applicant who has installed a DG Project at a Non-Residential Customer's service location or another location that allows for interconnection to the Company's electric distribution system. For this purpose, a Non-Residential Customer ("Customer") is defined as a customer receiving retail delivery service on any rate schedule other than the Company's residential rate schedules (Basic Residential Rate A-16 and Low Income Rate A-60). This Tariff will also apply to a DG Project that does not provide On-Site Use to a Customer receiving retail delivery service from the Company. The Applicant and the Customer may be the same person, or different persons, subject to the eligibility standards in the Solicitation and Enrollment Process Rules ("Rules") and this Tariff.

This Tariff applies to the Applicant for a DG Project that is awarded a Certificate of Eligibility by the Commission or the Company pursuant to the Rules, and any successor Applicant for the Project. Upon being awarded a Certificate of Eligibility, a DG Project has a defined period to meet all requirements to receive compensation pursuant to this Tariff, which is: (1) 48 months for a Small DG Project using hydropower; (2) 36 months for a Project using anaerobic digestion; or (3) 24 months for a Project using another eligible technology.

The Applicant is required to update the Application information for the DG Project, including but not limited to information concerning: the DG Project owner, the Customer, the electric service account, and the recipient of Performance-Based Incentive Payments. Also, an Applicant may designate a successor Applicant for a DG Project under this Tariff with notice to the Company and without the consent of the Company. The Applicant may, but need not be, the same person or entity to pursue the interconnection of the DG Project with the Company's electric distribution system. The Applicant maintains the obligation to ensure that all aspects of a DG Project comply with the terms of the Company's Solicitation and Enrollment Process Rules and this Tariff. Upon notice to the Company, the Applicant may transfer the compensation under this Tariff to another person or entity without the consent of the Company.

2. Definitions

The following words and terms shall have the following meanings when used in this Tariff:

a. Applicant: the person or entity with legal authority to enroll the DG Project in the RE Growth program, and with the obligation to ensure that all aspects of the DG Project comply with the Rules.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

b. Application: the RE Growth Program Enrollment short form application submitted by the Applicant.

c. Board: the Distributed Generation Board established pursuant to R.I. Gen. Laws § 39-26.2-10 and having expanded responsibilities under Chapter 26.6.

d. Ceiling Price: the bidding price cap applicable to an enrollment in a given Renewable Energy Class and Program Year. Ceiling prices will be recommended by the Board and approved by the Commission.

e. Certificate of Eligibility: written notice by the Company or Commission that a DG Project has been enrolled in the RE Growth Program. Upon an award of a Certificate of Eligibility, a DG Project will be entitled to receive Performance-Based Incentive Payments for a specified term, pursuant to the terms and conditions of the applicable Tariff supplement.

f. Commercial-Scale Solar Project: a solar DG Project with a nameplate capacity greater than 250 kilowatts (250 kW) but less than 1 megawatt (1 MW).

g. Commission: the Rhode Island Public Utilities Commission.

h. Company: The Narragansett Electric Company d/b/a National Grid.

i. Customer: a customer receiving retail delivery service pursuant to one of the Company's non-residential retail delivery service rate schedules and listed as the customer-of-record on the billing account associated with the service location.

j. DG Project: a distinct installation of an electrical generation facility that is located in the Company's service territory, is connected to the Company's electric distribution system, and has a nameplate capacity no greater than five megawatts (5 MW) using eligible renewable energy resources as defined in 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.

k. ISO-New England, Inc. ("ISO-NE"): the Independent System Operators of New England, Inc., established in accordance with the NEPOOL Agreement and applicable Federal Energy Regulatory Commission approvals, which is responsible for managing the bulk power generation and transmission systems in New England.

l. Large DG Project: a DG Project with a nameplate capacity that exceeds the size of a Small DG Project in a given year, but is no greater than five megawatts (5 MW) nameplate capacity.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

m. Large-Scale Solar Project: a solar DG Project with a nameplate capacity of one megawatt (1 MW) or greater and up to and including five megawatts (5 MW).

n. Medium-Scale Solar Project: a solar DG Project with a nameplate capacity greater than 25 kilowatts (25 kW) and up to and including 250 kilowatts (250 kW).

o. Nameplate Capacity: the maximum rated output or gross output of a DG Project. For a solar DG Project, it is the total rated power output of all the DG Project's panels, measured in direct current.

p. Office: the Rhode Island Office of Energy Resources.

q. On-Site Use: the amount of energy used at a Customer's service location during a billing period that may be delivered by the Company, or supplied by the DG Project, or both.

r. Output Certification: certification provided by an independent engineer (licensed Professional Engineer) stating that construction of both the DG Project and the interconnection facilities is complete in all material respects, that the metering has been installed and tested, that the Nameplate Capacity is as on the Certificate of Eligibility, and that the DG Project is capable of producing at least 90% of the maximum hourly output specified on the Certificate of Eligibility.

s. Performance-Based Incentive: either a standard or competitively bid price per kilowatt-hour ("kWh") that is applicable to the output of a DG Project when the Applicant has been awarded a Certificate of Eligibility, pursuant to the Rules.

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

u. Renewable Energy Classes: categories for different renewable energy technologies using eligible renewable energy resources as defined in 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 specified in § 39-26-2(6).

v. Renewable Energy Certificate ("REC"): an electronic record produced by the New England Generation Information System ("NE-GIS") that identifies the relevant generation attributes of each megawatt-hour accounted for in the NE-GIS.

w. Small-Scale Solar Project: a solar DG Project with a nameplate capacity of up to and including 25 kilowatts (25 kW).

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

x. Small DG Project: either: (1) a Small-Scale Solar Project; (2) a Medium-Scale Solar Project; (3) a wind DG Project with a nameplate capacity of at least fifty kilowatts (50 kW) up to one and one-half megawatts (1.5 MW); or (4) a DG Project using renewable energy resources other than solar and wind, with a nameplate capacity to be determined by the Board, but no greater than one megawatt (1 MW).

y. Solicitation and Enrollment Process Rules: the rules governing the solicitation, enrollment, and award processes for the RE Growth Program for Non-Residential Customers, established pursuant to Chapter 26.6, and approved by the Commission.

z. Station Service: energy used to operate auxiliary equipment and other load that is directly related to the production of energy by a DG Project.

3. **Performance Guarantee Deposit**

a. No later than five (5) business days after a project is offered a Certificate of Eligibility, the Applicant shall submit by wire transfer a Performance Guarantee Deposit (“Deposit”) as identified on the Certificate of Eligibility. Upon confirmation of the receipt of the Deposit, the Company shall award the Certificate of Eligibility. Each Deposit shall be no less than $500.00 and no greater than $75,000.00. The Deposit shall be calculated as $15.00 for Small DG Projects or $25.00 for Large DG Projects, multiplied by the estimated RECs to be generated during the DG Project’s first year of operation.

b. If the Company does not receive a Deposit by the date required, the Company may withdraw the Certificate of Eligibility offer and not proceed further with the Applicant in that enrollment.

c. The Deposit shall be refunded to the Applicant during the first year of the DG Project’s operation, paid quarterly. In the event that the Applicant terminates the DG Project prior to operation, the Deposit will be forfeited.

d. After receiving the Certificate of Eligibility, the Applicant must provide the Output Certification within: (1) 48 months for Small DG Projects using hydropower; (2) 36 months for anaerobic digestion; or (3) 24 months for all other DG Projects. If the Output Certification is not received within the specified timeframe, the Certificate of Eligibility will be voided and the Deposit will be forfeited.

e. Once a DG Project has provided the Output Certification to National Grid, the project then has 90 days to meet all other requirements specified in Section 8(a) to receive payment pursuant to the Tariff.

f. An Applicant may elect, for any reason, to extend the DG Project deadline for providing the Output Certification by an additional six (6) months with no additional Deposit. After such initial six-month extension, the Applicant may elect, for any reason, to extend Output Certification deadline for an additional six-month period by posting an additional Deposit amount equal to one-half of the original Deposit amount. An Applicant shall not extend the deadline to provide the Output Certification by more than one (1) year in total. Prior to the expiration of the timeframe applicable to the Applicant's DG Project, as specified herein Section 3(d) or as extended as provided for by Section 3(f), the Applicant must notify the Company of its election to extend the DG Project deadline.

g. If the Applicant is unable to provide the Output Certification within the timeframe specified in Section 3(d), or as extended pursuant to Section 3(f), because of non-completion of the necessary system modifications on the Company's side of the meter or any other interconnection delays that are beyond the reasonable control of the Applicant, the deadline for providing the Output Certification will be extended until such time as the DG Project has received approval from the Company to interconnect to the Company's distribution system and begin production, with no additional deposit required.

h. If an act of God occurs within the timeframe allowed for providing the Output Certification, and as a direct result of the act of God, the DG Project is incapable of providing the Output Certification within the timeframe prescribed in this Tariff, the DG Project shall be terminated and the Deposit shall be refunded immediately.

i. Small-Scale Solar Projects and Medium-Scale Solar Projects are not required to submit a Performance Guarantee Deposit or provide an Output Certification. In order to receive Performance-Based Incentive payments under this Tariff, such projects will have 24 months after being awarded a Certificate of Eligibility to achieve operation at expected availability and capacity and meet all other requirements under this Tariff.

4. **Interconnection**

a. The interconnection of the DG Project with the Company's distribution system and any system modifications required by the Company shall be in accordance with the Standards for Connecting Distributed Generation and coordinated or delegated by the Applicant.

b. Except for Small-Scale Solar Projects and Medium-Scale Solar Projects, all Applicants for DG Projects awarded a Certificate of Eligibility are required to submit quarterly reports to the Company and the Office reporting on the progress of construction. Failure to submit these reports may result in the loss of the Applicant's Certificate of Eligibility.

5. **Project Segmentation**

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

There is a prohibition on project segmentation within the RE Growth Program. If the Company determines that an Applicant has segmented a DG Project into two or more smaller-sized Projects for the purpose of qualifying them for smaller renewable energy class, the Company will award the Applicant a Certificate of Eligibility for only one of the DG Projects. In making its determination, the Company will look for one of the following exceptions:

i. The DG Projects use different renewable energy resources; or

ii. The DG Projects use the same renewable energy resource, but they are: (1) electrically segregated; (2) separately metered; and (3) can demonstrate that 24 months have elapsed between the commencement of operation for one DG Project and the commencement of construction of any additional DG Project.

iii. DG Projects installed on contiguous parcels will not be considered segmented if they serve different Non-Residential Customers and both Customers receive bill credits under Option 2 as defined in Section 8.c.

If the Company determines that a DG Project is ineligible to enroll in the RE Growth Program due to project segmentation, the DG Project may be eligible for compensation pursuant to the Net Metering Provision or through other energy market participation. If an Applicant is awarded a Certificate of Eligibility for a DG Project and is receiving Performance-Based Incentive Payments pursuant to this Tariff it will not receive compensation pursuant to the Net Metering Provision for the same DG Project during the term specified in the applicable Tariff supplement.

6. **Metering**

a. A Company-owned interval meter must be installed on all DG Projects that are enrolled in the RE Growth Program for the purpose of measuring and reporting the output of the DG Project. In the event that there is an existing service location with an existing meter, the meter for the DG Project shall be wired in parallel with, and be adjacent to, the existing service meter. In the event an existing service meter is present, the existing service meter will be exchanged for an interval meter by the Company at the Applicant’s expense.

b. For Medium-Scale Solar Projects, Commercial-Scale Solar Projects, Large-Scale Solar Projects, and DG Projects of other eligible technologies, the Applicant is responsible for the cost of a revenue-quality interval meter and associated metering equipment, including required remote communication for measuring and reporting the output of the DG Project as well as any existing service meter. An Applicant may elect to supply the meter and associated equipment provided that it conforms to the Company’s metering standards and the Rhode Island Division of Public Utilities and Carrier’s Rules for Prescribing Standards for Electric Utilities, as may be amended from time to time. At the request of the Applicant, the Company will provide the required interval meter and associated equipment, subject to the

Company having such equipment available and the Applicant reimbursing the Company for its cost.

c. The Company must be provided with adequate access to read the meter(s), and to install, repair, maintain and replace the meter(s), if applicable.

7. **Energy, Capacity, Renewable Energy Certificates and Other Environmental Attributes**

a. Prior to receiving compensation pursuant to Section 8 of this Tariff, an Applicant, at its own cost, must obtain Commission certification of a DG Project as an Eligible Renewable Energy Resource pursuant to the Commission's Rules and Regulations Governing the Implementation of a Renewable Energy Standard. The Company shall assume the obligation to qualify the DG Project under the renewable portfolio standard or similar law and/or regulation of New York, Massachusetts, and/or one or more New England states and/or any federal renewable energy standard.

b. The Applicant for a DG Project shall provide all necessary information to, and cooperate with, the Company to enable the Company to obtain the appropriate asset identification for reporting generation to ISO-NE and the NEPOOL Generation Information System for the creation of RECs, designate the Company, or another party as directed by the Company, as the Applicant's Responsible Party under the NEPOOL-GIS rules, and direct all RECs from the DG Project to the Company's appropriate NEPOOL-GIS account. If requested by the Company, Applicant will provide approvals or assignments, as necessary, to facilitate Applicants participation in asset aggregation or other model of asset registration and reporting.

For the term specified in the applicable Tariff supplement, the Company shall have the irrevocable rights and title to the following products produced by the DG Project: (1) RECs; (2) energy; and (3) any other environmental attributes or market products associated with the sale of energy or energy services produced by the DG Project, provided, however, that it shall be the Company's choice to acquire the capacity of the DG Project at any time after it is awarded a Certificate of Eligibility by the Commission or the Company pursuant to the Rules. Environmental attributes shall include any and all generation attributes or energy services established by regional, state, federal, or international law, rule, regulation or competitive market or business method that are attributable, now or in the future, to the output produced by the DG Project during the term of service specified on the applicable Tariff supplement.

8. **Performance-Based Incentive Payment**

a. Eligibility

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

Upon receipt of a Certificate of Eligibility, the Applicant is entitled to the Performance-Based Incentive Payment for the term specified in the applicable Tariff supplement, provided that the Applicant has complied with all other requirements of this Tariff and the Solicitation and Enrollment Process Rules.

As a condition for receiving monthly payments pursuant to Section 9c, the Applicant must provide confirmation of the following: 1) the Company's written authority to interconnect to its electric distribution system and Applicant's payment of all amounts due; 2) Commission certification of the DG Project as an Eligible Renewable Energy Resource; 3) registration of the DG Project with the ISO-NE and NEPOOL GIS; and 4) except for small-scale and medium-scale solar, the Output Certification. If an Applicant or Customer is no longer in good standing with regard to payment plans or agreements, if applicable, and other obligations to the Company (including but not limited to meeting all obligations under an interconnection service agreement), the Company may withhold payments under this Tariff. In addition, the Customer must remain in good standing with regard to the electric service account receiving Bill Credits pursuant to this tariff.

b. Performance-Based Incentive

The Performance-Based Incentive will be a fixed per-kWh price for the term specified in the applicable Tariff supplement.

The Performance-Based Incentive for Small-Scale Solar and Medium-Scale Solar shall be a standard Performance-Based Incentive that is recommended by the Board and approved by the Commission. The Performance-Based Incentive for other DG Projects shall be determined through competitive bidding.

Zonal Incentive: In addition to the Performance-Based Incentive, the Company may propose, and the Commission may approve, a zonal incentive, which is in addition to the Performance-Based Incentive for DG Projects that are: 1) located in designated geographic areas; or 2) comply with other specified conditions. Any Zonal Incentive shall be reflected in the applicable Tariff supplement.

c. Performance Based Incentive Payment

The Performance-Based Incentive Payment will be the fixed per-kWh Performance-Based Incentive, plus any Zonal Incentive where applicable, applied to the measured kilowatt-hours (kWh) produced by the DG Project, net of any Station Service.

Before a DG Project begins to operate, an Applicant must notify the Company of the manner by which it will be compensated for its output under one of the two options below. The Applicant may select Option 2 only if the DG Project can be configured to serve on-site load and the DG Project is reasonably designed and sized to produce electricity at an annual level equal to or less than 1) the Customer's On-Site Use as measured over the previous three (3) years at the electric service account located at the Customer's service location; 2) the annualized On-Site Use over the period of service to the Customer's service location if such service has been provided for less than three years; or 3) a reasonable estimate of annual On-Site Use if the Project is located at a new service location. The Applicant may change the selection only one time after the DG Project begins to operate provided that the Applicant gives the Company no less than 60 days' notice to implement the change. Additional changes to the method of compensation may be allowed at the discretion of the Company. The options are:

1. Option 1: Direct payment of the entire Performance-Based Incentive Payment in the form of a check or such other payment method that is mutually agreed upon by the Company and the Applicant; or

2. Option 2: A combination of direct payment and a Customer bill credit, in which the value of the bill credit will be based upon the On-Site Use, up to, but not exceeding, the metered generation of the DG Project.

If a DG Project selects Option 2, the Performance-Based Incentive Payment shall be provided as follows:

The Customer's bill will be based upon the On-Site Use, the retail delivery service charges and the Standard Offer Service or Non-Regulated Power Producer charges in effect during the billing period and which apply to the Customer's retail delivery service rate class. The Company shall apply a Bill Credit, as calculated below, to offset the Customer's bill. The Bill Credit will appear as a separate line item on the Customer's bill.

BC = OSU (kWh) x (DCHG + SOS)

Where:

BC = Bill Credit

OSU (kWh) = On-Site Use kWh at the lesser of 1) the On-Site Use measured in kWh per month, or 2) the DG Project output measured in kWh per month.

DCHG = the sum of all retail delivery service per kWh charges applicable to the Customer's retail delivery service rate class per RIPUC No. 2095, Summary of Retail Delivery Rates, as may be amended from time to time.

SOS = the Standard Offer Service charge applicable to the Customer's retail delivery service rate class per RIPUC No. 2096, Summary of Standard Offer Service Rates, as may be amended from time to time.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

The remaining amount of the Performance-Based Incentive Payment will be paid in the form a check (or another agreed-upon means) to the recipient as identified on the Application. The Customer will be responsible for paying any balance due on the electric bill in accordance with the Terms and Conditions for Distribution Service.

If the Bill Credit in a given month exceeds the Performance-Based Incentive Payment, the Customer shall receive the full amount of the Bill Credit, which will not exceed the total of the per kWh delivery service charges and applicable Standard Offer Service charges, excluding the customer charge and any applicable taxes. There will be no additional amounts related to the calculation of the Performance-Based Incentive Payment charged or credited to the Customer or the recipient identified on the Application.

Only one billing account will be eligible to receive Bill Credits from each DG Project pursuant to this provision.

9. **Access Fee**

An Applicant choosing Option 1 as described in Section 8.c.1 shall be subject to an Access Fee for the use of the Company’s distribution system by the DG Project for the purpose of exporting electricity generated by the DG Project into the electric distribution system. The Access Fee shall be a fixed per-kilowatt charge assessed monthly and shall be applied to a fixed capacity value determined as the Nameplate Capacity of the DG Project adjusted by a capacity factor applicable to the DG Project’s technology. The customer of record of the account associated with the DG Project must execute an Access Service Agreement and be subject to its terms and conditions. The Access Fee does not alter the Applicant’s obligations for the interconnection of the DG Project to the Company’s electric distribution system as provided in Section 4.a above.

The Access Fee per-kilowatt shall be $8.50 for DG Projects interconnected to the Company’s secondary voltage distribution system and $6.00 for DG Projects interconnected to the Company’s primary voltage distribution system. The Access Fee is assessed to the retail delivery service account associated with the DG Project regardless of the method by which the Applicant receives compensation pursuant to Section 8.c.

10. **Other Company Tariff Requirements**

a. The Company will provide the Customer with retail delivery service under the applicable retail delivery service tariff and the Company’s Terms and Conditions for Distribution Service.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

b. The Applicant is required to comply with Company's Standards for Connecting Distributed Generation.

c. To be eligible to receive Renewable Net Metering Credits or excess Renewable Net Metering Credits pursuant to the Company's Net Metering Provision following the termination of the Customer's participation in the RE Growth Program, a DG Project and a Customer receiving credits from such a facility must comply with the applicable provisions of the Company's Net Metering Provision.

d. The Company's recovery of costs incurred to implement and administer the RE Growth Program is pursuant to the Renewable Energy Growth Program Cost Recovery Provision.

11. **Dispute Resolution**

If any dispute arises between the Company and either the Applicant or the Customer, the dispute shall be brought before the Commission for resolution. Such disputes may include but are not limited to those concerning the Rules, terms, conditions, rights, responsibilities, the termination of the Tariff or Tariff supplement, or the performance of the Applicant, the Customer, or the Company.

12. **Termination Provisions**

The Applicant and the Customer shall comply with the provision of this Tariff through the end of the term specified in the applicable Tariff supplement. The Applicant and the Customer may not terminate their obligations under this Tariff unless and until the Company consents to such termination. The Company will not unreasonably delay or withhold its consent to an Applicant's request to terminate if the Applicant cannot fulfill the obligations because of an event or circumstance that is beyond the Applicant's reasonable control and for which the Applicant could not prevent or provide against by using commercially reasonable efforts.

Only the DG Project described on the Certificate of Eligibility is eligible to participate under this Tariff. In no event shall an Applicant expand a DG Project's nameplate capacity beyond what is allowed by the Certificate of Eligibility. If a DG Project exceeds the nameplate capacity allowed by the Certificate of Eligibility, or the Company determines that a Customer or Applicant has violated the terms and conditions of this Tariff, the Company may, after notifying the Customer or Applicant in writing of such non-compliance and providing the Customer or Applicant a reasonable period to remedy such non-compliance and the violation persists, request the Commission to review the non-compliance and determine appropriate action, which may include requiring the Customer or Applicant to comply with the applicable provision being violated or revoking the Customer's or Applicant's Certificate of Eligibility.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

13. **Statutory Authority**

This Tariff is filed in compliance with R.I. Gen. Laws. § 39-26.6-10. All revisions to the Tariff will be filed annually by November 15. Tariff supplements will be filed annually and following each scheduled RE Growth Program enrollment, as necessary. This Tariff and its supplements are subject to review, approval, and the exclusive jurisdiction of the Commission.

Effective Date: April 1, 2016

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Program Year: April 1, 2015 through March 31, 2016

Performance-Based Incentives and associated Performance-Based Incentive Payment shall remain in effect during the term of service noted below in accordance with R.I.G.L. § 39-26.6-20.

Term of Service represents the period of time during which the DG Project earns Performance-Based Incentive Payments. The billing month during which Performance-Based Incentive Payments begin will be specific to each individual DG Facility, and the Term of Service for a particular DG Facility will commence upon the first month of operation.

Renewable Energy Class	System Size	Ceiling Price/Standard Performance –Based Incentive (per kWh)	Term of Service
Small-Scale Solar I, Host Owned	1 to 10 kW	41.35¢	15 years
Small-Scale Solar I, Host Owned	1 to 10 kW	37.75¢	20 years
Small-Scale Solar I Third-Party Owned	1 to 10 kW	32.95¢	20 years
Small-Scale Solar II	11 to 25 kW	29.80¢	20 years
Medium-Scale Solar	26 to 250 kW	24.40¢	20 years

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Program Year: April 1, 2015 through March 31, 2016

Renewable Energy Class	Ceiling Price	Enrollment Date	Applicant Name	DG Facility Address	Nameplate Capacity (MW)	Performance Incentive (per kWh)	Term of Service
Commercial-Scale Solar	20.95¢						20 years
Large-Scale Solar	16.70¢						20 years
Wind I (1.5MW to 2.99MW) with Investment Tax Credit	18.40¢						20 years
Wind I (1.5MW to 2.99MW) with Production Tax Credit	19.85¢						20 years
Wind I (1.5MW to 2.99MW) with No Federal Tax Incentives	22.75¢						20 years
Wind II (3.0MW to 5.0MW) with Investment Tax Credit	18.20¢						20 years
Wind II (3.0MW to 5.0MW) with Production Tax Credit	19.45¢						20 years
Wind II (3.0MW to 5.0MW) with No Federal Tax Incentives	22.35¢						20 years
Anaerobic Digestion (150kW to 1,000kW) with Production Tax Credit	20.20¢						20 years

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Anaerobic Digestion (150kW to 1,000kW) with No Federal Tax Incentives	20.60¢						20 years
Small-Scale Hydropower I (10kW to 250kW) with Production Tax Credit	19.80¢						20 years
Small-Scale Hydropower I (10kW to 250kW) with No Federal Tax Incentives	21.35¢						20 years
Small-Scale Hydropower II (251kW to 1,000kW) with Production Tax Credit	18.55¢						20 years
Small-Scale Hydropower II (251kW to 1,000kW) with No Federal Tax Incentives	20.10¢						20 years

THE NARRAGANSETT ELECTRIC COMPANY
ACCESS AGREEMENT
FOR DISTRIBUTED GENERATION

This Service Agreement ("Agreement") is entered into by and between The Narragansett Company (the "Company") and ____ (the "Customer") with respect to the Customer's facilities at ____, _________________________ Rhode Island. Account Number(s):___________________________.

The Customer has interconnected a distributed generation ("DG") system pursuant to the Company's Standards for Connecting Distributed Generation tariff ("Interconnection Tariff") and has compensated the Company for the costs of interconnection as required by the Interconnection Tariff. The Customer's DG system does not operate to supply all or a portion of Customer's electricity needs at the Customer's service location at which the DG system is installed, but the output of the DG system, net of any electricity used to operate ancillary equipment or generate energy, is exported onto the Company's electric distribution system. The Customer is compensated for its energy output pursuant to the Company's Net Metering Tariff or its Renewable Growth Program for Non-Residential Customers tariff.

The Customer uses the Company's electric distribution system for the commercial operation of its DG system in order to transmit the electricity generated by the DG system into the Company's electrical system. The Company's electrical system must be constructed and maintained to allow for the Customer's use of such system in the manner required by the Customer. The Access Fee provides for the recovery of a Customer's proportionate share of the Company's costs of constructing and maintaining its system in providing this service to the Customer.

MONTHLY ACCESS CAPACITY

The Company limits the DG system's access under this Agreement to a capacity of _____kW ("Access Capacity"). The Access Capacity shall be the product of the DG system's nameplate capacity and an availability capacity factor applicable to the type of technology represented by the DG system. Nameplate capacity is the maximum rated output or gross output of a DG system. For a solar DG system, it is the total rated power output of all the DG system's panels, measured in direct current. The availability capacity factor to be applied to a DG system's nameplate capacity shall be as followed:

Solar	40%
Wind	To be Determined
Anaerobic Digestion	To be Determined
Hydropower	To be Determined

MONTHLY ACCESS FEE

The Monthly Access Fee shall be set at the rate per-kW below multiplied by Customer's Access Capacity identified above. The per-kW rate shall be determined based upon the voltage at which the DG system is interconnected to the Company's electrical system as follows:

Secondary	$7.25
Primary	$5.00

CONSTRUCTION ADVANCE PAYMENT

As discussed above, the Company's Interconnection Tariff shall apply to determine the Customer's cost of interconnecting its DG system to the Company's electrical system. The revenue derived from the Access Fee shall not be considered in determining the Customer's obligation to reimburse the Company for the cost to interconnect pursuant to the Interconnection Tariff.

TOTAL CUSTOMER MONTHLY PAYMENT

The total Customer monthly payment under the Company's Net Metering Provision or Renewable Energy Growth Program for Non-Residential Customers tariff is the Monthly Access Fee, as defined on page 1 of this Agreement.

The Customer agrees to pay the total Customer monthly payment each month in addition to the charges for its basic electric delivery service under the Net Metering Provision, Renewable Energy Growth Program for Non-Residential Customers tariff, and the applicable non-residential retail delivery service tariffs, as metered by the Company's metering device.

Notwithstanding the foregoing, the amount determined above is subject to change if the Public Utilities Commission approves a tariff with different pricing for this type of Access Service.

AGREEMENT TERM AND ASSIGNMENT

This Agreement becomes effective on the date of execution of the Agreement or the in-service date of the Customer's interconnection, whichever occurs later.

This Agreement may be terminated by one party providing 60 days advance written notice to the other, as a result of the DG system being disconnected from the Company's electric distribution system.

The Agreement between the Company and the Customer may be assigned to a third party by the Customer; provided that the third party agrees to assume all obligations of the Customer under this Agreement and that the Company consents to such assignment.

COMPANY LIABILITY

This Agreement fully incorporates the Limitation of Liability for Service Problems provision in the Company's Terms and Conditions for Distribution Service.

In Witness Whereof, the Company and the Customer have caused this Service Agreement to be executed by their duly authorized representatives.

___________________________(Customer)	The Narragansett Electric Company
By:_______________________	By:_____ _________________
Title:_____ ________________	Title:_____ ________________
Date:______________________	Date:______________________

Schedule NG - 16

Proposed Retail Delivery Service Tariffs and Proposed Tariff Provisions, Marked to Show Changes from Those Currently in Effect

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

AVAILABILITY

Electric delivery service under this rate is available for all domestic purposes in an individual private dwelling, an individual private apartment or an individual private condominium. Service is also available for farm customers where all electricity is delivered by the Company.

The Company may under unusual circumstances permit more than one set of living quarters to be served through one metering installation under this rate, but if so, the Customer Charge shall be multiplied by the number of separate living quarters so served.

Service under this rate is also available to residential condominium associations for service provided to common areas and facilities. The condominium association must provide documentation of the establishment of a residential condominium and a written statement identifying all buildings or units which are part of the condominium. Except at the Company's option, service to each individual unit shall be separately metered and billed apart from the common areas and facilities. If the Company permits more than one individual unit to be served through one metering installation, the Customer Charge shall be multiplied by the number of individual units served. Where a condominium includes space used exclusively for commercial purposes, all electric delivery service provided through the meter serving the commercial space will be charged at the appropriate commercial rate. Where a single metering installation records electric delivery service to both common areas/facilities and commercial space, all electric delivery service provided through the single meter will be billed under this rate. Electric delivery service provided to Company owned streetlights will be billed on the appropriate street and area lighting tariff.

A church and adjacent buildings owned and operated by the church may be served under this rate, but any such buildings separated by public ways must be billed separately.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Customer Charge, as defined below, and other applicable Retail Delivery Service Charges set forth in R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates.

CUSTOMER CHARGE

The Customer Charge will be based on a customer's monthly billed kWh according to the following schedule:

Tier	Total Monthly kWh	Monthly Charge
1	Less than 251 kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
2	251 – 750 kWh	
3	751 – 1,200 kWh	
4	1,201 kWh and greater	

The Customer Charge will be based upon the greater of 1) total monthly kWh in the current month or 2) the maximum monthly billed kWh during the preceding eleven months.

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under “Monthly Charge” may be adjusted from time to time in the manner described in the Company’s Transmission Service Cost Adjustment Provision.

Transition Charge Adjustment

The prices under this rate as set forth under “Monthly Charge” may be adjusted from time to time in the manner described in the Company’s Non-Bypassable Transition Charge Adjustment Provision.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company’s Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service.

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Energy Efficiency Program Provision as from time to time effective in accordance with law.

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company’s Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

THE NARRAGANSETT ELECTRIC COMPANY
BASIC RESIDENTIAL RATE (A-16)
RETAIL DELIVERY SERVICE

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff.

MINIMUM CHARGE

The minimum charge per month is the Customer Charge.

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: ~~February 1, 2013~~~~Month Year~~April 1. 2016

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

AVAILABILITY

This service shall apply to Customers in the class identified below:

(i) who receive all or any portion of their electric supply from non-emergency generation unit(s) with a nameplate rating greater than 30 kW ("Generation Units"), where electricity received by the Customer from the Generation Units is not being delivered over Company-owned distribution facilities pursuant to an applicable retail delivery tariff, and

(ii) who expect the Company to provide retail delivery service to supply the Customer's load at the service location when the Generation Units are not supplying all of that load.

Electric delivery service under this rate is applicable to customers with a facility demand of 25 kilowatts or more.

Customers who receive incentive payments for the installation of non-emergency generation units configured for Combined Heat and Power ("CHP") through the Company's approved Energy Efficiency Plan after the effective date of this tariff, and who would otherwise be eligible for this rate, will receive retail delivery service on General C&I Rate G-02 or Large Demand Rate G-32, as applicable.

All Customers served on this rate must elect to take their total electric delivery service under the metering installation as approved by the Company

EXEMPTION FOR CUSTOMER ACCOUNTS ASSOCIATED WITH ELIGIBLE NET METERING SYSTEMS

Customers accounts associated with Eligible Net Metering Systems, as defined in R.I Public Laws of 2011, Chapters 134 and 147, shall be exempt from back-up service rates commensurate with the size of the generating facility and subject to the statutory three (3) percent cap on the aggregate amount of net metering in Rhode Island.

TYPES OF SERVICE

"Back-Up" Retail Delivery Service consists of the Company standing ready to provide retail delivery service to the Customer's load when a non-emergency generator that supplies electricity to the Customer without using Company-owned distribution facilities does not supply all of the Customer's load.

"Supplemental" Retail Delivery Service is the delivery over Company-owned distribution facilities of electricity which is utilized at the Customer's facilities.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Back-Up Service Charges, and the Supplemental Service Charges, as stated below

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

DETERMINATION OF BILLING DEMAND FOR BILLING SUPPLEMENTAL AND BACK-UP per kW (DEMAND) CHARGES

The Billing Demand for each month for purposes of billing Back-Up and Supplemental Service shall be the greatest of the following:

1) The greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kW;

2) 90% of the greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kilovolt-amperes;

3) 75% of the greatest Demand as so determined above during the preceding eleven months.

BACK-UP RETAIL DELIVERY SERVICE

a) Rates for Back-Up Retail Delivery Service

Customer Charge per month	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kW	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

The Distribution Charge per kW applicable to Back-up Retail Delivery Service shall be equal to $~~6.96~~ 5.28 (representing the base distribution kW charge applicable to Back-up Service as approved in R.I.P.U.C. Docket No. 4658~~4323~~), plus the approved Operation and Maintenance and CapEx factors applicable to Back-up Service, both per the Company's approved Infrastructure Safety and Reliability Plan, multiplied by a factor of 10%, representing the likelihood that, on average, an outage of an individual customer's generator will occur coincident with the Company's distribution system peak demand approximately 10% of the time.

b) Determination of Back-Up Service Kilowatt Demand

The Back-Up Service Demand shall be the greater of:

1) the fifteen-minute reading from the Customer's generation meter(s) as measured in kilowatts at the time of the Billing Demand~~ in excess of 200 kW~~;
2) 90% of the fifteen-minute reading from the Customer's generation meter(s) as measured in kilovolt-amperes at the time of the Billing Demand~~ in excess of 200 kW~~; or
3) One hundred percent (100%) of the greatest Back-up Service Demand as determined above during the preceding eleven (11) months.

c) Installation of Meters on Generation

The Customer shall permit the Company to install meter(s) on the Generation Units providing electricity to the Customer, for purposes of billing under the terms of this rate. The meter shall be in accordance with the Company's reasonable specifications. The Customer will reimburse the Company for the

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

installed cost of the meter and any associated equipment. The Customer shall provide reasonable access to the Company during normal business hours to read such meter in order to bill the Customer for service under this rate.

PEAK AND OFF-PEAK PERIODS

PEAK HOURS:	June - September	-- 8 a.m. - 10 p.m. Weekdays,
	December - February	-- 7 a.m. - 10 p.m. Weekdays
	October – November and March - May	-- 8 a.m. - 9 p.m. Weekdays
OFF-PEAK HOURS:	All other hours	

Weekdays shall mean Monday through Friday, excluding the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Columbus Day (observed), Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

SUPPLEMENTAL RETAIL DELIVERY SERVICE

a) Rates for Supplemental Retail Delivery Service

Transmission Charge per kW	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kW ~~in excess of 200 kW~~	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Distribution Charge per kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Non-Bypassable Transition Charge per kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

b) Assessment of Kilowatt-hour Charges

For purposes of billing kWh charges for Supplemental Distribution and Transmission Service, Customers will be billed on the greater of (i) the actual kWh delivered by the Company or (ii) 90% of the actual kVAh delivered.

For purposes of billing kWh charges for Standard Offer Service, Non-Bypassable Transition Service and Energy Efficiency Programs, Customers will be billed on actual kWh delivered by the Company.

c) Determination of Kilowatt Demand

The Supplemental Distribution Service Demand for each month shall be the Billing Demand in excess of the Back-up Service Demand, but in no case less than 0 kW.

The Supplemental Transmission Service Demand for each month shall be the greater of:

1) The fifteen-minute peak from the meter(s) at the Customer's service entrance(s) as measured in

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

kW at the time of Billing Demand; or

2) 90% of the fifteen-minute peak demand from the meter(s) at the Customer's service entrance(s) as measured in kilovolt-amperes at the time of Billing Demand

OPTIONAL DETERMINATION OF DEMAND

A Customer who has been served under this rate for one year or more may upon written request have the Demand for each month used for Supplemental Service be based upon the greatest of items (1) and (2) set forth above for Billing Demand, beginning with the next month after such request and running for a period of not less than two consecutive months. In such case, the Distribution Charge per kW, the Distribution Charge per kWh, the Transmission Charge per kW and the Transmission Charge per kWh for Supplemental Service will be increased by 20% during any such period.

In addition, the Company may, at its discretion, agree to a lower demand determination for Back-Up Service below fifteen-minute peak coincident demand of the generation meter(s) if a Customer has installed equipment or configured its facilities in such a manner that automatically limits the requirement for Back-Up Service to the lower agreed-upon demand. Under such a situation, the Customer must demonstrate to the Company's reasonable satisfaction that the Customer's facilities are configured so as to limit the demand that can be placed on the distribution system, or must install and maintain, at no cost to the Company, an automated demand limiter or other similar device as agreed to by the Company which limits deliveries to the Customer over the Company's distribution system based on the lower agreed-upon demand. This equipment can not adversely affect the operation of the Company's distribution system or service to other customers. Such interruptible Back-Up Service shall be negotiated by the Customer and the Company under a separate contract which shall be specific to an individual customer's circumstances.

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Transition Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company's Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.

CREDIT FOR HIGH VOLTAGE DELIVERY

If the Customer takes delivery at the Company's supply line voltage, not less than 2400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit per

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

kilowatt of supplemental distribution billing demand for such month shall be allowed against the amount determined under the preceding provisions. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

An additional credit per kilowatt of the supplemental distribution billing demand for such month shall also be allowed if the Customer accepts delivery at not less than 115,000 volts, and the Company is saved the cost of installing any transformer and associated equipment. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

The total amount of the credit allowed under this provision shall not exceed the sum of the Customer Charge, the Distribution Charge per kW and the Distribution Charge per kWh.

HIGH-VOLTAGE METERING ADJUSTMENT

The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1% will be allowed from the amount determined under the preceding provisions.

SECOND FEEDER SERVICE

Except as provided below, Customers receiving second feeder service shall pay a charge per 90% of KVA of reserved second feeder capability. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates The charge for second feeder capability shall apply only to Customers with second feeder capability installed on or after May 1, 1998. The charge for second feeder capability shall not apply to Customers taking service within the Capital Center of Providence or within the downtown Providence underground network system. The Company's Construction Advance Policy 3 shall apply to determine any advance contribution by the customer, using an estimate of revenues to be derived from this second feeder rate. The Company reserves the right to decline second feeder service for engineering reasons.

An additional charge per 90% of KVA of reserved second feeder capability equal to the credit for high voltage delivery for customers taking service at not less than 2400 volts shall be charged if an additional transformer is required at the Customer's facility. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS

Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.

Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer

THE NARRAGANSETT ELECTRIC COMPANY
LARGE DEMAND BACK-UP SERVICE RATE (B-32)
RETAIL DELIVERY SERVICE

which were disallowed, including any interest required to be paid by the Company to such authority.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: ~~February 1, 2013~~April 1, 2016

Formatt
0.17", Fo

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~AVAILABILITY~~

~~This service shall apply to Customers in the class identified below:~~

(i) ~~who receive all or any portion of their electric supply from non-emergency generation unit(s) with a nameplate rating greater than 30 kW ("Generation Units"), where electricity received by the Customer from the Generation Units is not being delivered over Company-owned distribution facilities pursuant to an applicable retail delivery tariff, and~~

(ii) ~~who expect the Company to provide retail delivery service to supply the Customer's load at the service location when the Generation Units are not supplying all of that load.~~

~~Electric delivery service under this rate is applicable to those Customers who would otherwise be served under the Company's Optional Large Demand Rate G-62 if the Generation Units were not supplying electricity to the Customer.~~

~~Customers who receive incentive payments for the installation of non-emergency generation units configured for Combined Heat and Power ("CHP") through the Company's approved Energy Efficiency Plan after the effective date of this tariff, and who would otherwise be eligible for this rate, will receive retail delivery service on Large Demand Rate G-32 or Optional Large Demand Rate G-62.~~

~~All Customers served on this rate must elect to take their total electric delivery service under the metering installation as approved by the Company.~~

~~EXEMPTION FOR CUSTOMER ACCOUNTS ASSOCIATED WITH ELIGIBLE NET METERING SYSTEMS~~

~~Customers accounts associated with Eligible Net Metering Systems, as defined in R.I Public Laws of 2011, Chapters 134 and 147, shall be exempt from back-up service rates commensurate with the size of the generating facility and subject to the statutory three (3) percent cap on the aggregate amount of net metering in Rhode Island.~~

~~TYPES OF SERVICE~~

~~"Back-Up" Retail Delivery Service consists of the Company standing ready to provide retail delivery service to the Customer's load when a non-emergency generator that supplies electricity to the Customer without using Company-owned distribution facilities does not supply all of the Customer's load.~~

~~"Supplemental" Retail Delivery Service is the delivery over Company-owned distribution facilities of electricity which is utilized at the Customer's facilities.~~

~~MONTHLY CHARGE~~

~~The Monthly Charge will be the sum of the Back-Up Service Charges, and the Supplemental Service Charges, as stated below.~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~DETERMINATION OF BILLING DEMAND FOR BILLING SUPPLEMENTAL AND BACK-UP PER KW (DEMAND) CHARGES~~

~~The Billing Demand for each month for purposes of billing Back-Up and Supplemental Service shall be the greatest of the following:~~

~~1) The greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kW;~~

~~2) 90% of the greatest fifteen-minute peak coincident demand of the generation meter(s) plus the demand from the meter(s) at the Customer's service entrance(s) occurring in such month during Peak hours as measured in kilovolt-amperes;~~

~~3) 75% of the greatest Demand as so determined above during the preceding eleven months.~~

~~BACK-UP RETAIL DELIVERY SERVICE~~

~~a) Rates for Back-Up Retail Delivery Service~~

~~Customer Charge per month~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~
~~Distribution Charge per kW~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~The Distribution Charge per kW applicable to Back-up Retail Delivery Service shall be equal to $2.99 (representing the base distribution kW charge applicable to Back-up Service as approved in R.I.P.U.C. Docket No.4323), plus the approved Operation and Maintenance and CapEx factors applicable to Back-up Service, both per the Company's approved Infrastructure Safety and Reliability Plan, multiplied by a factor of 10%, representing the likelihood that, on average, an outage of an individual customer's generator will occur coincident with the Company's distribution system peak demand approximately 10% of the time.~~

~~b) Determination of Back-Up Service Kilowatt Demand~~

~~The Back-Up Service Demand shall be the greater of:~~

~~1) the fifteen-minute reading from the Customer's generation meter(s) as measured in kilowatts at the time of the Billing Demand;~~
~~2) 90% of the fifteen-minute reading from the Customer's generation meter(s) as measured in kilovolt-amperes at the time of the Billing Demand; or~~
~~3) One hundred percent (100%) of the greatest Back-up Service Demand as determined above during the preceding eleven (11) months.~~

~~c) Installation of Meters on Generation~~

~~The Customer shall permit the Company to install meter(s) on the Generation Units providing electricity~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~to the Customer, for purposes of billing under the terms of this rate. The meter shall be in accordance with the Company's reasonable specifications. The Customer will reimburse the Company for the installed cost of the meter and any associated equipment. The Customer shall provide reasonable access to the Company during normal business hours to read such meter in order to bill the Customer for service under this rate.~~

~~PEAK AND OFF-PEAK PERIODS~~

~~PEAK HOURS:~~	~~June – September~~	~~– 8 a.m. – 10 p.m. Weekdays,~~
	~~December - February~~	~~– 7 a.m. - 10 p.m. Weekdays~~
	~~October – November and~~	
	~~March – May~~	~~– 8 a.m. - 9 p.m. Weekdays~~
~~OFF-PEAK HOURS:~~	~~All other hours~~	

~~Weekdays shall mean Monday through Friday, excluding the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Columbus Day (observed), Labor Day, Veteran's Day, Thanksgiving Day and Christmas Day.~~

~~SUPPLEMENTAL RETAIL DELIVERY SERVICE~~

~~a) Rates for Supplemental Retail Delivery Service~~

~~Transmission Charge per kW~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~
~~Distribution Charge per kW~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~
~~Distribution Charge per kWh~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~
~~Non-Bypassable Transition Charge per kWh~~	~~See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~b) Assessment of Kilowatt-hour Charges~~

~~For purposes of billing kWh charges for Supplemental Distribution and Transmission Service, Customers will be billed on the greater of (i) the actual kWh delivered by the Company or (ii) 90% of the actual kVAh delivered.~~

~~For purposes of billing kWh charges for Standard Offer Service, Non-Bypassable Transition Service and Energy Efficiency Programs, Customers will be billed on actual kWh delivered by the Company.~~

~~c) Determination of Supplemental Service Kilowatt Demand~~

~~The Supplemental Distribution Service Demand for each month shall be the Billing Demand in excess of the Back-Up Service Demand, but in no case less than 0 kW.~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~The Supplemental Transmission Service Demand for each month shall be the greater of:~~

~~1) The fifteen-minute peak from the meter(s) at the Customer's service entrance(s) as measured in kW at the time of Billing Demand; or~~

~~2) 90% of the fifteen-minute peak demand from the meter(s) at the Customer's service~~

~~entrance(s) as measured in kilovolt-amperes at the time of Billing Demand~~

~~OPTIONAL DETERMINATION OF DEMAND~~

~~A Customer who has been served under this rate for one year or more may upon written request have the Demand for each month used for Supplemental Service be based upon the greatest of items (1) and (2) set forth above for Billing Demand, beginning with the next month after such request and running for a period of not less than two consecutive months. In such case, the Distribution Charge per kW, the Distribution Charge per kWh, the Transmission Charge per kW and the Transmission Charge per kWh for Supplemental Service will be increased by 20% during any such period.~~

~~In addition, the Company may, at its discretion, agree to a lower demand determination for Back-Up Service below fifteen-minute peak coincident demand of the generation meter(s) if a Customer has installed equipment or configured its facilities in such a manner that automatically limits the requirement for Back-Up Service to the lower agreed-upon demand. Under such a situation, the Customer must demonstrate to the Company's reasonable satisfaction that the Customer's facilities are configured so as to limit the demand that can be placed on the distribution system, or must install and maintain, at no cost to the Company, an automated demand limiter or other similar device as agreed to by the Company which limits deliveries to the Customer over the Company's distribution system based on the lower agreed-upon demand. This equipment can not adversely affect the operation of the Company's distribution system or service to other customers. Such interruptible Back-Up Service shall be negotiated by the Customer and the Company under a separate contract which shall be specific to an individual customer's circumstances.~~

~~RATE ADJUSTMENT PROVISIONS~~

~~Transmission Service Charge Adjustment~~

~~The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.~~

~~Transition Charge Adjustment~~

~~The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.~~

~~Standard Offer Adjustment~~

~~All Customers served on this rate must pay any charges required pursuant to the terms of the Company's~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.~~

~~Energy Efficiency Programs~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law. This provision shall not apply for Back-Up Retail Delivery Service and shall only apply to Supplemental Retail Delivery Service.~~

~~Infrastructure, Safety and Reliability Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.~~

~~Customer Credit Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Customer Credit Provision as from time to time effective in accordance with law.~~

~~LIHEAP Enhancement Plan Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.~~

~~Revenue Decoupling Mechanism Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.~~

~~Net Metering Provision and Qualifying Facilities Power Purchase Rate~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.~~

~~Pension Adjustment Mechanism Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism as from time to time effective in accordance with law.~~

~~STANDARD OFFER SERVICE~~

~~Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff. This provision shall not apply for Back-Up Retail Delivery Service~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~and shall only apply to Supplemental Retail Delivery Service.~~

~~CREDIT FOR HIGH VOLTAGE DELIVERY~~

~~If the Customer takes delivery at the Company's supply line voltage, not less than 2,400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit per kilowatt of supplemental distribution billing demand for such month shall be allowed against the amount determined under the preceding provisions. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~An additional credit per kilowatt of the supplemental distribution billing demand for such month shall also be allowed if the Customer accepts delivery at not less than 115,000 volts, and the Company is saved the cost of installing any transformer and associated equipment. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~The total amount of the credit allowed under this provision shall not exceed the sum of the Customer Charge, the Distribution Charge per kW and the Distribution Charge per kWh.~~

~~HIGH VOLTAGE METERING ADJUSTMENT~~

~~The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1% will be allowed from the amount determined under the preceding provisions.~~

~~SECOND FEEDER SERVICE~~

~~Except as provided below, Customers receiving second feeder service shall pay a charge per 90% of KVA of reserved second feeder capability. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates The charge for second feeder capability shall apply only to Customers with second feeder capability installed on or after May 1, 1998. The charge for second feeder capability shall not apply to Customers taking service within the Capital Center of Providence or within the downtown Providence underground network system. The Company's Construction Advance Policy 3 shall apply to determine any advance contribution by the customer, using an estimate of revenues to be derived from this second feeder rate. The Company reserves the right to decline second feeder service for engineering reasons.~~

~~An additional charge per 90% of KVA of reserved second feeder capability equal to the credit for high voltage delivery for customers taking service at not less than 2400 volts shall be charged if an additional transformer is required at the Customer's facility. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~GROSS EARNINGS TAX~~

~~A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.~~

~~GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS~~

~~Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND BACK-UP SERVICE RATE (B-62)
RETAIL DELIVERY SERVICE

~~Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer which were disallowed, including any interest required to be paid by the Company to such authority.~~

~~TERMS AND CONDITIONS~~

~~The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.~~

~~Effective: February 1, 2013~~

Formatt
1.5", Le

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

AVAILABILITY

Electric delivery service under this rate is available for all purposes. If electricity is delivered through more than one meter, except at the Company's option, the Monthly Charge for service through each meter shall be computed separately under this rate. Notwithstanding the foregoing, the Company may require any customer with a 12-month average demand greater than 200 kW to take service on the Large Demand Rate G-32.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Customer Charge, as defined below, and other applicable Retail Delivery Service Charges set forth in R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates .

CUSTOMER CHARGE

The Customer Charge will be based on a customer's monthly billed kWh according to the following schedule:

Tier	Total Monthly kWh	Monthly Charge
1	Up to 100 kWh	See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
2	101 – 700 kWh	
3	701 – 2,000 kWh	
4	2,001 kWh and greater	

The Customer Charge will be based upon the greater of 1) total monthly kWh in the current month or 2) the maximum monthly billed kWh during the preceding eleven months.

RATE ADJUSTMENT PROVISIONS

Transmission Service Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision.

Transition Charge Adjustment

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision.

Standard Offer Adjustment

All Customers served on this rate must pay any charges required pursuant to the terms of the Company's Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service.

Energy Efficiency Programs

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law.

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

Infrastructure, Safety and Reliability Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.

Customer Credit Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Customer Credit Provision as from time to time effective in accordance with law.

LIHEAP Enhancement Plan Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.

Revenue Decoupling Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.

Net Metering Provision and Qualifying Facilities Power Purchase Rate

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.

Pension Adjustment Mechanism Provision

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.

STANDARD OFFER SERVICE

Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff.

MINIMUM CHARGE

Metered Service: See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates
Unmetered Service: See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates

However, if the kVA transformer capacity needed to serve a customer exceeds 25 kVA, the minimum charge will be increased for each kVA in excess of 25 kVA. See Additional Minimum Charge, R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates.

THE NARRAGANSETT ELECTRIC COMPANY
SMALL C&I RATE (C-06)
RETAIL DELIVERY SERVICE

UNMETERED ELECTRIC SERVICE

Unmetered services are usually not permitted or desirable. However, the Company recognizes that there are certain instances where metering is not practical. Examples of such locations are telephone booths and fire box lights. The monthly bill will be computed by applying the rate schedule to a use determined by multiplying the total load in kilowatts by 730 hours. However, the energy use may be adjusted after tests of the unmetered equipment indicate lesser usage. When unmetered service is provided the aforestated customer charge will be waived and the Unmetered Service Charge per month per location will be implemented.

GROSS EARNINGS TAX

A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.

GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS

Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.

Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer which were disallowed, including any interest required to be paid by the Company to such authority.

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective: ~~Month, Year~~April 1, 2016

Format

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND RATE (G-62)
RETAIL DELIVERY SERVICE

~~**AVAILABILITY**~~

~~Electric delivery service shall be taken under this rate for all purposes by any customer who is placed on the rate by the Company in accordance with this paragraph. This rate is optional for any customer who has a 12-month maximum Demand of 5,000 kW or greater.~~

~~If electricity is delivered through more than one meter, except at the Company's option, the Monthly Charge for service through each meter shall be computed separately under this rate. If any electricity is delivered hereunder at a given location, then all electricity delivered by the Company at such location shall be delivered hereunder.~~

~~This rate will apply to customers who receive incentive payments for the installation of non-emergency generation configured to provide Combined Heat and Power ("CHP") through the Company's approved Energy Efficiency Plan after the effective date of this tariff, and who would otherwise be eligible to receive service on Optional Large Demand Back-up Service Rate B-62.~~

~~This rate is also available to customer accounts associated with Eligible Net Metering Systems, as defined in R.I Public Laws of 2011, Chapters 134 and 147, who are therefore exempt from the backup service rates. However, any customer exempted from the backup service rates under this provision shall nevertheless be required to install metering pursuant to the backup service tariff that shall provide information on the operation of the generation unit.~~

~~**MONTHLY CHARGE**~~

~~The Monthly Charge will be the sum of the Retail Delivery Service Charges set forth in R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates.~~

~~**PEAK, SHOULDER AND OFF-PEAK PERIODS**~~

~~PEAK HOURS:~~	~~June - September~~	~~-- 8 a.m. - 10 p.m. Weekdays,~~
	~~December - February~~	~~-- 7 a.m. - 10 p.m. Weekdays~~
	~~October – November and March - May~~	~~-- 8 a.m. - 9 p.m. Weekdays~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND RATE (G-62)
RETAIL DELIVERY SERVICE

~~OFF-PEAK HOURS: All other hours~~

~~Weekdays shall mean Monday through Friday, excluding the following holidays: New Year's Day, President's Day, Memorial Day, Independence Day, Columbus Day (observed), Labor Day, Veteran's Day, Thanksgiving Day and Christmas Day.~~

~~**RATE ADJUSTMENT PROVISIONS**~~

~~Transmission Service Charge Adjustment~~

~~The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Transmission Service Cost Adjustment Provision.~~

~~Transition Charge Adjustment~~

~~The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner described in the Company's Non-Bypassable Transition Charge Adjustment Provision.~~

~~Standard Offer Adjustment~~

~~All Customers served on this rate must pay any charges required pursuant to the terms of the Company's Standard Offer Adjustment Provision, whether or not the Customer is taking or has taken Standard Offer Service.~~

~~Energy Efficiency Programs~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Energy Efficiency Program Provision as from time to time effective in accordance with law.~~

~~Infrastructure, Safety and Reliability Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Infrastructure, Safety and Reliability Provision as from time to time effective in accordance with law.~~

~~Customer Credit Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Customer Credit Provision as from time to time effective in accordance with law.~~

~~LIHEAP Enhancement Plan Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's LIHEAP Enhancement Plan Provision as from time to time effective in accordance with law.~~

~~Revenue Decoupling Mechanism Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Revenue Decoupling Mechanism Provision as from time to time effective in accordance with law.~~

Formatt
1.5", Le
Not at 1

Formatt
1.5", Le

Formatt
4", Left

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND RATE (G-62)
RETAIL DELIVERY SERVICE

~~Net Metering Provision and Qualifying Facilities Power Purchase Rate~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Net Metering Provision and Qualifying Facilities Power Purchase Rate as from time to time effective in accordance with law.~~

~~Pension Adjustment Mechanism Provision~~

~~The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Pension Adjustment Mechanism Provision as from time to time effective in accordance with law.~~

~~STANDARD OFFER SERVICE~~

~~Any Customer served under this rate who is eligible for Standard Offer Service shall receive such service pursuant to the Standard Offer Service tariff.~~

~~DEMAND~~

~~The Demand for each month under ordinary load conditions shall be the greatest of the following:~~

~~a) The greatest fifteen-minute peak occurring in such month during Peak hours as measured in kilowatts,~~
~~b) 90% of the greatest fifteen-minute peak occurring in such month during Peak hours as measured in kilovolt-amperes,~~
~~c) 75% of the greatest Demand as so determined above during the preceding eleven months, and~~
~~d) 10 kilowatts.~~

~~Any Demand established during the Scheduled Maintenance Period, as defined below, will not be considered during billing periods subsequent to the Scheduled Maintenance Period in the calculation of c) above.~~

~~OPTIONAL DETERMINATION OF DEMAND~~

~~A Customer who has been served hereunder for one year or more may upon written request have the Demand for each month, beginning with the next month after such request and running for a period of not less than two consecutive months, be based upon the greatest of items (a), (b) and (d) above. In such case, the Distribution Charge per kW, the Transmission Charge per kW and the Transmission per kWh will be increased by 20% during any such period.~~

~~COMBINED HEAT AND POWER ("CHP") PROVISIONS~~

~~Minimum Demand~~

~~Customers who receive an incentive payment for the installation of a CHP non-emergency generation unit through the Company's Energy Efficiency Program after the effective date of this tariff will be subject to a monthly Minimum Demand Charge. For Customer's subject to this CHP Minimum Demand Provision, the monthly Demand~~

~~will be the greater of:~~

~~a) the Demand as determined above; or~~

~~b) the Minimum Demand, which shall be 50% of the greatest fifteen-minute reading from the Customer's generation meter(s) as measured in kilowatts during peak hours;~~

~~The Customer Charge, Transmission Demand Charge, all per kWh charges and any other applicable charges and credits will be in addition to the Minimum Demand Charge.~~

~~Scheduled Maintenance~~

~~Customers may, at their option, request one annual Scheduled Maintenance Period which may occur during no more than five (5) consecutive week-days during the months of April, May, October and November. This request must be submitted to the Company in writing at least 30 days in advance, and must specify the exact dates and duration of the Scheduled Maintenance Period. The Company will notify the Customer in writing within five (5) business days of receiving the Customer's request whether the Scheduled Maintenance Period is acceptable. Meter readings during this Scheduled Maintenance Period will be used in determining the Customer's Demand for the current month, but will not be used during subsequent billing periods for purposes of determining Demand (See Demand above).~~

~~Metering Requirements~~

~~The Customer shall permit the Company to install meter(s) on the Generation Units providing electricity to the Customer, for purposes of billing under the terms of this rate. The meter shall be in accordance with the Company's reasonable specifications. The Customer will reimburse the Company for the installed cost of the meter and any associated equipment. The Customer shall provide reasonable access to the Company during normal business hours to read such meter in order to bill the Customer for service under this rate.~~

~~**CREDIT FOR HIGH VOLTAGE DELIVERY**~~

~~If the Customer takes delivery at the Company's supply line voltage, not less than 2,400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit per kilowatt of billing demand for such month shall be allowed against the amount determined under the preceding provisions. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~An additional credit per kilowatt of the billing demand for such month shall also be allowed if said customer accepts delivery at not less than 115,000 volts, and the Company is saved the cost of installing any transformer and associated equipment. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~The total amount of the credit allowed under this provision shall not exceed the sum of the Customer Charge, the Distribution Charge per kW and the Distribution Charge per kWh.~~

~~**HIGH-VOLTAGE METERING ADJUSTMENT**~~

~~The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a~~

THE NARRAGANSETT ELECTRIC COMPANY
OPTIONAL LARGE DEMAND RATE (G-62)
RETAIL DELIVERY SERVICE

~~discount of 1% will be allowed from the amount determined under the preceding provisions.~~

~~SECOND FEEDER SERVICE~~

~~Except as provided below, Customers receiving second feeder service shall pay a charge per 90% of KVA of reserved second feeder capability. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates. The charge for second feeder capability shall apply only to Customers with second feeder capability installed on or after May 1, 1998. The charge for second feeder capability shall not apply to Customers taking service within the Capital Center of Providence or within the downtown Providence underground network system. The Company's Construction Advance Policy 3 shall apply to determine any advance contribution by the customer, using an estimate of revenues to be derived from this second feeder rate. The Company reserves the right to decline second feeder service for engineering reasons.~~

~~An additional charge per 90% of KVA of reserved second feeder capability equal to the credit for high voltage delivery for customers taking service at not less than 2400 volts shall be charged if an additional transformer is required at the Customer's facility. See R.I.P.U.C. No. 2095, Summary of Retail Delivery Rates~~

~~GROSS EARNINGS TAX~~

~~A Rhode Island Gross Earnings Tax adjustment will be applied to the charges determined above in accordance with Rhode Island General Laws.~~

~~GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS~~

~~Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will be exempt from the Gross Earnings Tax to the extent allowed by the Division of Taxation.~~

~~Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(7) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer which were disallowed, including any interest required to be paid by the Company to such authority.~~

~~TERMS AND CONDITIONS~~

~~The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.~~

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.

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.

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%

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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 projects in the upcoming program year~~.~~; and

~~v)~~vi) Incremental costs incurred to implement and communicate to customers the rates resulting from the rate design review approved by the Commission pursuant to § 39-26.6-24. Incremental costs include changes to the Company's billing system and the cost of communicating and otherwise notifying customers of any changes resulting from the rate design review beyond the customer communications the Company typically undertakes during the year.

4. RATE

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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:

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

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;

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;

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~~

~~3)~~4) all incremental costs necessary to meet program objectives or make billing system improvements to

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

implement RE Growth Program pursuant to Section 3.vi) above; and

~~4)~~5) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i) above.~~;~~

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:

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

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:

(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;

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM COST RECOVERY PROVISION

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

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

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

~~4)~~5) all incremental costs necessary to implement and communicate rate changes as a result of the rate design review pursuant to Section 3.vi);

~~5)~~6) the costs incurred during the Reconciliation Period by the Company pursuant to Section 3.i); and

~~6)~~7) 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 = 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

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

THE NARRAGANSETT ELECTRIC COMPANY
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: April 1, ~~2015~~2016

THE NARRAGANSETT ELECTRIC COMPANY
NET METERING PROVISION

I. Definitions

"Commission" shall mean the Rhode Island Public Utilities Commission.

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

"Eligible Net Metering Resource" shall mean eligible renewable energy resource as defined in RIGL Section 39-26-5 including biogas created as a result of anaerobic digestion, but, specifically excluding all other listed eligible biomass fuels.

"Eligible Net Metering System" shall mean a facility generating electricity using an Eligible Net Metering Resource that is reasonably designed and sized to annually produce electricity in an amount that is equal to or less than the Renewable Self-generator's usage at the Eligible Net Metering System Site measured by the three (3) year average annual consumption of energy over the previous three (3) years at the electric distribution account(s) located at the Eligible Net Metering System Site. A projected annual consumption of energy may be used until the actual three (3) year average annual consumption of energy over the previous three (3) years at the electric delivery service account(s) located at the Eligible Net Metering System Site becomes available for use in determining eligibility of the generating system. Schedule B of this tariff is required to be filled out completely to determine eligibility of the above accounts. The Eligible Net Metering System must be owned by the same entity that is the customer of record on the Net Metered Accounts. Notwithstanding any other provisions of this tariff, any Eligible Net Metering Resource: (i) owned by a Public Entity or Multi-municipal Collaborative or (ii) owned and operated by a renewable generation developer on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement shall be treated as an Eligible Net Metering System and all delivery service accounts designated by the Public Entity or Multi-municipal Collaborative for net metering shall be treated as accounts eligible for net metering within an Eligible Net Metering System Site.

"Eligible Net Metering System Site" shall mean the site where the Eligible Net Metering System is located or is part of the same campus or complex of sites contiguous to one another and the site where the Eligible Net Metering System is located or a farm in which the Eligible Net Metering System is located. Except for an Eligible Net Metering System owned by or operated on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, the purpose of this definition is to reasonably assure that energy generated by the Eligible Net Metering System is consumed by net metered electric delivery service account(s) that are actually located in the same geographical location as the Eligible Net Metering System. Except for an Eligible Net Metering System owned by or operated on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, all of the Net Metered Accounts at the Eligible Net Metering System Site must be the accounts of the same customer of record and customers are not permitted to enter into agreements or arrangements to change the name on accounts for the purpose of artificially expanding the Eligible Net Metering System Site to contiguous sites in an attempt to avoid this restriction. However, a property owner may change the nature of the metered service at the delivery service accounts at the site to be master metered (as allowed by applicable state law) in the owner's name, or become the customer of record for each of the delivery service accounts, provided that the owner becoming the customer of record actually owns the property at which the delivery service account is located. As long as the Net Metered Accounts meet the requirements set forth in this definition, there is no limit on the number of delivery service accounts that may be net metered within the Eligible Net Metering System Site. Schedule B of this tariff is required to be filled out completely to determine eligibility of the above accounts.

"Excess Renewable Net Metering Credit" shall mean a credit that applies to an Eligible Net Metering System for that portion of the Renewable Self-generator's production of electricity beyond one hundred percent (100%) and no greater than one hundred twenty-five percent (125%) of the Renewable Self-generator's own consumption at the Eligible Net Metering System Site during the applicable billing period. Such Excess Renewable Net Metering Credit shall be equal to the Company's avoided cost rate, defined for this purpose as the Standard Offer Service kilowatt-hour (kWh) charge for the rate class and time-of-use billing period, if applicable, applicable to the delivery service account(s) at the Eligible Net Metering System Site. Where there are delivery service accounts at the Eligible Net Metering System Site in different rate classes, the Company may calculate the Excess Renewable Net Metering Credit based on the average of the Standard Offer Service rates applicable to those on-site delivery service accounts. The Company has the option to use the energy received from such excess generation to serve the Standard Offer Service load. The Commission shall have the authority to make determinations as to the applicability of this credit to specific generation facilities to the extent there is an uncertainty or disagreement.

"Farm" shall be defined in accordance with RIGL Section 44-27-2, except that all buildings associated with the Farm shall be eligible for Renewable Net Metering Credits and Excess Renewable Net Metering Credits as long as: (i) the buildings are owned by the same entity operating the Farm or persons associated with operating the Farm; and (ii) the buildings are on the same farmland as the project on either a tract of land contiguous with or reasonably proximate to such farmland or across a public way from such farmland.

"ISO-NE" shall mean the Independent System Operator New England, Inc. established in accordance with the NEPOOL Agreement and applicable Federal Energy Regulatory Commission approvals, which is responsible for managing the bulk power generation and transmission systems in New England.

"Multi-municipal Collaborative" shall mean a group of towns and/or cities that enter into an agreement for the purpose of co-owning a renewable generation facility or entering into a Public Entity Net Metering Financing Arrangement.

"Municipality" shall mean any Rhode Island town or city, including any agency or instrumentality thereof, with the powers set forth in Title 45 of the general laws.

"NEPOOL" shall mean New England Power Pool.

"Net Metered Accounts" shall mean one or more electric delivery service accounts owned by a single customer of record on the same campus or complex of sites contiguous to one another and the site where the Eligible Net Metering System is located or a Farm in which the Eligible Net Metering System is located, or all municipal delivery service accounts associated with an Eligible Net Metering System that is: (i) owned by a Public Entity or Multi-municipal Collaborative or (ii) owned and operated by a renewable generation developer on behalf of a Public Entity or Multi-municipal Collaborative through a Public Entity Net Metering Financing Arrangement, provided that the Net Metering Customer or the Public Entity or Multi-municipal Collaborative has submitted Schedule B (attached) with the individual billing account information for each Net Metered Account. Should there be a change to any of the information contained therein, it is the responsibility of the Net Metering Customer or the Public Entity or Multi-municipal Collaborative to submit a revised Schedule B in order for the Company to determine eligibility for the accounts 30 days prior to making any such change.

"Net Metering" shall mean using electricity generated by an Eligible Net Metering System for the purpose of self-supplying power at the Eligible Net Metering System Site and thereby offsetting consumption at the Eligible Net Metering System Site through the netting process established in this provision.

"Net Metering Customer" shall mean a customer of the Company receiving and being billed for electric delivery service whose delivery account(s) are being net metered.

"Person" shall mean an individual, firm, corporation, association, partnership, farm, town or city of the State of Rhode Island, Multi-municipal Collaborative, or the State of Rhode Island or any department of the state government, governmental agency or public instrumentality of the state.

"Project" shall mean a distinct installation of an Eligible Net Metering System. An installation will be considered distinct if it is installed in a different location, or at a different time, or involves a different type of renewable energy.

"Public Entity" means the State of Rhode Island, Municipalities, wastewater treatment facilities, public transit agencies or any water distributing plant or system employed for the distribution of water to the consuming public within the State of Rhode Island including the water supply board of the City of Providence.

"Public Entity Net Metering Financing Arrangement" shall mean arrangements entered into by a Public Entity or Multi-municipal Collaborative with a private entity to facilitate the financing and operation of a Net Metering resource, in which the private entity owns and operates an Eligible Net Metering Resource on behalf of a Public Entity or Multi-municipal Collaborative, where: (i) the Eligible Net Metering Resource is located on property owned or controlled by the Public Entity or one of the Municipalities, as applicable, and (ii) the production from the Eligible Net Metering Resource and primary compensation paid by the Public Entity or Multi-municipal Collaborative to the private entity for such production is directly tied to the consumption of electricity occurring at the designated Net Metered Accounts.

"Renewable Net Metering Credit" shall mean a credit that applies to an Eligible Net Metering System up to one hundred percent (100%) of the Renewable Self-generator's usage at the Eligible Net Metering System Site over the applicable billing period. This credit shall be equal to the total kilowatt-hours of electricity generated and consumed on-site during the billing period multiplied by the sum of the:

(i) Standard Offer Service kilowatt-hour charge for the rate class applicable to the net metering customer;
(ii) Distribution kilowatt-hour charge;
(iii) Transmission kilowatt-hour charge; and
(iv) Transition kilowatt-hour charge.

"Renewable Self-generator" shall mean an electric delivery service customer who installs or arranges for an installation of renewable generation that is primarily designed to produce electricity for consumption by that same customer at its delivery service account(s).

II. Terms and Conditions

The following policies regarding Net Metering of electricity from Eligible Net Metering Systems and regarding any Person that is a Renewable Self-generator shall apply:

1. The maximum allowable capacity for Eligible Net Metering Systems, based on name plate capacity, shall be five megawatts (5 MW).

2. For ease of administering Net Metered Accounts and stabilizing Net Metered Account bills, the Company may elect (but is not required) to estimate for any twelve (12) month period i) the production from the Eligible Net Metering System and ii) aggregate consumption of the Net Metered Accounts at the Eligible Net Metering System Site and establish a monthly billing plan that reflects the expected Renewable Generation Credits and Excess Renewable Generation Credits that would be applied to the Net Metered Accounts over twelve (12) months. The billing plan would be designed to even out monthly billings over twelve (12) months, regardless of actual production and usage. If such election is made by the Company, the Company would reconcile payments and credits under the billing plan to actual production and consumption at the end of the twelve (12) month period and apply any credits or charges to the Net Metered Accounts for any positive or negative difference, as applicable. Should there be a material change in circumstances at the Eligible Net Metering System Site or associated Net Metered Accounts during the twelve (12) month period, the estimate and credits may be adjusted by the Company during the reconciliation period. The Company also may elect (but is not required) to issue checks to any Net Metering Customer in lieu of billing credits or carry forward credits or charges to the next billing period. For residential Eligible Net Metering Systems twenty-five kilowatts (25 kW) or smaller, the Company, at its option, may administer Renewable Net Metering Credits month to month allowing unused credits to carry forward into following billing period.

3. If the electricity generated by an Eligible Net Metering System during a billing period is equal to or less than the Net Metering Customer's usage during the billing period for Net Metered Accounts at the Eligible Net Metering System Site, the customer shall receive Renewable Net Metering Credits, which shall be applied to offset the Net Metering Customer's usage on Net Metered Accounts at the Eligible Net Metering System Site.

4. If the electricity generated by an Eligible Net Metering System during a billing period is greater than the Net Metering Customer's usage on Net Metered Accounts at the Eligible Net Metering System Site during the billing period, the customer shall be paid by Excess Renewable Net Metering Credits for the excess electricity generated beyond the Net Metering Customer's usage at the Eligible Net Metering System Site up to an additional twenty-five percent (25%) of the Renewable Self-generator's consumption during the billing period; unless the Company and Net Metering Customer have agreed to a billing plan pursuant to Section II.2.

5. As a condition to receiving Renewable Generation Credits or Excess Renewable Generation Credits pursuant to this provision, customers who install Eligible Net Metering Systems must enter into an interconnection agreement and comply with the Company's Standards for Connecting Distributed Generation, as amended and superseded from time to time.

6. Customers eligible to receive Renewable Net Metering Credits or Excess Renewable Net Metering Credits pursuant to Sections II.3 and II.4, respectively, shall be required to complete Schedule B.

7. As a condition to receiving any payments pursuant to this provision, customers who install Eligible Net Metering Systems with a nameplate capacity in excess of 25 kW must comply with any and all applicable NEPOOL and ISO-NE rules, requirements, or information requests that are necessary for the Eligible Net Metering System's electric energy output to be sold into the ISO-NE administered markets. If the Company must provide to NEPOOL or ISO-NE any information regarding the operation, output, or any other data in order to sell the output of the Eligible Net Metering System into the ISO-NE administered markets, the customer who installs an Eligible Net Metering System must provide such information to the Company prior to the project being authorized to operate in parallel with the Company's electric distribution system.

8. NEPOOL and ISO-NE have the authority to impose fines, penalties, and/or sanctions on participants if it is determined that a participant is violating established rules in certain instances. Accordingly, to the extent that a fine, penalty, and/or sanction is levied by NEPOOL or the ISO-NE as a result of the Owner of the Eligible Net Metering System's failure to comply with a NEPOOL or ISO-NE rule, requirement or information request, the Eligible Net Metering System will be responsible for the costs incurred by the Company, if any, associated with such fine, penalty and/or sanction.

III. Rates for Distribution Service to Eligible Net Metering System and Net Metered Accounts

1. Retail delivery service by the Company to the Eligible Net Metering System and Net Metered Accounts shall be governed by the tariffs, rates, terms, conditions, and policies for retail delivery service which are on file with the Commission.

2. The Standard Offer Service and retail delivery rates applicable to any Net Metered Account shall be the same as those that apply to the rate classification that would be applicable to such delivery service account in the absence of Net Metering, including customer and demand charges, and no other charges may be imposed to offset Net Metering Credits.

3. Net Metered Accounts associated with an Eligible Net Metering System shall be exempt from backup service rates commensurate with the size of the Eligible Net Metering System.

4. The account associated with an Eligible Net Metering System where the Eligible Net Metering System is geographically segregated from the Eligible Net Metering Site and Net Metering Accounts shall be subject to an Access Fee for the use of the Company's distribution system by the Eligible Net Metering System for the purpose of exporting electricity generated by the Eligible Net Metering System into the electric distribution system. The Access Fee shall be a fixed per-kilowatt charge assessed monthly and shall be applied to a fixed capacity value determined as the nameplate capacity of the Eligible Net Metering System adjusted by a capacity factor applicable to the Eligible Net Metering System's technology. The customer of record of the account associated with the Eligible Net Metering System must execute an Access Service Agreement and be subject to its terms and conditions. The Access Fee does not alter the obligations for the interconnection of the Eligible Net Metering System to the Company's electric distribution system as provided in II.5 above.

   The Access Fee per-kilowatt shall be $7.25 for Eligible Net Metering Systems interconnected to the Company's secondary voltage distribution system and $5.00 for Eligible Net Metering Systems interconnected to the Company's primary voltage distribution system.

IV. Cost Recovery

1. Any prudent and reasonable costs incurred by the Company pursuant to achieving compliance with RIGL Section 39-26.2-3(a) and the annual amount of any Renewable Net Metering Credits or Excess Renewable Net Metering Credits provided to Eligible Net Metering Systems, shall be aggregated by the Company and billed to all distribution customers on an annual basis through a uniform per kilowatt hour (kWh) Net Metering Charge embedded in the distribution component of the rates reflected on customer bills.

2. The Company will include the energy market payments received from ISO-NE for the electricity generated by Eligible Net Metering Systems in the Company's annual reconciliation of the Net Metering Charge. Eligible Net Metering Systems with a nameplate capacity in excess of 25 kW shall provide all necessary information to, and cooperate with, the Company to enable the Company to obtain the appropriate asset identification for reporting generation to ISO-NE. The Company will report all exported power to the ISO-NE as a settlement only generator and net this reported usage and associated payment received against the annual amount of Standard Offer Service component of any Renewable Net Metering Credits or Excess Renewable Net Metering Credits provided to accounts associated with Eligible Net Metering Systems.

Effective: April 1, ~~2015~~2016

Schedule B – Additional Information Required for Net Metering Service

THE NARRAGANSETT ELECTRIC COMPANY
NET-METERING APPLICATION OF CREDITS

Customer Name: ____

Account Number: ____

Facility Address: ____

City: ______________________ State: RI Zip Code: _____________

The Agreement is between ______________________________, a Net-Metered Customer ("NMC") and The Narragansett Electric Company (the "Company") for application of credits earned through net-metering from the NMC located at ______________________________, Rhode Island.

The NMC agrees to comply with the provisions of the Net-Metering Provision, the applicable retail delivery tariffs and the Terms and Conditions for Distribution Service that are on file with the Rhode Island Public Utilities Commission as currently in effect or as modified, amended, or revised by the Company, and to pay any metering and interconnection costs required under such tariff and policies.

A.) NMC Address: _______________________

____

____

Nameplate rating (AC) of the Eligible Net Metering System _______________kWs
Estimated annual generation in kWhs of Eligible Net-Metering System ______kWhs

Net Metered Account(s)

The following information must be provided for each individual Net Metered Account in a proposed Eligible Net Metering site:

Name: ______________________________________ (Except in the case of a Public Entity or Multi-municipal Collaborative, the customer of record must be the same as the NMC)

Service Address: ____________________________________

National Grid Account number: _______________________

Three (3) years average kWh usage for this account __________________

Total three (3) years average kWh usage for all accounts listed as an Eligible Net Metering Site __________

Once this information is received, the Company will determine if the accounts listed are eligible for net metering.

B.) For any Billing Period in which the NMC earns Net Metering Credits, please indicate how the Distribution Company will apply them:

- ☐ Apply all of the Net Metering Credits to the account of the NMC (skip Items C and D below)
- ☐ Allocate all the Net Metering Credits to the accounts of eligible Customers (please fill out C and D below)
- ☐ Both apply a portion of the Net Metering Credits to the NMC's account and allocate a portion to the accounts of eligible Customers (please fill out C and D below)

The Company will notify the NMC within 30 days of the Company's receipt of Schedule B whether it will allocate or purchase Net Metering Credits. If the Company elects to purchase Net Metering Credits, the Company will render payment by issuing a check to the NMC each Billing Period, unless otherwise agreed in writing by the NMC and Company. If the Company elects to allocate Net Metering Credits, the NMC must complete Item C and submit the revised Schedule B to the Company.

C.) Please state the total percentage of Net Metering Credits to be allocated.

% Amount of the Net Metering Credit being allocated.

The total amount of Net Metering Credits being allocated shall not exceed 100%. Any remaining percentage will be applied to the NMC's account.

Please identify each eligible Customer account to which the NMC is allocating Net Metering Credits by providing the following information (attach additional pages as needed):

NOTE: If a designated Customer account closes, the allocated percentage will revert to the NMC's account, unless otherwise mutually agreed in writing by the NMC and the Company.

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

Name:
Billing Address:
Account number:
Amount of the Net Metering Credit: _____%

D.) The terms of this Schedule B shall remain in effect unless and until the NMC executes a revised Schedule B and submits it to the Company. Unless otherwise required herein or mutually agreed to in writing by the NMC and the Company, a revised Schedule B shall not be submitted more than once in any given calendar year.

E.) A signature on the application shall constitute certification that (1) the NMC has read the application and knows its contents; (2) the contents are true as stated, to the best knowledge and belief of the NMC; and (3) the NMC possesses full power and authority to sign the application.

Notice

Execution of this agreement will cancel any previous agreement for the net-metered account under the Net-Metering Provision.

The Company or NMC may terminate this agreement on thirty (30) days written notice, which includes a statement of reasons for such termination. In addition, the NMC must re-file this agreement annually.

Agreed and Accepted – Please sign

[**NAME OF NMC**] Date: ____________________

By:____

Name:
Title:

The Narragansett Electric Company Date: ___________________
d/b/a National Grid

By:____

Name:
Title:

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

1. **Introduction**

This tariff ("Tariff") describes the terms and conditions under which an Applicant for an eligible distributed generation project ("DG Project") will receive funding pursuant to Chapter 26.6 of Title 39 of the Rhode Island General Laws ("Chapter 26.6"), which refers to the Renewable Energy Growth Program ("RE Growth Program").

This Tariff will apply to an Applicant who has installed a DG Project at a Non-Residential Customer's service location or another location that allows for interconnection to the Company's electric distribution system. For this purpose, a Non-Residential Customer ("Customer") is defined as a customer receiving retail delivery service on any rate schedule other than the Company's residential rate schedules (Basic Residential Rate A-16 and Low Income Rate A-60). This Tariff will also apply to a DG Project that does not provide On-Site Use to a Customer receiving retail delivery service from the Company. The Applicant and the Customer may be the same person, or different persons, subject to the eligibility standards in the Solicitation and Enrollment Process Rules ("Rules") and this Tariff.

This Tariff applies to the Applicant for a DG Project that is awarded a Certificate of Eligibility by the Commission or the Company pursuant to the Rules, and any successor Applicant for the Project. Upon being awarded a Certificate of Eligibility, a DG Project has a defined period to meet all requirements to receive compensation pursuant to this Tariff, which is: (1) 48 months for a Small DG Project using hydropower; (2) 36 months for a Project using anaerobic digestion; or (3) 24 months for a Project using another eligible technology.

The Applicant is required to update the Application information for the DG Project, including but not limited to information concerning: the DG Project owner, the Customer, the electric service account, and the recipient of Performance-Based Incentive Payments. Also, an Applicant may designate a successor Applicant for a DG Project under this Tariff with notice to the Company and without the consent of the Company. The Applicant may, but need not be, the same person or entity to pursue the interconnection of the DG Project with the Company's electric distribution system. The Applicant maintains the obligation to ensure that all aspects of a DG Project comply with the terms of the Company's Solicitation and Enrollment Process Rules and this Tariff. Upon notice to the Company, the Applicant may transfer the compensation under this Tariff to another person or entity without the consent of the Company.

2. **Definitions**

The following words and terms shall have the following meanings when used in this Tariff:

a. Applicant: the person or entity with legal authority to enroll the DG Project in the RE Growth program, and with the obligation to ensure that all aspects of the DG Project comply with the Rules.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

b. Application: the RE Growth Program Enrollment short form application submitted by the Applicant.

c. Board: the Distributed Generation Board established pursuant to R.I. Gen. Laws § 39-26.2-10 and having expanded responsibilities under Chapter 26.6.

d. Ceiling Price: the bidding price cap applicable to an enrollment in a given Renewable Energy Class and Program Year. Ceiling prices will be recommended by the Board and approved by the Commission.

e. Certificate of Eligibility: written notice by the Company or Commission that a DG Project has been enrolled in the RE Growth Program. Upon an award of a Certificate of Eligibility, a DG Project will be entitled to receive Performance-Based Incentive Payments for a specified term, pursuant to the terms and conditions of the applicable Tariff supplement.

f. Commercial-Scale Solar Project: a solar DG Project with a nameplate capacity greater than 250 kilowatts (250 kW) but less than 1 megawatt (1 MW).

g. Commission: the Rhode Island Public Utilities Commission.

h. Company: The Narragansett Electric Company d/b/a National Grid.

i. Customer: a customer receiving retail delivery service pursuant to one of the Company's non-residential retail delivery service rate schedules and listed as the customer-of-record on the billing account associated with the service location.

j. DG Project: a distinct installation of an electrical generation facility that is located in the Company's service territory, is connected to the Company's electric distribution system, and has a nameplate capacity no greater than five megawatts (5 MW) using eligible renewable energy resources as defined in 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.

k. ISO-New England, Inc. ("ISO-NE"): the Independent System Operators of New England, Inc., established in accordance with the NEPOOL Agreement and applicable Federal Energy Regulatory Commission approvals, which is responsible for managing the bulk power generation and transmission systems in New England.

l. Large DG Project: a DG Project with a nameplate capacity that exceeds the size of a Small DG Project in a given year, but is no greater than five megawatts (5 MW) nameplate capacity.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

m. Large-Scale Solar Project: a solar DG Project with a nameplate capacity of one megawatt (1 MW) or greater and up to and including five megawatts (5 MW).

n. Medium-Scale Solar Project: a solar DG Project with a nameplate capacity greater than 25 kilowatts (25 kW) and up to and including 250 kilowatts (250 kW).

o. Nameplate Capacity: the maximum rated output or gross output of a DG Project. For a solar DG Project, it is the total rated power output of all the DG Project's panels, measured in direct current.

p. Office: the Rhode Island Office of Energy Resources.

q. On-Site Use: the amount of energy used at a Customer's service location during a billing period that may be delivered by the Company, or supplied by the DG Project, or both.

r. Output Certification: certification provided by an independent engineer (licensed Professional Engineer) stating that construction of both the DG Project and the interconnection facilities is complete in all material respects, that the metering has been installed and tested, that the Nameplate Capacity is as on the Certificate of Eligibility, and that the DG Project is capable of producing at least 90% of the maximum hourly output specified on the Certificate of Eligibility.

s. Performance-Based Incentive: either a standard or competitively bid price per kilowatt-hour ("kWh") that is applicable to the output of a DG Project when the Applicant has been awarded a Certificate of Eligibility, pursuant to the Rules.

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

u. Renewable Energy Classes: categories for different renewable energy technologies using eligible renewable energy resources as defined in 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 specified in § 39-26-2(6).

v. Renewable Energy Certificate ("REC"): an electronic record produced by the New England Generation Information System ("NE-GIS") that identifies the relevant generation attributes of each megawatt-hour accounted for in the NE-GIS.

w. Small-Scale Solar Project: a solar DG Project with a nameplate capacity of up to and including 25 kilowatts (25 kW).

x. Small DG Project: either: (1) a Small-Scale Solar Project; (2) a Medium-Scale Solar Project; (3) a wind DG Project with a nameplate capacity of at least fifty kilowatts (50 kW) up to one and one-half megawatts (1.5 MW); or (4) a DG Project using renewable energy resources other than solar and wind, with a nameplate capacity to be determined by the Board, but no greater than one megawatt (1 MW).

y. Solicitation and Enrollment Process Rules: the rules governing the solicitation, enrollment, and award processes for the RE Growth Program for Non-Residential Customers, established pursuant to Chapter 26.6, and approved by the Commission.

z. Station Service: energy used to operate auxiliary equipment and other load that is directly related to the production of energy by a DG Project.

3. **Performance Guarantee Deposit**

a. No later than five (5) business days after a project is offered a Certificate of Eligibility, the Applicant shall submit by wire transfer a Performance Guarantee Deposit ("Deposit") as identified on the Certificate of Eligibility. Upon confirmation of the receipt of the Deposit, the Company shall award the Certificate of Eligibility. Each Deposit shall be no less than $500.00 and no greater than $75,000.00. The Deposit shall be calculated as $15.00 for Small DG Projects or $25.00 for Large DG Projects, multiplied by the estimated RECs to be generated during the DG Project's first year of operation.

b. If the Company does not receive a Deposit by the date required, the Company may withdraw the Certificate of Eligibility offer and not proceed further with the Applicant in that enrollment.

c. The Deposit shall be refunded to the Applicant during the first year of the DG Project's operation, paid quarterly. In the event that the Applicant terminates the DG Project prior to operation, the Deposit will be forfeited.

d. After receiving the Certificate of Eligibility, the Applicant must provide the Output Certification within: (1) 48 months for Small DG Projects using hydropower; (2) 36 months for anaerobic digestion; or (3) 24 months for all other DG Projects. If the Output Certification is not received within the specified timeframe, the Certificate of Eligibility will be voided and the Deposit will be forfeited.

e. Once a DG Project has provided the Output Certification to National Grid, the project then has 90 days to meet all other requirements specified in Section 8(a) to receive payment pursuant to the Tariff.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

f. An Applicant may elect, for any reason, to extend the DG Project deadline for providing the Output Certification by an additional six (6) months with no additional Deposit. After such initial six-month extension, the Applicant may elect, for any reason, to extend Output Certification deadline for an additional six-month period by posting an additional Deposit amount equal to one-half of the original Deposit amount. An Applicant shall not extend the deadline to provide the Output Certification by more than one (1) year in total. Prior to the expiration of the timeframe applicable to the Applicant's DG Project, as specified herein Section 3(d) or as extended as provided for by Section 3(f), the Applicant must notify the Company of its election to extend the DG Project deadline.

g. If the Applicant is unable to provide the Output Certification within the timeframe specified in Section 3(d), or as extended pursuant to Section 3(f), because of non-completion of the necessary system modifications on the Company's side of the meter or any other interconnection delays that are beyond the reasonable control of the Applicant, the deadline for providing the Output Certification will be extended until such time as the DG Project has received approval from the Company to interconnect to the Company's distribution system and begin production, with no additional deposit required.

h. If an act of God occurs within the timeframe allowed for providing the Output Certification, and as a direct result of the act of God, the DG Project is incapable of providing the Output Certification within the timeframe prescribed in this Tariff, the DG Project shall be terminated and the Deposit shall be refunded immediately.

i. Small-Scale Solar Projects and Medium-Scale Solar Projects are not required to submit a Performance Guarantee Deposit or provide an Output Certification. In order to receive Performance-Based Incentive payments under this Tariff, such projects will have 24 months after being awarded a Certificate of Eligibility to achieve operation at expected availability and capacity and meet all other requirements under this Tariff.

4. **Interconnection**

a. The interconnection of the DG Project with the Company's distribution system and any system modifications required by the Company shall be in accordance with the Standards for Connecting Distributed Generation and coordinated or delegated by the Applicant.

b. Except for Small-Scale Solar Projects and Medium-Scale Solar Projects, all Applicants for DG Projects awarded a Certificate of Eligibility are required to submit quarterly reports to the Company and the Office reporting on the progress of construction. Failure to submit these reports may result in the loss of the Applicant's Certificate of Eligibility.

5. **Project Segmentation**

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

There is a prohibition on project segmentation within the RE Growth Program. If the Company determines that an Applicant has segmented a DG Project into two or more smaller-sized Projects for the purpose of qualifying them for smaller renewable energy class, the Company will award the Applicant a Certificate of Eligibility for only one of the DG Projects. In making its determination, the Company will look for one of the following exceptions:

i. The DG Projects use different renewable energy resources; or

ii. The DG Projects use the same renewable energy resource, but they are: (1) electrically segregated; (2) separately metered; and (3) can demonstrate that 24 months have elapsed between the commencement of operation for one DG Project and the commencement of construction of any additional DG Project.

iii. DG Projects installed on contiguous parcels will not be considered segmented if they serve different Non-Residential Customers and both Customers receive bill credits under Option 2 as defined in Section 8.c.

If the Company determines that a DG Project is ineligible to enroll in the RE Growth Program due to project segmentation, the DG Project may be eligible for compensation pursuant to the Net Metering Provision or through other energy market participation. If an Applicant is awarded a Certificate of Eligibility for a DG Project and is receiving Performance-Based Incentive Payments pursuant to this Tariff it will not receive compensation pursuant to the Net Metering Provision for the same DG Project during the term specified in the applicable Tariff supplement.

6. **Metering**

a. A Company-owned interval meter must be installed on all DG Projects that are enrolled in the RE Growth Program for the purpose of measuring and reporting the output of the DG Project. In the event that there is an existing service location with an existing meter, the meter for the DG Project shall be wired in parallel with, and be adjacent to, the existing service meter. In the event an existing service meter is present, the existing service meter will be exchanged for an interval meter by the Company at the Applicant's expense.

b. For Medium-Scale Solar Projects, Commercial-Scale Solar Projects, Large-Scale Solar Projects, and DG Projects of other eligible technologies, the Applicant is responsible for the cost of a revenue-quality interval meter and associated metering equipment, including required remote communication for measuring and reporting the output of the DG Project as well as any existing service meter. An Applicant may elect to supply the meter and associated equipment provided that it conforms to the Company's metering standards and the Rhode Island Division of Public Utilities and Carrier's Rules for Prescribing Standards for Electric Utilities, as may be amended from time to time. At the request of the Applicant, the Company will provide the required interval meter and associated equipment, subject to the

Company having such equipment available and the Applicant reimbursing the Company for its cost.

c. The Company must be provided with adequate access to read the meter(s), and to install, repair, maintain and replace the meter(s), if applicable.

7. **Energy, Capacity, Renewable Energy Certificates and Other Environmental Attributes**

a. Prior to receiving compensation pursuant to Section 8 of this Tariff, an Applicant, at its own cost, must obtain Commission certification of a DG Project as an Eligible Renewable Energy Resource pursuant to the Commission's Rules and Regulations Governing the Implementation of a Renewable Energy Standard. The Company shall assume the obligation to qualify the DG Project under the renewable portfolio standard or similar law and/or regulation of New York, Massachusetts, and/or one or more New England states and/or any federal renewable energy standard.

b. The Applicant for a DG Project shall provide all necessary information to, and cooperate with, the Company to enable the Company to obtain the appropriate asset identification for reporting generation to ISO-NE and the NEPOOL Generation Information System for the creation of RECs, designate the Company, or another party as directed by the Company, as the Applicant's Responsible Party under the NEPOOL-GIS rules, and direct all RECs from the DG Project to the Company's appropriate NEPOOL-GIS account. If requested by the Company, Applicant will provide approvals or assignments, as necessary, to facilitate Applicants participation in asset aggregation or other model of asset registration and reporting.

For the term specified in the applicable Tariff supplement, the Company shall have the irrevocable rights and title to the following products produced by the DG Project: (1) RECs; (2) energy; and (3) any other environmental attributes or market products associated with the sale of energy or energy services produced by the DG Project, provided, however, that it shall be the Company's choice to acquire the capacity of the DG Project at any time after it is awarded a Certificate of Eligibility by the Commission or the Company pursuant to the Rules. Environmental attributes shall include any and all generation attributes or energy services established by regional, state, federal, or international law, rule, regulation or competitive market or business method that are attributable, now or in the future, to the output produced by the DG Project during the term of service specified on the applicable Tariff supplement.

8. **Performance-Based Incentive Payment**

a. Eligibility

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

Upon receipt of a Certificate of Eligibility, the Applicant is entitled to the Performance-Based Incentive Payment for the term specified in the applicable Tariff supplement, provided that the Applicant has complied with all other requirements of this Tariff and the Solicitation and Enrollment Process Rules.

As a condition for receiving monthly payments pursuant to Section 9c, the Applicant must provide confirmation of the following: 1) the Company's written authority to interconnect to its electric distribution system and Applicant's payment of all amounts due; 2) Commission certification of the DG Project as an Eligible Renewable Energy Resource; 3) registration of the DG Project with the ISO-NE and NEPOOL GIS; and 4) except for small-scale and medium-scale solar, the Output Certification. If an Applicant or Customer is no longer in good standing with regard to payment plans or agreements, if applicable, and other obligations to the Company (including but not limited to meeting all obligations under an interconnection service agreement), the Company may withhold payments under this Tariff. In addition, the Customer must remain in good standing with regard to the electric service account receiving Bill Credits pursuant to this tariff.

b. Performance-Based Incentive

The Performance-Based Incentive will be a fixed per-kWh price for the term specified in the applicable Tariff supplement.

The Performance-Based Incentive for Small-Scale Solar and Medium-Scale Solar shall be a standard Performance-Based Incentive that is recommended by the Board and approved by the Commission. The Performance-Based Incentive for other DG Projects shall be determined through competitive bidding.

Zonal Incentive: In addition to the Performance-Based Incentive, the Company may propose, and the Commission may approve, a zonal incentive, which is in addition to the Performance-Based Incentive for DG Projects that are: 1) located in designated geographic areas; or 2) comply with other specified conditions. Any Zonal Incentive shall be reflected in the applicable Tariff supplement.

c. Performance Based Incentive Payment

The Performance-Based Incentive Payment will be the fixed per-kWh Performance-Based Incentive, plus any Zonal Incentive where applicable, applied to the measured kilowatt-hours (kWh) produced by the DG Project, net of any Station Service.

Before a DG Project begins to operate, an Applicant must notify the Company of the manner by which it will be compensated for its output under one of the two options below. The Applicant may select Option 2 only if the DG Project can be configured to serve on-site load and the DG Project is reasonably designed and sized to produce electricity at an annual level equal to or less than 1) the Customer's On-Site Use as measured over the previous three (3) years at the electric service account

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

located at the Customer's service location; 2) the annualized On-Site Use over the period of service to the Customer's service location if such service has been provided for less than three years; or 3) a reasonable estimate of annual On-Site Use if the Project is located at a new service location. The Applicant may change the selection only one time after the DG Project begins to operate provided that the Applicant gives the Company no less than 60 days' notice to implement the change. Additional changes to the method of compensation may be allowed at the discretion of the Company. The options are:

1. Option 1: Direct payment of the entire Performance-Based Incentive Payment in the form of a check or such other payment method that is mutually agreed upon by the Company and the Applicant; or

2. Option 2: A combination of direct payment and a Customer bill credit, in which the value of the bill credit will be based upon the On-Site Use, up to, but not exceeding, the metered generation of the DG Project.

If a DG Project selects Option 2, the Performance-Based Incentive Payment shall be provided as follows:

The Customer's bill will be based upon the On-Site Use, the retail delivery service charges and the Standard Offer Service or Non-Regulated Power Producer charges in effect during the billing period and which apply to the Customer's retail delivery service rate class. The Company shall apply a Bill Credit, as calculated below, to offset the Customer's bill. The Bill Credit will appear as a separate line item on the Customer's bill.

BC = OSU (kWh) x (DCHG + SOS)

Where:

BC = Bill Credit

OSU (kWh) = On-Site Use kWh at the lesser of 1) the On-Site Use measured in kWh per month, or 2) the DG Project output measured in kWh per month.

DCHG = the sum of all retail delivery service per kWh charges applicable to the Customer's retail delivery service rate class per RIPUC No. 2095, Summary of Retail Delivery Rates, as may be amended from time to time.

SOS = the Standard Offer Service charge applicable to the Customer's retail delivery service rate class per RIPUC No. 2096, Summary of Standard Offer Service Rates, as may be amended from time to time.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

The remaining amount of the Performance-Based Incentive Payment will be paid in the form a check (or another agreed-upon means) to the recipient as identified on the Application. The Customer will be responsible for paying any balance due on the electric bill in accordance with the Terms and Conditions for Distribution Service.

If the Bill Credit in a given month exceeds the Performance-Based Incentive Payment, the Customer shall receive the full amount of the Bill Credit, which will not exceed the total of the per kWh delivery service charges and applicable Standard Offer Service charges, excluding the customer charge and any applicable taxes. There will be no additional amounts related to the calculation of the Performance-Based Incentive Payment charged or credited to the Customer or the recipient identified on the Application.

Only one billing account will be eligible to receive Bill Credits from each DG Project pursuant to this provision.

9. Access Fee

An Applicant choosing Option 1 as described in Section 8.c.1 shall be subject to an Access Fee for the use of the Company's distribution system by the DG Project for the purpose of exporting electricity generated by the DG Project into the electric distribution system. The Access Fee shall be a fixed per-kilowatt charge assessed monthly and shall be applied to a fixed capacity value determined as the Nameplate Capacity of the DG Project adjusted by a capacity factor applicable to the DG Project's technology. The customer of record of the account associated with the DG Project must execute an Access Service Agreement and be subject to its terms and conditions. The Access Fee does not alter the Applicant's obligations for the interconnection of the DG Project to the Company's electric distribution system as provided in Section 4.a above.

The Access Fee per-kilowatt shall be $7.25 for DG Projects interconnected to the Company's secondary voltage distribution system and $5.00 for DG Projects interconnected to the Company's primary voltage distribution system. The Access Fee is assessed to the retail delivery service account associated with the DG Project regardless of the method by which the Applicant receives compensation pursuant to Section 8.c.

~~9.~~10. Other Company Tariff Requirements

a. The Company will provide the Customer with retail delivery service under the applicable retail delivery service tariff and the Company's Terms and Conditions for Distribution Service.

b. The Applicant is required to comply with Company's Standards for Connecting Distributed Generation.

c. To be eligible to receive Renewable Net Metering Credits or excess Renewable Net Metering Credits pursuant to the Company's Net Metering Provision following the termination of the Customer's participation in the RE Growth Program, a DG Project and a Customer receiving credits from such a facility must comply with the applicable provisions of the Company's Net Metering Provision.

d. The Company's recovery of costs incurred to implement and administer the RE Growth Program is pursuant to the Renewable Energy Growth Program Cost Recovery Provision.

~~10.~~11. **Dispute Resolution**

If any dispute arises between the Company and either the Applicant or the Customer, the dispute shall be brought before the Commission for resolution. Such disputes may include but are not limited to those concerning the Rules, terms, conditions, rights, responsibilities, the termination of the Tariff or Tariff supplement, or the performance of the Applicant, the Customer, or the Company.

~~11.~~12. **Termination Provisions**

The Applicant and the Customer shall comply with the provision of this Tariff through the end of the term specified in the applicable Tariff supplement. The Applicant and the Customer may not terminate their obligations under this Tariff unless and until the Company consents to such termination. The Company will not unreasonably delay or withhold its consent to an Applicant's request to terminate if the Applicant cannot fulfill the obligations because of an event or circumstance that is beyond the Applicant's reasonable control and for which the Applicant could not prevent or provide against by using commercially reasonable efforts.

Only the DG Project described on the Certificate of Eligibility is eligible to participate under this Tariff. In no event shall an Applicant expand a DG Project's nameplate capacity beyond what is allowed by the Certificate of Eligibility. If a DG Project exceeds the nameplate capacity allowed by the Certificate of Eligibility, or the Company determines that a Customer or Applicant has violated the terms and conditions of this Tariff, the Company may, after notifying the Customer or Applicant in writing of such non-compliance and providing the Customer or Applicant a reasonable period to remedy such non-compliance and the violation persists, request the Commission to review the non-compliance and determine appropriate action, which may include requiring the Customer or Applicant to comply with the applicable provision being violated or revoking the Customer's or Applicant's Certificate of Eligibility.

THE NARRAGANSETT ELECTRIC COMPANY
RENEWABLE ENERGY GROWTH PROGRAM FOR NON-RESIDENTIAL CUSTOMERS

~~12.~~13. **Statutory Authority**

This Tariff is filed in compliance with R.I. Gen. Laws. § 39-26.6-10. All revisions to the Tariff will be filed annually by November 15. Tariff supplements will be filed annually and following each scheduled RE Growth Program enrollment, as necessary. This Tariff and its supplements are subject to review, approval, and the exclusive jurisdiction of the Commission.

Effective Date: April 1, 2016~~5~~

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Program Year: April 1, 2015 through March 31, 2016

Performance-Based Incentives and associated Performance-Based Incentive Payment shall remain in effect during the term of service noted below in accordance with R.I.G.L. § 39-26.6-20.

Term of Service represents the period of time during which the DG Project earns Performance-Based Incentive Payments. The billing month during which Performance-Based Incentive Payments begin will be specific to each individual DG Facility, and the Term of Service for a particular DG Facility will commence upon the first month of operation.

Renewable Energy Class	System Size	Ceiling Price/Standard Performance –Based Incentive (per kWh)	Term of Service
Small-Scale Solar I, Host Owned	1 to 10 kW	41.35¢	15 years
Small-Scale Solar I, Host Owned	1 to 10 kW	37.75¢	20 years
Small-Scale Solar I Third-Party Owned	1 to 10 kW	32.95¢	20 years
Small-Scale Solar II	11 to 25 kW	29.80¢	20 years
Medium-Scale Solar	26 to 250 kW	24.40¢	20 years

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Program Year: April 1, 2015 through March 31, 2016

Renewable Energy Class	Ceiling Price	Enrollment Date	Applicant Name	DG Facility Address	Nameplate Capacity (MW)	Performance Incentive (per kWh)	Term of Service
Commercial-Scale Solar	20.95¢						20 years
Large-Scale Solar	16.70¢						20 years
Wind I (1.5MW to 2.99MW) with Investment Tax Credit	18.40¢						20 years
Wind I (1.5MW to 2.99MW) with Production Tax Credit	19.85¢						20 years
Wind I (1.5MW to 2.99MW) with No Federal Tax Incentives	22.75¢						20 years
Wind II (3.0MW to 5.0MW) with Investment Tax Credit	18.20¢						20 years
Wind II (3.0MW to 5.0MW) with Production Tax Credit	19.45¢						20 years
Wind II (3.0MW to 5.0MW) with No Federal Tax Incentives	22.35¢						20 years
Anaerobic Digestion (150kW to 1,000kW) with Production Tax Credit	20.20¢						20 years

The Narragansett Electric Company
Renewable Energy Growth Program for Non-Residential Customers
Tariff Supplement

Anaerobic Digestion (150kW to 1,000kW) with No Federal Tax Incentives	20.60¢						20 years
Small-Scale Hydropower I (10kW to 250kW) with Production Tax Credit	19.80¢						20 years
Small-Scale Hydropower I (10kW to 250kW) with No Federal Tax Incentives	21.35¢						20 years
Small-Scale Hydropower II (251kW to 1,000kW) with Production Tax Credit	18.55¢						20 years
Small-Scale Hydropower II (251kW to 1,000kW) with No Federal Tax Incentives	20.10¢						20 years

reflect the actual relative cost to serve each customer, both those with and without DG. The key components of the Company's rate design proposals include the following:

- The Company's proposed rates will reduce the amount of its revenue requirement recovered through variable (per kilowatt-hour) charges and increase the amount recovered through customer and/or demand (per kilowatt) charges, yet will create a distinct incentive for customers to conserve their use of energy.

- The Company will implement the proposed rates for each class using currently installed metering for each class.

- The rate structure for Residential Rate A-16 and Small Commercial and Industrial (C&I) Rate C-06 includes tiered customer charges.

- The Company designed the proposed rates so that no individual residential or small C&I customer within Rates A-16 and C-06 will experience a bill change of more than five percent on a total bill basis.

- The Company proposes to consolidate Large Demand Rate G-32 and Optional Large Demand Rate G-62 to simplify and streamline the Company's tariff offerings for its larger C&I customers.

- The Company is proposing a charge applicable to stand-alone DG facilities that will be based upon the size of the facility. In addition, the Company proposes that DG facilities no longer be allowed to net their station service usage against the amount of electricity generated by the DG facility, unless they are specifically enrolling in net metering.

- The Company is not proposing changes to the Low Income Rate A-60, but will consider the appropriate design of the rates for this class in the Company's next electric distribution rate case.

- No changes are proposed for the following rate classes:
  - Rate X-01, Electric Propulsion;
  - Rate M-01, Station Power; and
  - Outdoor Lighting Rates, S-05, S-06, S-10, S-14.

To comply with the RE Growth Program Act, the Company is proposing a re-design of distribution rates that is revenue-neutral (i.e., designed to produce the same level of revenue, no more or no less, than the revenue which current distribution rates were designed to generate) using the revenue requirement and billing units that were approved in the Company's last distribution rate case (Docket No. 4323). The Company is also proposing to use the individual rate class revenue requirements that were determined as part of the allocated cost of service study in Docket No. 4323, including the final revenue allocation. As provided in the RE Growth

Program Act, the proposed rates would take effect for usage on or after April 1, 2016.[4] However, the Company will be required to modify its billing system to implement any new rates approved by the PUC in this docket and is permitted to seek an extension of the April 1, 2016 effective date of new rates, if necessary, to make the billing system changes required to implement a new rate structure.

The Company's filing consists of the joint pre-filed direct testimony, schedules, and workpapers of Peter T. Zschokke and Jeanne A. Lloyd. In their joint testimony, Mr. Zschokke and Ms. Lloyd present the Company's proposed distribution rate re-design and discuss the key factors the Company considered in developing its proposal. They also discuss the role of the distribution utility in a distributed energy world and describe the impact of the future distribution utility on rate design. Finally, Mr. Zschokke and Ms. Lloyd describe the allocated cost of service study used to design the proposed rates, present the typical bills and individual customer impacts of the proposed rate changes, and explain the proposed tariff changes and tariff provisions necessary to implement the Company's rate re-design. A clean version of the amended retail delivery service tariffs and the proposed tariff provisions is attached as Schedule NG-15. The redlined version of the proposed retail delivery service tariffs, identifying the changes to the tariffs currently in effect, and the proposed tariff provisions, is contained in this filing as Schedule NG-16.

The Company's filing is another step in the ongoing evolution of the electric industry towards a sustainable future while ensuring the costs to run a safe and reliable electric distribution system that is relied upon by all customers, including those with and without DG, are recovered from all customers in a fair and equitable manner.

Thank you for your attention to this transmittal. If you have any questions concerning this filing, please contact me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

Celia B. O'Brien

Enclosures

cc: Docket 4568 Service List
Steve Scialabba, Division
Richard Hahn, Division
Leo Wold, Esq.

[4] The RE Growth Program Act was amended in 2015 to extend the date by which the PUC must issue an order from December 1, 2015 to March 1, 2016 and the effective date of new rates from January 1, 2016 to April 1, 2016. See 2015 R.I. Pub. Laws c. 59, s. 1.

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

Paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

____________________________________ July 31, 2015

Joanne M. Scanlon Date

Docket No. 4568 National Grid's Rate Design Pursuant to R.I. Gen. Laws Sec 39-26.6-24
Service List updated 7/16/15

Parties' Name/Address	E-mail	Phone
Celia B. O'Brien, Esq. National Grid 280 Melrose Street Providence, RI 02907	Celia.obrien@nationalgrid.com; Joanne.scanlon@nationalgrid.com; Theresa.burns@nationalgrid.com; Jeanne.lloyd@nationalgrid.com; Ian.springsteel@nationalgrid.com; Peter.zschokke@nationalgrid.com;	781-907-2153
Division of Public Utilities and Carriers Leo Wold, Esq. Karen Lyons, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Lwold@riag.ri.gov; Klyons@riag.ri.gov; Jmunoz@riag.ri.gov; Dmacrae@riag.ri.gov; Steve.scialabba@dpuc.ri.gov; Al.contente@dpuc.ri.gov;	401-222-2424 Ext. 2218
Richard Hahn Lacapra Associates 1 Washington Mall, 9th floor Boston, MA 02108	rhahn@lacapra.com; apereira@lacapra.com;	
Office of Energy Resources Daniel W. Majcher, Esq. Dept. of Administration Division of Legal Services One Capitol Hill, 4th Floor Providence, RI 02908	Daniel.majcher@doa.ri.gov;	401-222-8880
Marion Gold, Commissioner Office of Energy Resources One Capitol Hill, 4th Floor Providence, RI 02908	Marion.gold@energy.ri.gov; Nicholas.Ucci@energy.ri.gov; Danny.musher@energy.ri.gov; Christopher.kearns@energy.ri.gov;	401-574-9113
Conservation Law Foundation Jerry Elmer, Esq. Conservation Law Foundation 55 Dorrance Street Providence, RI 02903	jelmer@clf.org;	401-351-1102 Ext. 2012
File an original & 9 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.wilsonfrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107