KEEGAN WERLIN LLP

ATTORNEYS AT LAW
265 FRANKLIN STREET
BOSTON, MASSACHUSETTS 02110-3113
(617) 951-1400

TELECOPIERS:
(617) 951-1354
(617) 951-0586

September 20, 2013

Mark D. Marini, Secretary
Department of Public Utilities
One South Station, 5th Floor
Boston, MA 02110

Re: NSTAR Electric Company, D.P.U. 13-148
Section 83A Long-term Contracts for Renewable Energy

Dear Secretary Marini:

Enclosed for filing on behalf of NSTAR Electric Company ("NSTAR Electric") in the above-captioned proceeding is a Petition for Approval of six Power Purchase Agreements ("PPAs") executed by NSTAR Electric covering the long-term procurement of renewable energy and Renewable Energy Certificates ("RECs") from six individual wind projects. The six projects were jointly selected for long-term contracts by NSTAR Electric, Western Massachusetts Electric Company ("WMECO"), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid") and Fitchburg Gas and Electric Light Company d/b/a Unitil ("Fitchburg") (collectively the "Distribution Companies") from the competitive bids obtained pursuant to a joint solicitation conducted by the Distribution Companies. The filing is made in accordance with the requirements of Green Communities Act, Section 83A (St. 2008, c. 169, § 83A) and follows the joint and collaborative Request for Proposals Process approved by the Department of Public Utilities (the "Department") in D.P.U. 13-57.

This proceeding is one of four related dockets at the Department (D.P.U. 13-146 through 13-149) to review the PPAs individually executed by each of the Distribution Companies for the six projects. The Distribution Companies conducted this competitive solicitation jointly, including: the joint issuance of a single RFP; joint evaluation and scoring of the bids received; joint selection of the winning bids; and the joint negotiation of final contracts. Due to common issues of law and fact in the conduct of this competitive solicitation, the identical Joint Testimony and supporting Exhibits are being filed simultaneously by the Distribution Companies in each of the four dockets. Accordingly, there are six executed PPAs (one for each of six projects), provided by each of the Distribution Companies, for a total of twenty four PPAs for Department review and approval pursuant to Section 83A.

In support of each Petition, the filing herein includes the prefiled Joint Testimony and supporting Exhibits of Jeffery S. Waltman, Corinne Abrams and Robert S. Furino demonstrating that: (1) the Distribution Companies' execution of the long-term renewable power contracts satisfies the requirements of Section 83A of the Green Communities Act; (2) the Distribution Companies have followed the provisions of the Request for Proposal Process approved by the Department in D.P.U. 13-57; and (3) that the proposed Contracts compare favorably on price and non-price factors to the range of renewable energy resources available in the marketplace today and thus are low-cost, cost-effective contracts.

Also enclosed is the prefiled Direct Testimony of Mr. Richard Chin in support of the recovery of the costs of the PPAs through the pricing provisions of NSTAR Electric's proposed amended Long-Term Renewable Contract Adjustment Tariff, M.D.P.U. No. 164B. A redline copy of the proposed LTRCA Tariff, showing all changes from the current Tariff in effect, is also included as an Exhibit.

Please note that each of the Exhibits supporting the joint testimony, other than Exhibit JU-7, contain confidential and proprietary information, for which the Distribution Companies are seeking protective treatment. Accordingly, this public version of the filing contains redacted copies of the confidential Exhibits. Original, unredacted versions of the Confidential Exhibits are being submitted to the Department under separate cover, under seal.

In addition, the Distribution Companies have been requested by First Wind, developer of the Oakfield Wind Project, to include in this filing a proposed procedural schedule to review the Distribution Companies' respective PPAs with Evergreen Wind Power II, LLC. The proposed procedural schedule is provided as Attachment A to this filing letter. The developer requests Department approval by December 6, 2013 in order for the Oakfield Wind Project to proceed to construction as soon as possible after that date. The Distribution Companies support First Wind's request, and further support Department review of the remaining PPAs in an expeditious manner in order to allow the benefits of these agreements to accrue to the Distribution Companies' customers as soon as possible.

Also enclosed is a check for $100 in satisfaction of the filing fee. Thank you for your attention to this matter.

Very truly yours,

Danielle C. Winter

Danielle C. Winter
Donald W. Boecke

Enclosures

cc: Joan Foster Evans, Assistant General Counsel
Jesse Reyes, Chief, Office of Ratepayer Advocacy, Office of Attorney General
Jamie Tosches, Assistant Attorney General
Anna Blumkin, Department of Energy Resources
Elizabeth Mahoney, Department of Energy Resources

ATTACHMENT A

Proposed Procedural Schedule – Oakfield Contracts

September 20 – Utilities submit petitions for contract approval to the DPU.

September 24/25 – DPU issues Order of Notice to Utilities for publication.

September 24 – Discovery period begins for DPU Staff, AG

September 27 – Utilities publish Notice in designated newspapers

October 11 – (1) Public Hearing and Procedural Conference in Boston; (2) Deadline for Petitions to Intervene; (3) Deadline for written comments

October 18 – Deadline for Intervenor discovery

October 30 – All discovery responses filed

November 5 - 6 – Evidentiary Hearings

November 13 – Simultaneous Initial Briefs due

November 18 – Simultaneous Reply Briefs due

December 6 – DPU Issues Final Decisions on Utility – Evergreen contracts

INDEX TO FILING

- Petition

- Joint Testimony of Waltman/Abrams/Furino

- Exhibit JU-1 [CONFIDENTIAL], Tabs A-D, four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to the Iberdrola Renewables Wild Meadows wind project;

- Exhibit JU-2 [CONFIDENTIAL], Tabs A-D, four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Iberdrola Renewables Fletcher Mountain wind project;

- Exhibit JU-3 [CONFIDENTIAL], Tabs A-D, four individual 15-year PPAs executed by NSTAR Electric, WMECO,National Grid and Fitchburg applicable to First Wind Oakfield Wind;

- Exhibit JU-4 [CONFIDENTIAL], Tabs A-D, four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to First Wind Bingham Wind;

- Exhibit JU-5 [CONFIDENTIAL], Tabs A-D, four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Exergy Development Passamaquoddy Wind;

- Exhibit JU-6 [CONFIDENTIAL], Tabs A-D, four individual 20-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Exergy Development Peskotmuhkati Wind.

- Exhibit JU-7(a) is a copy of the Request for Proposals ("RFP") approved by the Department in D.P.U. 13-57, and includes Exhibit JU-7(b) the Draft PPA (with subsequent revision (Exhibit JU-7(c)), which was used by the Distribution Companies to jointly solicit and procure the contracts.

- Exhibit JU-8 [CONFIDENTIAL] summary of overall bid scoring results prior to initial selection of the Short List.

- Exhibit JU-9 [CONFIDENTIAL] summary of the non-price scores awarded for non-price factors.

- Exhibit JU-10 [CONFIDENTIAL] displays the fifteen bids selected from the overall scoring results of Exhibit JU-8 for inclusion on the Short List and provided an opportunity to refresh bid prices.

- Exhibit JU-11 [CONFIDENTIAL] is the refreshed ranking and selection of the Final Short List subsequent to the opportunity afforded to short listed bidders to refresh prices. The projects on the Final Short List selected for contract negotiation are highlighted on Exhibit JU -11.

- Exhibit JU-12 [CONFIDENTIAL] is the common market price forecast prepared by the Distribution Companies' consultant, ESAI.

- Testimony of Richard D. Chin (cost recovery)

- Exhibit NSTAR-RDC-1 [CONFIDENTIAL]

- Exhibit NSTAR-RDC-2

- Exhibit NSTAR-RDC-3

- Exhibit NSTAR-RDC-4

- Exhibit NSTAR-RDC-5

WORKPAPER SUPPORT

- Tab A - List of entities sent the RFP;

- Tab B - Firms providing notice of intent to bid;

- Tab C - [CONFIDENTIAL – CD-ROM ONLY] complete bid package for bids received;

- Tab D - [CONFIDENTIAL – CD-ROM ONLY] Bid evaluation and scoring spreadsheet model, in Excel format (Bid Analysis June27.xlsx), prior to selection of short list;

- Tab E - [CONFIDENTIAL – CD-ROM ONLY] Bid evaluation and scoring spreadsheet model, in Excel format (Bid Analysis July17.xlsx), with refreshed prices from short list bidders;

- Tab F - [CONFIDENTIAL] redline of sample PPA from each developer against Draft RFP;

- Tab G - [CONFIDENTIAL] redline of sample PPA from each Distribution Company for a single project against Draft RFP.

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company, For Approval of Proposed Long-term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	)	D.P.U. 13-148

**PETITION OF NSTAR ELECTRIC COMPANY
FOR APPROVAL OF SIX POWER PURCHASE AGREEMENTS
PURSUANT TO ST. 2008, C. 169, §83A**

Now comes NSTAR Electric Company ("NSTAR Electric" or the "Company") and requests that the Department of Public Utilities (the "Department") approve, pursuant to Section 83A of Chapter 169 of the Acts of 2008 ("Section 83A") and the Department's regulations at 220 C.M.R. 21.00 et seq., the enclosed six long-term contracts for renewable energy ("PPAs") executed in culmination of a joint competitive solicitation undertaken pursuant to Department approval conferred by D.P.U. 13-57. As described in more detail below, the Company has entered into the PPAs to acquire its pro rata share of total renewable energy output and Renewable Energy Certificates ("RECs") from the following six wind energy projects:

Table 1

PROJECT NAME	PRINCIPAL DEVELOPER	CONTRACT COUNTERPARTY	OUTPUT (MW)	CONTRACT TERM (Yrs.)
Wild Meadows	Iberdrola Renewables	Iberdrola Renewables, LLC	75.9	15
Fletcher Mountain	Iberdrola Renewables	Iberdrola Renewables, LLC	97.1	15

Oakfield Wind	First Wind	Evergreen Wind Power II, LLC	147.6	15
Bingham Wind	First Wind	Blue Sky West, LLC	186	15
Passamaquoddy Wind	Exergy Development Group	Passamaquoddy Wind, LLC	38.2	15
Peskotmuhkati Wind	Exergy Development Group	Peskotmuhkati Wind, LLC	20	20

In support of the Company's request, NSTAR Electric states the following:

1. NSTAR Electric is a Massachusetts electric company, pursuant to G.L. c. 164, § 1, with a principal place of business in Boston, Massachusetts.

2. NSTAR Electric participated jointly with the other investor-owned electric distribution companies in Massachusetts (collectively the "Distribution Companies") in conducting this competitive solicitation pursuant to Section 83A, including: the joint issuance of a single RFP; joint evaluation and scoring of the bids received; joint selection of the winning bids; and the joint negotiation of final PPAs. Accordingly, there are six executed PPAs (one for each of six projects), provided by each of the four Distribution Companies, for a total of twenty four PPAs for Department review and approval pursuant to Section 83A.

3. The filing set forth herein includes: (1) the pre-filed joint testimony (the "Joint Testimony") and accompanying exhibits of: Jeffery S. Waltman, Manager, Planning and Power Supply for Massachusetts regulated operating companies of Northeast Utilities which includes NSTAR Electric; Corrine M. Abrams, Manager of Environmental Transactions, Energy Procurement with National Grid; and Robert S. Furino, Director of Energy Contracts with Unitil Services Corp.

regarding the proposed PPAs; and (2) the pre-filed testimony and accompanying exhibits of Richard D. Chin, Manager of Rates for Northeast Utilities, describing the Company's proposed cost recovery and rate-design proposal relating to the PPAs. In particular, Mr. Chin's testimony includes a proposed amendment to NSTAR Electric's Long-Term Renewable Contract Adjustment tariff, M.D.P.U. No. 164B, to recover the Company's costs associated with contracts procured in accordance with Section 83A.

4. Section 83A and the Department's regulations at 220 C.M.R. § 21.00 <u>et</u> <u>seq.</u> require that long-term contracts entered into by a distribution company must be made with renewable energy generation sources that:

(a) have a commercial operation date, as verified by DOER, on or after January 1, 2013;

(b) are qualified by DOER as eligible to participate in the Class I enewable portfolio standard ("RPS") program, and to sell RECs under the RPS program, pursuant to G.L. c. 25A, § 25; and

(c) are determined by the Department: (1) to provide enhanced electricity reliability within the Commonwealth; (2) to contribute to moderating system peak-load requirements; (3) to be cost effective to Massachusetts electric customers over the term of the contract; and (4) where feasible, to create additional employment and economic development in Massachusetts;

(d) are determined by the Department to be a cost-effective mechanism for procuring low-cost renewable energy on a long-term basis; and

(e) facilitate the financing of renewable energy generation.

As demonstrated in the Joint Testimony at pages 32-45, and accompanying exhibits, the proposed 24 PPAs filed herewith are low-cost, cost-effective renewable energy contracts that facilitate the financing of renewable generation and otherwise satisfy the requirements of Section 83A and 220 C.M.R. § 21.00 et seq..

5. The economics of each of the projects depend in part on the developer's ability to qualify for certain tax credits, which require that the developers make certain financial commitments before the end of calendar year 2013. Such financial commitments are tied to receipt of an adequate level of assurance that their PPAs will be approved. Thus, any delay in approving the PPAs that jeopardizes the project's ability to qualify for the tax credit could result in increased prices to customers if the project were terminated and had to be re-bid in a later RFP. Accordingly, the Distribution Companies support the Department's review and approval of the 24 PPAs expeditiously.

WHEREFORE, NSTAR Electric respectfully requests that the Department:

(1) Determine that the six proposed PPAs are consistent with Section 83A and 220 C.M.R. 21.00 et seq.;

(2) Approve the proposed amendments to the Company's Long-Term Renewable Contract Adjustment Mechanism, M.D.P.U. No. 164B, and

(3) Issue such other and further orders as may be necessary and appropriate.

Respectfully Submitted,

NSTAR ELECTRIC COMPANY

By its attorneys,

Danielle C. Winter
____

Danielle Winter, Esq.
Donald W. Boecke, Esq.

Keegan Werlin LLP
265 Franklin Street
Boston, MA 02110
(617) 951-1400

Dated: September 20, 2013

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	)	D.P.U. 13-146
Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	)	D.P.U. 13-147
Petition of NSTAR Electric Company for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	)	D.P.U. 13-148
Petition of Western Massachusetts Electric Company for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	)	D.P.U. 13-149

JOINT DIRECT TESTIMONY OF
JEFFERY S. WALTMAN, CORINNE M. ABRAMS and
ROBERT S. FURINO

DATED: September 20, 2013

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
d/b/a UNITIL

MASSACHUSETTS ELECTRIC COMPANY and NANTUCKET ELECTRIC COMPANY d/b/a NATIONAL GRID

NSTAR ELECTRIC COMPANY

WESTERN MASSACHUSETTS ELECTRIC COMPANY

Joint Direct Testimony of
Jeffery S. Waltman, Corinne M. Abrams and Robert S. Furino

I. INTRODUCTION

Q. Mr. Waltman, please state your full name and business address.

A. My name is Jeffery S. Waltman. My business address is One NSTAR Way, Westwood, Massachusetts 02090.

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

A. I am Manager, Planning and Power Supply for Massachusetts regulated operating companies of Northeast Utilities which includes NSTAR Electric Company (“NSTAR Electric”) and Western Massachusetts Electric Company (“WMECO”) (hereinafter collectively “NU”).

Q. Please describe your present responsibilities.

A. As Manager of Planning and Power Supply, I am responsible for securing a reliable and least-cost energy supply on behalf of customers serviced by NU. My responsibilities include the management of Basic Service supply, long term contracts, and for compliance with the Renewable Portfolio Standards.

Q. Please describe your education and professional background.

A. I graduated from Arizona State University in Phoenix with a Bachelor's Degree in Finance. From 1983 through 2003, I worked at Arizona Public Service Company and held various positions including short term trader for retail electricity and later held the position of commodity trader where I managed a coal trading book. In 2004 I took a position with the Colorado River Commission of Nevada as Power Supply Manager in charge of the electric and gas trading needs of the Southern Nevada Water Authority. In 2006 I joined Baltimore Gas and Electric as Lead Power Supply Analyst in charge of administering POLR (Provider of Last Resort) auctions for Maryland consumers. Additionally I managed a residential, commercial and industrial demand response programs. In February of 2008, I came to work for NSTAR Electric.

Q. Have you previously testified in proceedings before the Department?

A. I have submitted testimony and exhibits on behalf of NSTAR Electric before the Department of Public Utilities (the "Department") in D.P.U. 11-93, D.P.U. 12-36, D.P.U. 12-99 and D.P.U. 13-76 on NSTAR Electric's semi-annual reconciliation filings for NSTAR Green service. I also testified in D.P.U. 08-52 regarding NSTAR Electric's provision of retail access to competitive REC suppliers. I also have filed exhibits and affidavits in support of NSTAR Electric's quarterly solicitations for

Basic Service.

Q. Ms. Abrams, please state your name and business address.

A. My name is Corinne M. Abrams. My business address is National Grid, 100 East Old Country Road, Hicksville, N.Y. 11801

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

A. I am Manager of Environmental Transactions, Energy Procurement of National Grid. I am contributing to this joint testimony on behalf of Massachusetts Electric Company and Nantucket Electric Company together d/b/a National Grid ("National Grid").

Q. Please describe your present responsibilities.

A. I manage the competitive solicitations for renewable energy projects, including negotiations for power purchase agreements ("PPAs") for renewable energy projects. This includes competitive solicitations to comply with Section 83A of the Massachusetts Green Communities Act (St. 2008, c. 169, § 83A, as amended by §36, An Act Relative to Competitively Priced Electricity, St. 2012, c. 209), (hereinafter "Section 83A"), and in Rhode Island, the Long-Term Contracting Standard for Renewable Energy Act, R.I.G.L. § 39-26.1.1 et seq. ("Long-Term Contracting Standard") and enrollments under the Distributed Generation Standard Contracts Act, R.I.G.L . § 39-26.2.1 et seq. I am also involved with the development of National Grid's renewable energy policies.

Q. Please describe your education and professional background.

A. I graduated from Drexel University in 2005 with a Bachelor of Science Degree in Civil Engineering. I received a Masters in Business Administration in Finance and Investments from Baruch College in May 2013. In July 2005, I joined KeySpan Corporation as an Engineer in Generation Operations. I was accepted into the Engineering Rotation Program and held various positions in Power Engineering, Generating Plant (Steam and Gas Turbine) Operations, and Maintenance Services. In November 2009, as part of a management development initiative, I joined Energy Portfolio Management as the technical advisor to the Senior Vice President. I was promoted to my current position in June 2011.

Q. Have you previously testified in proceedings before the Department or in other jurisdictions?

A. I have not testified before the Department. I have testified, however, before the Rhode Island Public Utilities Commission on renewable energy resource matters.

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

A. My name is Robert S. Furino. My business address is 6 Liberty Lane, Hampton, N.H. 03482.

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

A. I am Director, Energy Contracts at Unitil Service Corp. I am contributing to this joint testimony on behalf of Fitchburg Gas and Electric Light Company d/b/a Unitil ("Fitchburg" or "Unitil").

Q. Please describe your present responsibilities.

A. As Director of Energy Contracts for Unitil Service Corp., I am responsible for developing, implementing and supporting Unitil's energy procurement and contracting strategies to ensure a reliable and cost-effective natural gas and electric energy supply for Unitil's regulated distribution utilities, including Fitchburg. I am also responsible for the management of retail choice programs of Unitil's regulated distribution utilities.

Q. Please describe your education and professional background.

A. I received my Bachelor of Arts degree in Economics from the University of Maine in 1991, and completed coursework toward a Master of Arts degree also at the University of Maine. I joined Unitil in March 1994 as an Associate DSM Analyst in the Regulatory Services Department and have worked in the Regulatory, Product Development, Finance and Energy Contracts departments, while assuming positions of increasing responsibility. I have been in my current position since 2008.

Q. Have you previously testified in proceedings before the Department?

A. Yes, I have testified before the Department with regard to Fitchburg's Gas Integrated Resource Plans and other gas related matters. I have also prepared or directed the preparation of Fitchburg's electric Basic Service Request for Proposals Bid Evaluation Reports and related filings as well as the proceeding to obtain Department approval of Fitchburg's long-term REC supply agreement that was entered into pursuant to Section 83 of the Green Communities Act. In addition, I have testified before the New Hampshire Public Utilities Commission on both electric and gas matters and before the Maine Public Utilities Commission on gas matters.

Q. What are the Distribution Companies proposing in this proceeding?

A. Section 83A requires electric distribution companies in Massachusetts, in collaboration with the Department of Energy Resources ("DOER"), to jointly undertake competitive bid solicitations to enter into long-term contracts for renewable energy. NSTAR Electric, WMECO, Fitchburg and National Grid have successfully done so and the companies (collectively "the Distribution Companies") have each entered into individual contracts to acquire a pro rata share of the total renewable energy output and renewable energy certificates ("RECs") of six proposed wind energy projects in New England over the contracts term of fifteen (15) or twenty (20) years. The six wind projects and the principal developer/contract counterparty are as follows:

Table 1

PROJECT NAME	PRINCIPAL DEVELOPER	CONTRACT COUNTERPARTY	OUTPUT (MW)	CONTRACT TERM (Yrs.)
Wild Meadows	Iberdrola Renewables	Iberdrola Renewables, LLC	75.9	15
Fletcher Mountain	Iberdrola Renewables	Iberdrola Renewables, LLC	97.1	15
Oakfield Wind	First Wind	Evergreen Wind Power II, LLC	147.6	15
Bingham Wind	First Wind	Blue Sky West, LLC	186	15
Passamaquoddy Wind	Exergy Development Group	Passamaquoddy Wind, LLC	38.2	15

Peskotmuhkati Wind	Exergy Development Group	Peskotmuhkati Wind, LLC	20	20

Each of the Distribution Companies is submitting, in their respective proceeding, individual PPAs for all six projects for the Department's review and approval pursuant to Section 83A. Thus, there are a total of twenty four (24) PPAs collectively submitted for the Department's review and approval as a result of this competitive Section 83A solicitation.

Because the Distribution Companies conducted all aspects of this competitive procurement jointly (e.g., bid solicitation, bid evaluation and contract negotiation), pursuant to Section 83A and in collaboration and coordination with DOER, the issues of law and fact are common to all 24 PPAs. Accordingly, the Distribution Companies have prepared and are sponsoring this Joint Testimony, submitted in each of the four Department proceedings, in support of the collaborative joint solicitation process and the resulting 24 PPAs.

Q. What is the purpose of your joint testimony?

A. Our testimony will describe the Distribution Companies' participation in the joint, collaborative renewable energy competitive solicitation and demonstrate that: (1) the Distribution Companies' procurement of PPAs with the six wind projects satisfies the requirements of Section 83A and the Department's regulations promulgated thereunder relating to the solicitation of long-term contracts from renewable energy developers; (2) the Distribution Companies have followed the provisions of the Request for Proposal Process approved by the Department on March 29, 2013 in D.P.U. 13-57 in selecting and awarding the contracts; and (3) the proposed 24 PPAs compare favorably on price and non-price factors to the range of renewable energy resources available in the marketplace today.

Q. What exhibits are you sponsoring in your testimony?

A. We are sponsoring 12 exhibits, including:

- Exhibit JU-1 [CONFIDENTIAL], Tabs A-D, are the four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to the Wild Meadows wind project;
- Exhibit JU-2 [CONFIDENTIAL], Tabs A-D, are the four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Fletcher Mountain wind project;
- Exhibit JU-3 [CONFIDENTIAL], Tabs A-D, are the four individual 15-year PPAs executed by NSTAR Electric, WMECO,National Grid and Fitchburg applicable to Oakfield Wind;
- Exhibit JU-4 [CONFIDENTIAL], Tabs A-D, are the four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Bingham Wind;
- Exhibit JU-5 [CONFIDENTIAL], Tabs A-D, are the four individual 15-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Passamaquoddy Wind;
- Exhibit JU-6 [CONFIDENTIAL], Tabs A-D, are the four individual 20-year PPAs executed by NSTAR Electric, WMECO, National Grid and Fitchburg applicable to Peskotmuhkati Wind.

Together, these 24 PPAs represent the purchase of 100 percent of the total energy output from each of the six projects.

- Exhibit JU-7 is a copy of the Request for Proposals ("RFP") approved by the Department in D.P.U. 13-57, and includes the Draft PPA (with subsequent revision), which was used by the Distribution Companies to jointly solicit and procure the contracts.

- Exhibit JU-8 [CONFIDENTIAL] summarizes the overall bid scoring results of the Distribution Companies' bid analysis prior to initial selection of the Short List.

- Exhibit JU-9 [CONFIDENTIAL] summarizes the non-price scores awarded by the Distribution Companies for the projects evaluated for non-price factors.

- Exhibit JU-10 [CONFIDENTIAL] displays the fifteen bids selected from the overall scoring results of Exhibit JU-8 for inclusion on the Short List and provided an opportunity to refresh bid prices.

- Exhibit JU-11 [CONFIDENTIAL] is the refreshed ranking and selection of the Final Short List subsequent to the opportunity afforded to short listed bidders to refresh prices. The projects on the Final Short List selected for contract negotiation are highlighted on Exhibit JU -11.

- Exhibit JU-12 [CONFIDENTIAL] is the common market price forecast prepared by the Distribution Companies' consultant, ESAI.

In addition, also accompanying this filing are consolidated Distribution Company Work Papers (hereinafter "WP Support") that contain the documentary support for the solicitation and subsequent bid evaluation process followed by the Distribution Companies in this joint renewable energy competitive procurement. The WP Support is arranged as follows:

- Tab A - List of entities sent the RFP;

- Tab B - Firms providing notice of intent to bid;

- Tab C - [CONFIDENTIAL – CD-ROM ONLY] complete bid package for bids received;

- Tab D - [CONFIDENTIAL – CD-ROM ONLY] Bid evaluation and scoring spreadsheet model, in Excel format (Bid Analysis June27.xlsx), prior to selection of short list;

- Tab E - [CONFIDENTIAL – CD-ROM ONLY] Bid evaluation and scoring spreadsheet model, in Excel format (Bid Analysis July17.xlsx), with refreshed prices from short list bidders;

- Tab F - [CONFIDENTIAL] redline of sample PPA from each developer against Draft RFP;

- Tab G - [CONFIDENTIAL] redline of sample PPA from each Distribution Company for a single project against Draft RFP.

For filing purposes, the confidential prices and other commercially sensitive information contained in the WP Support and as contained in the Exhibits – except for Exhibit JU-7 – are redacted and will be presented to the Department under seal and subject to a Motion for Protective Treatment.

Q. Are the Distribution Companies sponsoring additional witnesses to support this filing?

A. Yes. NSTAR Electric and WMECO are also sponsoring in D.P.U. 13-148 and 13-149, respectively, the testimony of Mr. Richard Chin, who is Manager of Rates for NU. Mr.Chin's testimony will describe NSTAR Electric's and WMECO's Long-Term Renewable Contract Adjustment Tariff and discuss cost recovery issues and rate design proposals relating to the proposed Section 83A contracts. National Grid is sponsoring the cost recovery testimony of Scott M. McCabe, Principal Program Manager, New England Electric Pricing in D.P.U. 13-147. Mr. McCabe's testimony will describe National Grid's proposed revisions to Renewable Energy Recovery Provision and Basic Service Adjustment Provision needed to allow for the recovery of costs relating to these proposed Section 83A contracts. Unitil describes its cost recovery process in separate testimony presented by Mr. Furino in D.P.U. 13-146.

Q. Please describe how you have organized this joint testimony.

A. Because of prevailing common issues of law and fact, identical joint testimony is submitted simultaneously in each of the four proceedings initiated to review each of the Distribution Companies' six PPAs. The joint testimony first provides an overview of Section 83A and the filing requirements in the Department's regulations adopted pursuant to Section 83A for review and approval of executed PPAs. Next the joint testimony describes and discusses the solicitation process, including bid scoring and project selection. The testimony next covers the specifics of each of the 24 PPAs and describes how they satisfy the requirements of Section 83A and the Department's regulations.

Q. Do you have any introductory comments concerning the 24 individual PPAs submitted for Department review?

A. Yes. As previously indicated in Table 1, above, the four Distribution Companies have each entered into contracts with three principal developers/sponsors, with each developer committing two separate wind projects. While the process thus produced 24 separate PPAs, the Department's review of the 24 individual PPAs will be aided by an appreciation of how these agreements were negotiated and structured.

The four Distribution Companies jointly negotiated all contracts from a single Draft PPA. A copy of this Draft PPA was distributed with the RFP and is included in

Exhibit JU-7. The Distribution Companies pursued their joint negotiations with each of the three principal project developers/sponsors separately, leading to the development of three counterparty contract "templates;" one for use with each developer. There are minor variations in terms among the three templates, as each template reflects the terms and/or contract language that were most important to each developer. Included in the Distribution Companies' WP Support accompanying this filing, Tab F, is a redline comparison of a PPA executed by each of the three project sponsors (Iberdrola Renewables, First Wind and Exergy Development) against the Draft PPA which highlights the variations among the three counterparty "templates."

When the Distribution Companies came to final terms with each of the three developers, the "template" was used for final contracts for both projects offered by that developer. The substantive contract terms that vary between two projects sponsored by the same developer would be the project-specific description, achievement dates for critical milestones and commercial operation, the amounts to be purchased from each project, the price, the collateral requirements and the delay damages (the collateral and the delay damages are both a function of the amount of energy to be purchased by each Distribution Company). Thus, for example, the substantive terms of the NSTAR PPA with Iberdrola for the Fletcher Mountain project are the same (except as described above) as the NSTAR PPA with Iberdrola for the Wild Meadows project.

Q Are the four PPAs for each project signed individually by the four Distribution Companies identical?

A. All four PPAs related to a particular project are substantially identical with regards to the principal contract terms, such as price and contract duration. However, the quantities purchased vary as each Company contracted for its pro rata share of the output.[1] In addition, due to International Financial Reporting Standards affecting National Grid, the breakdown in the "bundled" price for energy and RECs in each contract differs from that breakdown for NU and Unitil, which follow U.S. generally accepted accounting principles. However, the total bundled price for energy and RECs is the same in each contract.

Q. Are there any other variations among the Distribution Company PPAs pertaining to the same project?

A. There are also variations among the four PPAs for a particular project with respect to credit terms, attributable primarily to each Distribution Company's standard credit practices. However, the four PPAs executed by the Distribution Companies covering an individual project are substantially similar.

Included in the Distribution Companies' WP Support, Tab G, is a redline comparison of a PPA executed by each of the four Distribution Companies for a single project (e.g., Fletcher Mountain Wind Project) against the Draft PPA which highlights the

[1] Section 83A provides that the apportioned share "shall be calculated and based upon the total energy demand from all distribution customers in each service territory of the distribution companies." Thus, the pro rata share of each project's output equates to: National Grid- 45.9%; NSTAR-45.4%; WMECO-7.7% and Fitchburg-1.0%.

variations among the four Distribution Company PPAs with respect to the same project.

II. OVERVIEW OF GREEN COMMUNITIES ACT REQUIREMENTS

Q. What is the basis for the Distribution Companies' request for approval of a long-term renewable contract with each Developer?

A. The Distribution Companies are requesting approval of the twenty four long-term renewable contracts in compliance with Section 83A of the Green Communities Act and the Department's regulations set forth at 220 C.M.R. § 21.00 et seq., as promulgated in D.P.U. 13-42.

Q. How do the provisions of Section 83A of the Green Communities Act relate to the Distribution Companies' requested approval?

A. Section 83A requires the Department to adopt rules and regulations necessary to implement the provisions of Section 83A pertaining to the procurement of long-term contracts for renewable energy. The Department fulfilled its mandate under Section 83A by opening a rulemaking investigation in D.P.U. 13-42 and adopting final regulations as set forth in 220 C.M.R. § 21.00 et seq.. See Order Adopting Final Regulations, D.P.U. 13-42-A (May 9, 2013). The Distribution Companies' filing is made in accordance with the Section 83A and the Department's regulations.

Q. Would you please review the key provisions of Section 83A and the Department's regulations as those requirements pertain to the Distribution Companies' filing herein?

A. In Section 83A, a long-term contract is defined as a contract with a term of 10 to 20 years. All distribution companies must jointly solicit proposals from renewable energy developers using a competitive bidding process. Provided that reasonable proposals are received, each distribution company will enter into cost-effective long-term contracts for their apportioned share of selected projects to facilitate the financing of renewable energy generation. Distribution companies are not obligated to enter into long-term contracts under Section 83A to the extent that, in the aggregate, the contract volumes would exceed 4 percent of the total energy demand from all distribution customers in the combined service territories.[2] In addition, a distribution company may decline to consider contract proposals having terms and conditions that it determines would place an unreasonable burden on the distribution company's balance sheet. All proposed contracts resulting from the Section 83A procurement process must be reviewed and approved by the Department before those contracts become effective. The Department's regulations establish the standard of review that will be applied by the Department in determining whether to approve a proposed contract.

Collectively, Section 83A and the Department's regulations empower distribution companies to consider multiple contracting methods, including long-term contracts for RECs, for energy, and for a combination of both RECs and energy.

[2] Section 83A further provides that 10 percent of the 4 percent procurement obligation shall be excluded from the joint solicitation and reserved for "newly developed, small, emerging or diverse renewable energy distributed generation facilities…."

Q. Does the Distribution Companies' filing also meet the requirements of the regulations issued by the Department under Section 83A regarding development and issuance of the RFP?

A. Yes. The Department issued emergency regulations on March 1, 2013 in D.P.U. 13-42. After receiving comments from interested parties, the Department subsequently, on May 9, 2013, adopted final regulations implementing Section 83A. See D.P.U. 13-42-A.

In accordance with the regulations, the Distribution Companies consulted with DOER and the Attorney General. The parties worked to develop an RFP incorporating a timetable and method of solicitation that was submitted March 1, 2013 for the Department's review and approval. That filing was assigned docket number D.P.U. 13-57. On March 29, 2013 the Department in D.P.U. 13-57 approved the RFP (provided as Exhibit JU-7). On April 1, 2013 the RFP was issued by the Distribution Companies and DOER to an extensive list of potential bidders.

Q. Please describe the eligibility criteria for renewable energy projects.

A. Section 83A and the Department's regulations at 220 C.M.R. § 21.00 et seq. require that long-term contracts entered into by a distribution company must be executed with renewable energy generation sources that:

(a) have a commercial operation date, as verified by DOER, on or after January 1, 2013;

(b) are qualified by DOER as eligible to participate in the Class I renewable portfolio standard ("RPS") program, and to sell RECs under the RPS program, pursuant to G.L. c. 25A, § 25; and

(c) are determined by the Department: (1) to provide enhanced electricity reliability within the Commonwealth; (2) to contribute to moderating system peak-load requirements; (3) to be cost effective to Massachusetts electric customers over the term of the contract; and (4) where feasible, to create additional employment and economic development;

(d) are determined by the Department to be a cost-effective mechanism for procuring low-cost renewable energy on a long-term basis; and

(e) facilitate the financing of renewable energy generation.

Q. Please describe a distribution company's options for the use of energy and RECs obtained through long-term contracts pursuant to Section 83A and the Department's regulations.

A. Section 83A and the Department's regulations provide that after purchasing renewable energy, or RECs, or both, a distribution company may: (1) sell the energy to its Basic Service customers, and retain RECs for the purpose of meeting the distribution company's annual RPS obligation; (2) sell the energy into the wholesale electricity spot market, and sell the purchased RECs through a competitive bid process; or (3) select an alternative approach, subject to review and approval by the Department (see 220 C.M.R. §21.06).

To the extent a distribution company chooses to sell the energy into the wholesale electricity spot market and the RECs through a competitive bid process, the company must: (1) calculate the net cost of payments made under the long-term PPAs against the proceeds obtained from the sale of energy and RECs; (2) credit or charge all distribution customers the difference between the contract payments and proceeds through a uniform, fully-reconciling annual factor in distribution rates, subject to review and approval by the Department; and (3) design a reconciliation process that allows the company to recover all costs incurred under such contracts, subject to review and approval by the Department.

Q. Please describe the relationship between Section 83A and the Commonwealth's RPS requirements.

A. As noted above, one eligibility criterion under Section 83A and the Department's regulations is that the renewable energy generation resource from which energy and/or RECs are procured under a long-term contract must be eligible to participate in the Commonwealth's RPS program and to sell RECs under the program. Although the overall long-term contracting obligation established by Section 83A is separate and distinct from a distribution company's obligation to meet applicable RPS requirements pursuant to G.L. c. 25A, § 11F, a distribution company may use RECs purchased under such a long-term contract to satisfy its RPS obligations.

Q. Please describe further the proceedings in D.P.U. 13-57.

A. Section 83A requires the Distribution Companies to develop a timetable and method for solicitation and execution of long-term contracts in consultation with DOER and the Attorney General, and subject to the review and approval of the Department. On March 1, 2013, the Distribution Companies jointly filed a request for approval of a proposed timetable and method for soliciting proposals for renewable energy through a competitive RFP process. The Department docketed the matter as D.P.U. 13-57 and received comments from interested stakeholders. Thereafter the Department approved the method of solicitation and timetable of the RFP by order dated March 29, 2013. The Department-approved RFP, as distributed to all prospective bidders, is included in Exhibit JU-7.

Q. Please describe the process of formulating the RFP as proposed, and as approved by the Department.

A. The RFP filed for Department approval was developed jointly by the Distribution Companies in consultation with DOER and the Attorney General and was based largely on the RFP approved by the Department in D.P.U. 10-76 in connection with the renewable procurement obligation of GCA Section 83. The RFP development process involved a careful consideration of a range of logistical and substantive issues relating to the creation of a standardized methodology for bid solicitation and evaluation. The Distribution Companies submitted the RFP with the expectation that the Department's approval of the RFP would promote the transparency, consistency and objectivity of the solicitation process, which in turn, would facilitate the Department's subsequent review of individual contracts once executed and submitted by the Distribution Companies for Department review.

Q. Please describe the solicitation method set forth in the RFP.

A. The Distribution Companies and DOER agreed to a joint collaborative process for the solicitation of long-term contracts for renewable energy. Specifically, the Distribution Companies, in coordination with DOER, agreed to: (1) jointly issue the RFP and associated forms; (2) establish a standardized framework for the evaluation of the bids and the negotiation of the long-term contracts; and (3) jointly act in evaluating bids and negotiating long term contracts. As noted in the RFP, the purpose of the consolidated approach of this joint solicitation was to provide prospective bidders with a single set of bid submittal and evaluation requirements to simplify and facilitate the bidding process.

Although DOER served in a consultative role to the Distribution Companies in the development of the bid evaluation process and provided coordination of the bid solicitation process, the Distribution Companies ultimately were jointly responsible for evaluating bids pursuant to the RFP bid criteria, selecting from conforming bids and negotiating contracts with selected bidders. As noted above, and as required by paragraph 2.6 of the RFP and section 8.2 of each contract, once the Distribution Companies negotiated and executed long-term PPAs, the Companies must submit the executed PPAs to the Department for the Department's review and approval.

Q. Please describe the bid evaluation process, as described in the RFP.

A. In the RFP approved by the Department in D.P.U. 13-57 (see Exhibit JU-7), the Distribution Companies proposed a three-stage bid evaluation process (RFP Section 2.1). The first stage identifies bidders who comply with certain eligibility and threshold requirements as set forth in Section 83A and the Department's regulations (RFP Section 2.2). The second stage consists of a combined price and non-price evaluation and scoring of bids that pass the first stage review (RFP Section 2.3). The third stage consists of additional risk assessments and consideration of the bids from a portfolio perspective (RFP Section 2.4). As more fully discussed below, the process also allowed bidders that make the short list an opportunity to refresh prices.

III. SOLICITATION FOR LONG-TERM RENEWABLE CONTRACTS

Q. Have the Distribution Companies solicited long-term contracts from renewable energy developers to satisfy the requirements of Section 83A and the Department's regulations?

A. Yes. On April 1, 2013, the Distribution Companies, together with DOER, jointly distributed the Department-approved RFP to more than 300 individuals with an interest in developing renewable projects from a list compiled by the Distribution Companies and DOER. The list of entities receiving the RFP is provided in WP Support, Tab A. Pursuant to the timetable set forth in Section 3.1 of the RFP, a Bidders' Conference was conducted on April 16, with written submissions of bidders' questions and a Notice of Intent to Bid due April 22. All questions were answered in writing and all written documents associated with the solicitation were posted to a website maintained for the solicitation at <www.marfp.com>. The list of RFP recipients that subsequently submitted a Notice of Intent to Bid is provided in WP Support, Tab B.

Q. How many bids were submitted in response to the RFP?

A. By the May 6, 2013 deadline established in the RFP for Submission of Proposals, the Distribution Companies received 112 price offers for 40 projects, totaling 2,357 MW of renewable generation. A copy of each bid package (i.e., all documents that comprise the bid) submitted to the Distribution Companies in response to the RFP is included in WP Support on CD-ROM [CONFIDENTIAL]. It should be noted that two additional bids received only by National Grid, in contravention of the RFP requirements in Section 1.5 that each bid must be sent to all Distribution Companies, were disregarded as invalid and were not considered.

Q. Please describe generally the process the Distribution Companies followed to jointly evaluate and score the bids received.

A. All three stages of bid evaluation described in the RFP and further discussed below were conducted by the Distribution Companies jointly and collaboratively. Each Distribution Company exercised its judgment, contributed its experience and expertise, and arrived at conclusions and assessments collaboratively and collectively. Accordingly, the Distribution Companies produced a single, consensus evaluation and scoring of each project and a single ranking of all bid proposals. At appropriate junctures in the evaluation process, the Distribution Companies also conferred with DOER in its coordination function. For example, the Distribution Companies provided DOER with copies of all bids as received; conferred with DOER regarding the Companies' development of the short list; discussed the results of refreshed prices by short-listed bidders; and discussed with DOER selection of the amount of energy to target for contract with respect to the top short-listed projects and advised DOER of the subsequent execution of the PPAs.

Q. Can you please elaborate on the elements of the first stage evaluation?

A. The first stage evaluation is a qualitative assessment of the bids which considers a variety of criteria designed to determine if a project merited moving forward in the process. As part of their proposals, bidders were required to fill out a "Bidder Response Form." This form was designed to give the Distribution Companies the information needed to determine if the proposed project met the first stage criteria. As set forth in the RFP, Section 2.2, first-stage criteria fall into three categories:

(1) Eligibility: does the developer have development rights; will it be a RPS Class I facility; is the offer for energy and/or RECs on a unit specific unit contingent basis; is the term 10-20 years; and is the proposed size at least 1MW.

(2) Threshold: is the project schedule reasonable; does the developer have site control; is the technology viable; does the bidder have sufficient experience in project development; does it contribute to moderating peak load; does it contribute to electrical reliability in Massachusetts; does it contribute to employment and economic development; can the developer meet the security requirements for developmental and operating period security; does the project create unreasonable balance sheet impacts for the distribution companies; is a contract necessary to facilitate financing of the project; and was it submitted in a timely manner.

(3) Other Minimum Requirements: was the form of pricing allowed under the RFP; did the developer certify that the bid was firm for 180 days, and was the bid package

complete.

The first stage evaluation is not a quantitative, numeric scoring of the bids, but rather a subjective but uniformly applied determination whether the bid contains sufficient information needed to continue with a detailed evaluation of the offer.

Q. How many of the bids received by the Distribution Companies complied with the eligibility and threshold requirements as set forth in Section 83A and the Department's regulations?

A. At the conclusion of stage one evaluation, all 40 of the bids received by the Distribution Companies complied with the eligibility, threshold and minimum bid requirements. Thus, all 40 bids proceeded under the RFP to stage two evaluation, for price and non-price scoring.

Q. Were there any disagreements or discrepancies among the Distribution Companies with respect to stage one evaluations?

A. No, the Distribution Companies were unanimous in their assessment that all bids fulfilled stage one requirements.

Q. Please describe the Distribution Companies' price and non-price evaluation of the bids that passed the first-stage review.

A. As described in Section 2.3 of the RFP, for each submission that passed the eligibility and threshold evaluation criteria of stage one, the Distribution Companies conducted a quantitative scoring of both price and non-price factors. As specified in the RFP, price factors were weighted at 80 percent of total bid score and non-price factors were weighted at 20 percent. In advance of the bidding, the Distribution Companies and the DOER together formulated both "price evaluation criteria" and "non-price evaluation criteria."

The price evaluation criteria consisted of a comparison of bid costs, on both a unitized and a net present value basis, to a common market price forecast developed by ESAI. See RFP § 2.3.1. The ESAI market price forecast is enclosed as Exhibit JU-12 [CONFIDENTIAL]. The Distribution Companies discussed and agreed to a single, common spreadsheet model that would perform the calculations required to produce a consistent, comparable estimate of the above-market costs for each proposal. The project with the most favorable price/cost (in comparison to the market forecast) received the maximum bid price score of 80 points. Projects thereafter were awarded fewer points for each discounted $/MWh of value below the highest scored project. An electronic copy of the bid analysis model (in Excel format, with all cell values and formulae intact) is included in the WP Support on CD-ROM [CONFIDENTIAL].

Q. How were the non-price attributes of the bids scored under stage two?

A. The non-price evaluation criteria consisted of five evaluation factor categories: (1) siting and permitting; (2) project development status and operational viability; (3) experience and capability of bidder and project team; (4) financing; and (5) exceptions to the Draft PPA. See RFP § 2.3.2. The weights (i.e., the number of potential points awarded) to be assigned by the Distribution Companies to each category were established in advance through discussions and collaboration with

DOER. Each category also contained multiple criteria within each category. Non-price evaluations were conducted uniformly by the Distribution Companies jointly for each submission, based on the information contained in the bid. After each Company completed a preliminary review of all bids for non-price considerations, the Distribution Companies met to collaboratively evaluate and produce single bid scores for each project. Documentation supporting the points awarded to each project for non-price factors is provided in Exhibit JU-9 [CONFIDENTIAL].

Q. Were all projects evaluated on both price and non-price factors?

A. All projects were evaluated in the bid analysis model for above-market costs and assigned points for price. However, once the price scores were assigned, only those projects that received at least 60 price points were evaluated on non-price factors. The combined energy output of the projects receiving at least 60 price points was more than 5 times the quantities the Distribution Companies intended to procure through this initial solicitation. Thus, it was not necessary to proceed further down the project list with an evaluation of non-price factors beyond the top 15 projects based on price points.

Q. What happened after the Distribution Companies assigned points for the price and the non-price evaluation factors?

A. Once the projects were evaluated as described above for both price and non-price features, the points were added together and the projects were ranked based upon total awarded points (Exhibit JU-8 [CONFIDENTIAL]). A total of 15 projects completed both price and non-price scoring. At this point, the Distribution Companies were ready to consider selection of a short list.

Q. What criteria did the Distribution Companies use in selecting a short list?

A. In evaluating how many of the top-scoring projects to include in the short list, the Distribution Companies considered both the rankings from the second stage evaluation as well as the size (output) of each project in relation to the total output the Distribution Companies intended to procure through this solicitation. The Distribution Companies selected for the initial short list all fifteen projects that scored highest on price factors and were scored on non-price factors. See Exhibit JU-10 [CONFIDENTIAL]. Together these projects represented about 4 million MWH, as compared to the Company's intended goal of purchasing approximately 850,000 MWH under the RFP (1.8% of combined territory load obligation). Bidders were then informed whether they were placed on the short list and that more projects were targeted for the short list than would ultimately proceed to contract. Short-listed Bidders were told that their ability to place high on the short list and be selected for contract negotiations would depend on their ability to improve their prices thereby improving their price scores. See RFP § 2.3.2.2.

Q. Did the Distribution Companies note any other changes in the solicitation process in developing the short list?

A. Yes, the Distribution Companies advised all bidders making the short list to consider an external market development when making their refreshed bids. After the

Distribution Companies had issued the RFP but before the projects were selected, ISO New England Inc. ("ISO-NE"), the independent system operator that administers and operates under FERC supervision the bulk wholesale electricity markets in New England, filed with FERC revised market rules governing market prices for electricity delivered into ISO-NE's energy markets. In essence, the revised market rules, once accepted by FERC, introduce the possibility of <u>negative</u> energy prices for certain locational marginal prices ("LMP") in certain instances. Such instances include, for example, where load conditions across the region are particularly low or where transmission constraints might prevent the efficient delivery of energy generated at particular nodes on the grid. In other words, with the new revised LMP rules that allow for <u>negative</u> LMPs, energy delivered from a renewable project into the market at times of <u>negative</u> LMPs, instead of accruing credits (revenues) for the energy delivered would incur payment obligations to have ISO-NE accept the energy. The resulting possibility could, in effect, increase the cost of these fixed price PPAs to customers. The Distribution Companies sought to avoid this market risk on its customers occasioned by the market rule change.

Q. How did the Distribution Companies propose to protect their customers from the exposure created by the proposed change in ISO-NE's market rules?

A. The Distribution Companies, through a proposed addition to the Draft PPA, advised each bidder making the short list of ISO-NE's proposed change in market rules and asked that any refreshed bid pricing incorporate this risk, in recognition that the

Distribution Companies intended to insulate their customers from the liability of negative energy prices effectuated by the revised LMP market rule changes. A copy of the Distribution Companies' proposed modification to the Draft PPA related to this market rule change is included in Exhibit JU-7.

Q. **How did short listed bidders respond to this opportunity to refresh bids?**

A. The majority of the short-listed projects (11 out of 15) improved their price score by lowering their bid prices. Two projects increased their bid prices. One developer withdrew its bid entirely (occasioned by a setback in permitting, unrelated to the LMP rule change) and another submitted a non-conforming refreshed bid.

With the revised prices available, the Distribution Companies re-determined the price scores in the bid analysis spreadsheet model and re-ranked the bids. The result of the refreshed pricing provided the Distribution Companies with a revised short-list, comprised of thirteen wind-powered projects offered by six developers. Together, these 13 projects represented approximately 3.5 million MWH of renewable generation or approximately 7.5 percent of the combined territory load. The revised scoring and ranking after short list bidders had the opportunity to refresh prices is displayed in Exhibit JU-11 [CONFIDENTIAL]. The bid analysis model documentation showing the development of the revised project rankings based on refreshed pricing by short-listed bidders is contained in WP Support on CD-ROM [CONFIDENTIAL].

Q. Did the Distribution Companies ultimately proceed to contracts with each of the short-list bidders?

A. No. The list of projects on the refreshed short list was further evaluated during stage three. The Companies reviewed the bids on the refreshed short list for cost effectiveness, risk associated with project viability, the extent to which additional employment and economic development would be created and the value of diversity of resources by size and type. See RFP § 2.4.

Additionally, as a result of the favorable prices obtained from short-listed bidders, when compared to the Market Forecast, the Distribution Companies elected to exercise the flexibility under the RFP and consider contracting for more renewable energy than the 1.8 percent of combined load targeted initially in the RFP. The Distribution Companies, after consultation with DOER, elected to pursue PPAs with the six top projects on the refreshed short list (highlighted on Exhibit JU-11 [CONFIDENTIAL]), for a total of 3.5 percent of combined territory load.

Q. Can you elaborate on the Distribution Companies' determination to increase the contract quantities from 1.8 percent of load to 3.5 percent?

A. As referenced in Exhibit JU-11 [CONFIDENTIAL], the top four projects on the refreshed short list, assuming all went to contract, would be enough to satisfy the 1.8 of percent of load target for this initial solicitation. Exergy Development Group had the number one and number four projects at the top of the short list. First Wind had the project in the second position and Iberdrola Renewables had the number three project on the list. However, both Iberdrola and First Wind also submitted very attractive bids on alternative projects that were almost as highly scored (in comparison to the Market Forecast) as the top four projects. The close comparability of bid scores and offered prices, the diversity offered by three developers, each with two highly scored projects and the efficiency in contracting by negotiating both projects concurrently encouraged the Distribution Companies to consider contracting now for more than 1.8 percent of combined load. In addition, the uncertainty whether federal production tax credits and other economic supports would be extended beyond the current December 31, 2013 deadline also urged serious consideration now of the prices in the revised short list to fill as much of the Section 83A obligation to procure renewable energy equal to 3.6 percent of load as is commercially reasonable.

Thus, given the pricing offered; a weighted average levelized price of less than 8 cents per kilowatt-hour, the contracting efficiency and the uncertainty of the extension of tax credits the decision to look to contract with the top six projects on the short list was reasonable and in the best interests of customers.

IV. DESCRIPTION OF THE CONTRACTS AND CONSISTENCY WITH SECTION 83A AND THE DEPARTMENT'S REGULATIONS

Q. Please provide an overview of the PPAs proposed for approval.

A. As a result of the contract negotiations, the Distribution Companies executed PPAs with three principal developers (Iberdrola Renewables, First Wind and Exergy

Development), covering six projects. Individual PPAs have been signed covering each of the six projects by each of four entities: NSTAR Electric; WMECO; National Grid; and Fitchburg. While each Distribution Company is submitting and sponsoring herein its own six PPAs, covering its allocated share of each of the six projects, unless the Department approves all four PPAs covering each project, either party to the PPAs has the right to terminate the agreement, and a project is unlikely to go forward.

Q. Please describe the particulars of the PPAs executed by NSTAR Electric, WMECO, National Grid and Unitil governing the Passamaquoddy Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECs from the Passamaquoddy Wind Project over a term of 15 years. The project has a nameplate rating of 38.2 MW and is located in Washington County Maine. The price increases annually from year 1, at a fixed percentage. The contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Please describe the particulars of the PPAs executed by the four Distribution Companies governing the Peskotmuhkati Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECS from the Peskotmuhkati Wind Project over a term of 20 years. The Peskotmuhkati project has a nameplate rating of 20 MW and is located in Washington County Maine. The price for this project increases annually from year 1.

The contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Please describe the particulars of the PPAs executed by the four Distribution Companies governing the Oakfield Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECs from the Oakfield Wind Project over a term of 15 years. The project has a nameplate rating of 147.6 MW and is located in Oakfield, Maine. The price is fixed for the life of the contract. The contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Please describe the particulars of the PPAs executed by the four Distribution Companies governing the Bingham Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECS from the Bingham Wind Project over a term of 15 years. The project has a nameplate rating of 186 MW and is located in Bingham, Maine. The price is fixed for the life of the contract. The contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Please describe the particulars of the PPAs executed by the four Distribution Companies governing the Fletcher Mountain Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECs from the Fletcher Mountain Wind Project over a term of 15 years. The project has a nameplate rating of 97.1 MW and is located in Somerset County, Maine. The price is fixed for the duration of the contract. The contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Please describe the particulars of the PPAs executed by the four Distribution Companies governing the Wild Meadows Wind Project.

A. The Distribution Companies are seeking approval for the purchase of energy and RECs from the Wild Meadows Wind Project over a term of 15 years. The project has a nameplate rating of 75.9 MW and is located in Alexandria and Grafton, New Hampshire. The price is fixed for the duration of the contract. The proposed contract includes rights to other environmental attributes associated with the facility that may exist in the future, such as CO_2 emission credits.

Q. Do the RECs generated by these projects and included in the PPAs qualify under the Renewable Portfolio Standard program?

A. Each project is a wind generation facility which is a qualifying RPS Class I technology, as defined in 225 CMR §14.00. The contract requires that the seller sell and the buyer buy RECs from the facilities only to the degree that they qualify as RPS Class I resources under 225 CMR § 14.00.

Q. What are the Commercial Operation Dates associated with each project?

A. The proposed Commercial Operation Dates for each facility are as follows:

Passamaquoddy Wind	11-30-2015
Peskotmuhkati Wind	11-30-2014
Oakfield Wind	12-31-2015

Bingham Wind	12-31-2016
Fletcher Mountain Wind	12-31-2016
Wild Meadows Wind	12-31-2016

Q. How does each project enhance reliability?

A. The amount of new capacity provided by these facilities, totaling some 565 MW, will supplement the region's base of installed capacity and thereby increase the supply reserve margins. Wind-powered generation is variable in proportion to the wind speed, but on average can be relied upon to increase reserve margins. ISO-NE recognizes the capacity value of wind based on its production during both summer and winter periods. Because these projects will be price takers in the ISO-NE market, their output will be placed at the bottom of the bid stack in the ISO-NE dispatch. Accordingly, the wind output will displace the marginal production unit, which is likely to be either gas or oil, thereby increasing the reserve margins of those units. In addition, since wind power is a local resource, it increases the region's fuel diversity away from natural gas and oil, both of which are entirely imported into the region.

Q. How does each project contribute to moderating system peak load?

A. As a wind resource, the energy produced by these facilities will be bid into the energy market as a price taker. This will put the energy supply at the bottom of the supply stack, thereby reducing the amount of load to be met by the remaining generation fleet

Q. Please describe how the Distribution Companies determined that the proposed prices would be cost-effective for customers over the term of the contract.

A. The proposed prices in the PPAs for each of the six projects were solicited through an open, robust competitive bid process, which traditionally the Department has recognized as its preferred means of determining cost-effectiveness. See e.g., D.P.U. 07-64-A; D.T.E. 02-40; D.T.E. 99-60. The RFP was widely distributed to a list of approximately 300 entities active in the renewable generation market in the Northeast and nationally. It was also posted on a joint web site set up by the Distribution Companies and the DOER. Section 83A and the Department's regulations require the use of a competitive bid process for the procurement of renewable resources and the specific process followed by the Distribution Company was approved by the Department in D.P.U. 13-57. The RFP process was fairly administered and the results were evaluated against a common market price forecast provided by ESAI.

The PPAs with the six top projects represents "least cost" renewable contracts when compared to the other bids received, while taking into account certain non-price factors described above. Because the six projects selected for contract are the top proposals based upon the Distribution Companies evaluation of all bids received through a competitively bid procurement process, the PPAs are low cost and cost-effective.

Q. How do the costs for Energy and RECs under each of the PPAs compare with the market price for Energy and RECs?

A. The costs for Energy and RECs under the PPAs are less than the forecasted market price for Energy and RECs during all years of the contract. Overall, based on an analysis of the bid data, the cost of Energy and RECs under the PPAs for each of the six selected projects, based on commercial operation dates as reflected in the bids,[3] are less than forecasted market prices by a total of $1.2 billion, nominal, over the life of the PPAs.

1. Passamaquoddy Wind is below forecasted market prices by $96 million over the life of the fifteen (15) year contract.
2. Peskotmuhkati Wind is less than forecasted market prices by $61 million over the life of the twenty (20) year contract.
3. Oakfield Wind is less than forecasted market prices by $292 million over the life of the fifteen (15) year contract.
4. Bingham Wind is less than forecasted market prices by $390 million over the life of the fifteen (15) year contract.
5. Fletcher Mountain is less than forecasted market prices by $206 million over the life of the fifteen (15) year contract.
6. Wild Meadows is less than forecasted market prices by $171 million over the life of the fifteen (15) year contract.

All of the foregoing values are stated in nominal terms and are not discounted.

Q. **How were the below-market costs derived?**

A. Within the bid analysis spreadsheet model, provided as a working Excel file in the Distribution Company's WP Support, CD-ROM [CONFIDENTIAL], the cost of the estimated project output over the duration of the contract, is developed at the contract price and compared to the market value of the energy and RECs based on the market

3 During negotiations, the commercial operation dates for certain projects were extended, which would alter the calculation of below-market savings slightly.

forecast developed for use by the Distribution Companies in this solicitation by ESAI. The cumulative contract cost, net of projected market values of the energy and RECs, is developed under the "Net Nominal" tab of the bid analysis spreadsheet model and displayed on line 307.

Q. Does the fact that the contract costs are below forecasted market prices overall mean that the PPAs are cost effective?

A. Not necessarily. The market price forecast for energy and RECs produced by ESAI is a good faith estimate for market prices for energy and RECs over the terms of the contracts. A more accurate measure of actual "market prices" for these products is the result of a robust competitive process, such as this RFP, where bids were received representing 2,357 MW from 40 projects and 21 bidders with 112 price offers. As discussed more fully below, the projects selected scored highly against all bids received on both price and non-price factors and is therefore a low-cost, cost-effective resource for customers.

Q. **How does the value of energy delivered to the Delivery Point under each PPA compare with projects in other load zones?**

A. The scoring system the Distribution Companies and the DOER developed uses locational marginal pricing forecasts for each of the New England load zones as supplied by ESAI. This methodology is internally consistent and values the energy delivered into each load zone in order to generate a price score, so all projects are compared on an equal basis.

Q. Did the Distribution Companies also consider non-price factors in evaluating the reasonableness of the proposed PPAs?

A. Yes. The Distribution Companies and the DOER together formulated a "non-price evaluation criteria" consisting of five evaluation factor categories: siting and permitting; project development status and operational viability; experience and capability of bidder and project team; financing; and exceptions to the contract. Within each of these five categories there were multiple additional criteria specified for evaluation. The non-price evaluation was conducted uniformly for each submission based on the information contained in the bid and any other pertinent materials including news and press reports.

Q. Please discuss the Distribution Companies' evaluation of specific non-price items used in your evaluation.

A. The non-price evaluation assessed whether:

- The bidder has 100% control of the site.
- The bidder has developed a realistic plan for securing permits and approvals.
- The bidder and its team have experience in the development, financing and operation of similar projects.
- The project has a reasonable financial plan.
- The bidder has generally agreed with the provisions of the Model contract.

The individual scores awarded by the Distribution Companies on non-price factors is displayed in Exhibit JU-9 [CONFIDENTIAL].

Q. Do the Distribution Companies expect that the wind energy contracts will offset CO_2 emissions from other sources?

A. It is expected that wind generation, which when selected for dispatch will be base load units, will displace generation from fossil fuel facilities which for the vast majority of time in New England are marginal units on the system. Based on the forecasted production from all six projects, and that the energy output will displace gas generation on the margin, CO_2 emissions will be reduced by an estimated 9.6 million tons cumulatively over the terms of the PPAs.

In addition to the overall environmental benefits associated with the displacement of carbon emissions described above, customers will also benefit from the fact that the contracts will assist the Commonwealth in meeting the emissions reductions objectives of the Global Warming Solutions Act.

Q. Are there any other benefits to these PPAs?

A. Yes. There are a number of key areas of the contracts in which each project is responsible for the management of risk, versus transferring that risk to the Distribution Companies' customers. These include eligibility for tax credits, qualification of RECs and the variability of the output of the facility.

Q. Do the Distribution Companies' customers bear any risk of price increases if these projects fail to qualify for tax credits?

A. No, the seller is responsible for qualification of their project to obtain tax credits. Thus there is no adjustment to the contract price if they fail to do so.

Q. If any facility fails to qualify as a Class I resource, are the Distribution Companies' customers still obligated to pay for the RECs?

A. No. The Distribution Companies have no obligation under the PPAs to purchase RECs from any facility should the RECs no longer conform to the eligibility criteria of the RPS program regarding Class I RECs. However, the seller is required to use commercially reasonable efforts to maintain the facility's qualification as a renewable resource.

Q. Is there any obligation on the part of the Distribution Companies' customers if any facility fails to generate energy or RECs?

A. No. The agreements obligate the Distribution Companies to purchase the designated products generated by each facility on an "as delivered" basis up to the contract maximum amount. There is no obligation to purchase any products in excess of the contract maximum or make any additional payments in the event the plant operates below contract maximum or does not operate at all.

Q. How does the approval of PPAs covering each project facilitate the financing of renewable energy generation?

A. For the Passamaquoddy and the Peskotmuhkati projects the developer, Exergy Development, has stated in their bid submission that long term financing partners are in place but their commitment to provide financing is contingent upon obtaining a long-term power sales agreement.

For the Oakfield and the Bingham projects, the developer, First Wind, has stated in their bid submissions that executed financial arrangements by lenders hinge upon a long-term revenue commitment, such as a PPA resulting from this RFP.

For the Fletcher Mountain and Wild Meadows projects the developer, Iberdrola Renewables, typically finances renewable energy projects on-balance sheet but will consider external financing options as well. Each year Iberdrola has a number of projects in its pipeline that are in advanced development and ready for construction, and Iberdrola must choose which project to advance. Projects with executed long-term PPAs rise to the top of the list of projects to which Iberdrola will allocate limited financing to enable projects with signed PPAs to go to construction.

Q. Are there other conditions necessary to make these projects financeable?

A. Yes. We understand that the economics on each of the projects depends in part on its ability to qualify for certain tax credits, which require that the developers make certain financial commitments before the end of the year. The developers likely need some level of comfort that these PPAs will be approved before they will be willing to make those commitments. Therefore, timely and expeditious approval of these long-term PPAs is vitally important.

Q. How does each of the six proposed projects create additional employment or otherwise advance economic development?

A. For the Passamaquoddy and the Peskotmuhkati projects the developer, Exergy Development, has stated in its bid submission that each of its projects will produce approximately 100 jobs during construction and 2 full time local jobs for operation and maintenance of the plants.

First Wind has stated in its bid submissions that the Oakfield project would produce approximately 223 jobs during construction and 6-10 jobs during operations. The Bingham project will produce approximately 215 jobs during construction and 10-15 jobs during operations.

Iberdrola estimated in its bid submission that the Fletcher Mountain project would produce approximately 120 jobs during construction and 6 jobs during operations. Wild Meadows will produce 125 jobs during construction and 5-6 jobs during operations.

Q. Overall, how will each project yield contracts that are a low cost, cost-effective mechanism for procuring renewable energy on a long-term basis?

A. Because the projects selected are the top projects after evaluation of all bids received in the competitive solicitation process, each PPA constitutes a least-cost alternative for this type of renewable power purchase that the Distribution Companies can currently obtain.

Q. Are the Distribution Companies proposing to collect remuneration relating to the procurement of these PPAs?

A. Yes, consistent with the provisions of Section 83A and the Department's regulations, each Distribution Company is proposing to be remunerated for 2.75 percent of the annual payments under the PPAs covering the six proposed projects. The Department's approval of that remuneration is a condition under each PPA to an acceptable regulatory approval that would enable a project to move forward. Each Distribution Company has also submitted separate testimony which includes this calculation as a component of each Company's respective long-term renewable contract cost recovery tariff provisions.

V. SALE OF GENERATION FACILITY OUTPUT

Q. How does each Company plan to use the renewable energy procured through the proposed PPAs?

A. All four Distribution Companies intend to sell the renewable energy procured through the proposed PPAs. National Grid, NSTAR, WMECO and Fitchburg intend to sell the energy through the ISO-NE Real Time (spot) Energy Market. The difference between the spot market revenues and the contract costs will be credited to or charged to each Distribution Company's distribution customers. Each Company's renewable contract cost recovery tariff provisions will allocate all costs and revenues associated with entering into these contracts to all distribution customers and is discussed further in separate testimony.

Q. How will each Distribution Company use the RECs procured by these PPAs?

A. National Grid, NSTAR Electric and Fitchburg intend to use the RECs procured by the PPAs to satisfy their RPS obligations associated with the provision of Basic Service. Pursuant to 225 C.M.R. § 14.07, each Distribution Company is required to procure Class I RECs for eight percent of its supply for calendar year 2013, escalating annually by one percent thereafter to a maximum of 15 percent by 2020. The RECs being purchased under the contracts will assist National Grid, NSTAR Electric and Fitchburg in meeting this RPS obligation on a long-term basis.

Particularly since these are long-term contracts, National Grid, NSTAR Electric and Fitchburg recognize and want to point out that should the level of competitive retail supply activity increase, this would reduce Basic Service supply requirements and the associated RPS obligations. To the extent that RPS obligations for Class I RECs fall below the aggregate level of Class I RECs purchased under Section 83 and Section 83A contracts, National Grid, NSTAR Electric and Fitchburg would sell any excess RECs into the market. National Grid, NSTAR Electric and Fitchburg will charge Basic Service customers for the RECs obtained under the PPAs at a periodic market price (i.e., the market price determined by each Company to obtain RECs as needed to satisfy the RPS requirements and credit all distribution customers that market price (or the market price received for RECs sold into the market), thus offsetting the total costs of the PPAs.

WMECO does not anticipate a need for the RECs to meet RPS obligations. Thus, WMECO proposes to sell the RECs obtained under the PPAs, with the proceeds applied to distribution customers to reduce the net cost of the PPAs.

Q. How do the Companies propose to recover the costs associated with these transactions?

A. As noted previously, to the extent a Company chooses to sell the energy into the wholesale electricity spot market and the RECs through a competitive bid process, the Department's regulations at 220 C.MR. § 21.06 require the Company to: (1) calculate the net cost of payments made under the long-term contracts against the proceeds obtained from the sale of energy and/or RECs; (2) credit or charge all distribution customers the difference between the contract payments and proceeds through a uniform, fully-reconciling annual factor in distribution rates, subject to review and approval by the Department; and (3) design a reconciliation process that allows the Company to recover all costs incurred under such contracts, subject to review and approval by the Department.

As noted above, National Grid, NSTAR and Fitchburg intend to sell the energy into the wholesale spot market and retain the RECs to support its Basic Service RPS requirements. Accordingly, National Grid, NSTAR and Fitchburg are making this proposal under 220 C.M.R. § 21.06(1)(c) as an alternative approach subject to review and approval of the Department. Mr. Richard Chin's testimony describes NSTAR's and WMECO's cost-recovery proposal in greater detail; Mr. Scott M. McCabe's testimony describes National Grid's cost-recovery proposal in detail; and Mr. Robert Furino's separate individual testimony addresses Fitchburg's process.

Q. Does this conclude your testimony?

A. Yes, it does.

REQUEST FOR PROPOSALS

FOR

LONG-TERM CONTRACTS FOR RENEWABLE ENERGY PROJECTS

Issuance Date: April 1, 2013

Distribution Companies:

Fitchburg Gas & Electric Light Company d/b/a Unitil
Massachusetts Electric Company d/b/a National Grid
Nantucket Electric Company d/b/a National Grid
NSTAR Electric Company
Western Massachusetts Electric Company

Massachusetts Department of Energy Resources

Table of Contents

I. Introduction and Overview

1.1 Purpose of the Request for Proposals ("RFP")

Fitchburg Gas & Electric Light Company d/b/a Unitil ("Unitil"), Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid"), NSTAR Electric Company and Western Massachusetts Electric Company ("Northeast Utilities Companies"), as investor-owned electric distribution companies (collectively, "Distribution Companies" and each a "Distribution Company") serving customers in the Commonwealth of Massachusetts, in coordination with the Massachusetts Department of Energy Resources ("DOER"), are collectively seeking proposals for the supply of electric energy and/or Renewable Energy Certificates ("RECs") from renewable energy projects under long-term power purchase agreements ("PPAs" and individually a "PPA") pursuant to Section 83A of the Green Communities Act as added by chapter 209 of the Acts of 2012, *An Act relative to competitively priced electricity in the Commonwealth* (the "Act"). In this Request for Proposals ("RFP"), the Distribution Companies are soliciting energy and RECs for approximately 1.8% of their annual load (approximately 850,000 MWh) to be procured pursuant to PPAs with a duration of 10-20 years. The terms of the PPAs will be finalized between the Distribution Companies and successful bidders based on the bids submitted and selected in accordance with the process set forth in this RFP.[1] This RFP includes a draft Power Purchase Agreement ("Draft PPA"), detailing the terms by which the Distribution Companies would purchase energy and RECs, and which will serve as the reference point for any bidder exceptions (subject to the limitations described below).[2]

The fundamental purpose of the RFP is to satisfy the policy directives encompassed within Section 83A of the Act, which require the Distribution Companies in consultation with DOER and the Office of the Attorney General of the Commonwealth of Massachusetts ("AGO") to (1) solicit proposals from developers of renewable energy projects in a reasonable fashion, and (2) execute long-term PPAs in order to facilitate the financing of these projects. The standards and criteria set forth in this RFP are designed so that the proposals selected for contract negotiations will serve the interests of Section 83A of the Act by furthering those projects that have a strong likelihood of being financed

[1] The actual amount of electric energy and RECs to be procured under this RFP may depend on, among other factors, the Distribution Companies' assessment of the bids submitted and other commitments made by the Distribution Companies. Under Section 83A of the Act, the Distribution Companies may not purchase more than 3.6% of their annual load as a result of this RFP and one additional solicitation that must occur prior to December 31, 2016. For purposes of this RFP, 3.6% of distribution company load for each of the Distribution Companies based on 2011 data is as follows:

- National Grid: 779,942 MWh/year
- NSTAR Electric Company: 771,302 MWh/year
- Unitil: 17,201 MWh/year
- Western Massachusetts Electric Company: 131,432 MWh/year

[2] As noted in Appendix C, the Draft PPA is intended to provide a general description of the terms that the Distribution Companies are willing to agree to. Each Distribution Company may have other or different requirements, which are identified in the Draft PPA, and the Distribution Companies reserve the right to negotiate individually the final PPA terms with any successful bidder.

and constructed and that will provide a low cost source of long-term renewable energy supply to the Commonwealth.

The schedule for this RFP is designed to provide the potential for successful bidders to obtain an executed PPA pursuant to this RFP later this year in order that they may take advantage of the federal production tax credit or investment tax credit which, under current law and for certain technologies, requires commencement of construction on or before December 31, 2013. The Distribution Companies can offer no assurance that any particular schedule will be observed or that any particular project will otherwise qualify for any tax credit or other subsidy.

In addition to the statutory requirements set forth in Section 83A of the Act, the Distribution Companies are issuing this RFP in accordance with regulations promulgated under the Act by the Massachusetts Department of Public Utilities ("MDPU"). This RFP outlines the process that the Distribution Companies plan to follow to satisfy their obligations regarding solicitations required under Section 83A of the Act and applicable regulations; sets forth timetables regarding the solicitation process; provides information and instructions to prospective bidders; and describes the bid-evaluation process that will be followed once bids are received.

1.2 The Framework Established Pursuant to Section 83A of the Act

Section 83A of the Act requires the Distribution Companies jointly to solicit proposals from renewable energy developers in coordination with DOER at least twice during a four-year period commencing on January 1, 2013. The Distribution Companies are not permitted to enter into long-term PPAs under Section 83A, to the extent that, in the aggregate, the contract volumes would exceed four percent (4%) of the total energy demand from all distribution customers in the service territory of the Distribution Company unless they voluntarily do so, with the approval of the MDPU. Section 83A of the Act reserves ten percent (10%) of that amount, or 0.4% of demand, for the output of newly developed small, emerging or diverse renewable energy distributed generation facilities that each Distribution Company will solicit in a separate process. Assuming that reasonable proposals that conform to the requirements stated in this RFP have been received, each Distribution Company is required to enter into cost-effective long-term PPAs to facilitate the financing of renewable energy generation. The Distribution Companies are required to develop a timetable and method for solicitation and execution of long-term PPAs under Section 83A of the Act in consultation with DOER and (with respect to the method of solicitation, but not the timetable) the AGO, and subject to review and approval by the MDPU.

The long-term contracting obligation established by Section 83A of the Act is separate and distinct from the Distribution Companies' obligation to meet applicable annual renewable portfolio standards ("RPS") requirements pursuant to Section 11F of Chapter 25A of the General Laws. However, under Section 83A of the Act, the renewable-generation resource from which energy and/or RECs are procured under a long-term PPA must be eligible to participate in the RPS program and to sell RECs under the program, and a Distribution Company may use RECs purchased under such a long-term PPA to satisfy its RPS requirements.

Long-term PPAs are defined within Section 83A of the Act as PPAs having a term of 10 to 20 years. A Distribution Company may decline to consider PPA proposals having terms and conditions that it determines would require the PPA obligation to place an unreasonable burden on the company's balance sheet. All proposed PPAs are subject to the review and approval of the MDPU before becoming effective.

Consistent with the directives set forth in Section 83A of the Act, the MDPU on March 1, 2013 in D.P.U. 13-42 adopted emergency regulations at 220 CMR 21.00 *et seq*. The emergency regulations are effective upon filing and the MDPU must adopt final regulations by June 1, 2013.

As part of its approval process, the MDPU must take into consideration the AGO's recommendations, which must be submitted to the MDPU within 45 days following the filing of a proposed PPA with the MDPU. Section 83A of the Act provides that the MDPU "… shall consider both the potential costs and benefits of such contracts and shall approve a contract only upon a finding that it is a cost effective mechanism for procuring low cost renewable energy on a long-term basis taking into account the factors outlined in this section."

1.3 Procurement by Distribution Companies in Consultation with DOER

The Distribution Companies, DOER and the AGO have agreed to collaborate on a DOER-coordinated process with respect to this solicitation required under Section 83A. As a result of this collaborative process, the Distribution Companies, in consultation with DOER, have agreed to jointly issue this RFP, including associated bid forms and a Draft PPA. The purpose of this approach is to provide prospective bidders with bid submittal and evaluation requirements in order to facilitate the bidding process. Responses to the RFP will be returned to the Distribution Companies for joint evaluation and selection consistent with the terms of the RFP. Bidders shall submit proposals contemporaneously to all of the Distribution Companies.

The Distribution Companies will have the responsibility for bid selection, PPA negotiations and PPA execution. More specifically, the Distribution Companies will be responsible for the joint evaluation of the bids pursuant to the evaluation criteria set forth in the RFP and for joint bid selection. The Distribution Companies expect to coordinate their negotiation of the PPAs for the bids they select, and they will either jointly file the executed PPAs with the MDPU for approval before they become effective, or each Distribution Company may individually file those PPAs. In either event, the Distribution Companies anticipate that the PPAs will vary somewhat based on contracting requirements that are specific to each Distribution Company. Prior to short listing and bid selection, entering into any PPA, and filing any PPA for approval with the MDPU, the Distribution Companies will consult with DOER. At or after such time that an executed PPA is proposed to the MDPU, DOER will submit its assessment of (a) the process followed by the Distribution Companies resulting in the execution of the PPA, and (b) the merits of the particular PPA proposed for approval.

1.4 Procurement Process and Bid Evaluation Approach

The procurement process is designed to have three stages of evaluation, as described in Section 2.1 of the RFP. Initially, bids will be evaluated on the basis of whether certain eligibility and threshold requirements are satisfied. Eligibility requirements are designed to ensure that the bids under review offer the appropriate product and PPA tenor from qualifying renewable resources. Threshold requirements are designed to ensure that proposed projects satisfy statutory criteria under Section 83A of the Act, and meet minimum standards for viability. In the second stage, bids will be evaluated in a technology-neutral manner based on specified price and non-price evaluation criteria. This portion of the bid evaluation will be quantitative in nature (i.e., a quantitative scoring system will be utilized). Projects that pass the eligibility and threshold review and are scored favorably in the second stage of the evaluation process will be placed on a short-list and advance to the final stage of the evaluation process. At this third stage of the process, further evaluation of those remaining bids will be conducted on matters pertaining to price, project viability and the extent to which the bids, individually and as a portfolio, achieve a variety of objectives, including cost effectiveness and diversity of resources, and the remaining bids will be re-ranked based on this analysis. All three stages of the evaluation process, including the pertinent criteria, are described in Section II of this RFP.

1.5 Communications Between the Soliciting Parties and Bidders

With the exception of the pre-bid conference (see Section III, Paragraph 3.1 below), all pre-bid contact with prospective bidders and other interested parties will be via the Distribution Companies' website at www.marfp.com. Links will be available for submitting questions to the Distribution Companies, and responses will be coordinated by DOER and posted on the Distribution Companies' website.

Bids will be submitted directly to the Distribution Companies at the addresses set forth in Section III, Paragraph 3.5 of this RFP. Each bid must be submitted to all of the Distribution Companies.

Following submission of bids, communications regarding specific bids will be between the Distribution Companies and the bidder. It will be the responsibility of the bidders to keep the Distribution Companies informed about the details of their projects, such as status in obtaining permits and financing, but communications shall not include revisions to bids, except with respect to those projects that are placed on the short list and provided with an opportunity to improve their pricing, as described in Section 2.4. A bidder will be responsible for providing information submitted to one Distribution Company (in response to an information request or request for clarification) to the other Distribution Companies.

1.6 RFP Process

The timeline for the bidding process following the issuance of this RFP, as well as the schedule for other steps in the process including approval by the MDPU, is set forth below at Section 3.1.

1.7 Bidder Certification

An authorized officer or other authorized representative of a bidder certifies by its submission of its bid that: the bidder has reviewed this RFP and all attachments and has investigated and informed itself with respect to all matters pertinent to this RFP and its proposal; the bidder's proposal is submitted in compliance with all applicable federal, state and local laws and regulations, including antitrust and anti-corruption laws; and the bidder is bidding independently and that it has no knowledge of the substance of any proposal being submitted by another party in response to this RFP other than a response submitted by the bidder's affiliate, which must be disclosed in writing to the Distribution Companies with each affiliated bidder's proposal. Violation of any of the above requirements may be reported to the appropriate government authorities and will disqualify the bidder from the RFP process.

II. Bid Evaluation and Selection Criteria and Process

2.1 Overview of Bid Evaluation and Selection Process

Once bids are received by the Distribution Companies, the proposals will be subject to a consistent and defined review, evaluation and short-list selection process. The first stage consists of a review of whether the bids satisfy specified eligibility, threshold and other minimum requirements set forth in Section 2.2 of this RFP. The second stage consists of a combined price and non-price evaluation of bids that pass the first stage review, as described in Section 2.3 of this RFP. Bids that are selected for further review will enter a final stage of review which will involve additional risk assessment and consideration of the bids from a portfolio perspective consistent with the criteria set forth in Section 2.4 of this RFP. The selection of the short list will be made jointly by the Distribution Companies.

Subsequent to the selection of the short list, the Distribution Companies will be responsible for the conduct of additional evaluation and selection of bids for contract negotiations. Under Section 83A of the Act, if the Distribution Companies are unable to agree on the selection of bids among themselves, the AGO, in consultation with DOER and the MDPU, shall make the final binding determination of the winning bid(s). This post-short list selection stage of the process is described in Section 2.5 of this RFP.

2.2 Eligibility, Threshold and Other Minimum Requirements—Stage One of the Evaluation Process

2.2.1 Introduction

In order for a bid to qualify for detailed evaluation, it must satisfy certain requirements pursuant to this RFP. These requirements pertain to eligibility, a variety of threshold requirements and other requirements pertaining to participation in this RFP, including bidder certifications and allowable pricing. Following receipt of the bids, the bids will be reviewed to determine whether they satisfy these minimum requirements. Bids that do not satisfy these Stage One requirements may be disqualified from further review and evaluation.[3] Stage One requirements are set forth in the following section of this RFP.

[3] The Distribution Companies may conduct additional evaluation on bids at their discretion before the Stage One evaluation is completed.

2.2.2 Eligibility Requirements

All proposals must meet the following eligibility requirements set forth below. Specifically, proposals will be considered from an Eligible Bidder with respect to Eligible Products generated from an Eligible Facility. The Eligible Products must be offered over the Allowable Contract Term in quantities that are equal or greater than the Minimum Contract Size. Failure to meet any of these requirements could lead to disqualification of the proposal from further review and evaluation.

2.2.2.1 Eligible Bidder

An Eligible Bidder is the owner of an Eligible Facility or the development rights to an Eligible Facility, i.e., the developer of the Eligible Facility.

2.2.2.2 Eligible Facility

An Eligible Facility must be an electric generation facility that satisfies each of the following standards:

a. The electric generation facility must qualify as a RPS Class 1 Renewable Generation Unit under DOER's Class 1 Renewable Energy Portfolio Standard regulations, 225 CMR 14.01, *et seq*, and to sell RECs under the RPS Program, including the provisions of 225 CMR 14.05(5) (Special Provisions for a Generation Unit Located in a Control Area Adjacent to the ISO-NE Control Area) for facilities that are not located in the control area administered by ISO New England Inc. ("ISO-NE").

b. The generation facility must have a commercial operation date, as verified by DOER, on or after January 1, 2013 or be either a capacity expansion of an existing generation facility or a repowering of an existing generation facility that was not previously a RPS Class 1 Renewable Generation Unit, where the capacity expansion or repowering has a commercial operation date, as verified by DOER, on or after January 1, 2013. With respect to a capacity expansion or repowering of an existing generating unit, only the energy and RECs associated with the incremental capacity resulting from that expansion or repowering will be eligible for a response to this RFP.

c. The generation facility must not participate in DOER's Net Metering Program or the net metering program of any other jurisdiction.

2.2.2.3 Eligible Products

An Eligible Bidder must propose separate prices to sell (i) electric energy, (ii) RECs and (iii) bundled electric energy and RECs from an Eligible Facility under a PPA. The structure of the contract will be both unit-specific and unit-contingent. Any RECs sold under a PPA will only be purchased by the applicable Distribution Company to the extent that those RECs conform to the eligibility criteria for a RPS Class 1 Renewable Generation Unit under DOER's Class 1 Renewable Energy Portfolio Standard regulations, 225 CMR 14.01, *et seq*. If a Distribution Company agrees to purchase both electric energy and RECs under a PPA and the RECs cease to conform to the RPS Class I eligibility criteria, the applicable Distribution Company will thereafter only purchase electric energy under that PPA, and the Seller will be permitted to sell those non-conforming RECs to a third party. Solar renewable energy certificates that are eligible under DOER's Solar Carve-Out Program will not be considered eligible products under this solicitation.

The Draft PPA (attached as Appendix C to this RFP) contains terms for the sale of both electric energy and RECs, although the purchase and sale under a particular PPA may be only for energy or only for RECs, rather than for both energy and RECs. The Distribution Companies will not purchase capacity under any PPA that results from this RFP process.

2.2.2.4 Allowable Contract Term

Consistent with Section 83A of the Act, an Eligible Bidder may submit a proposal for the sale of Eligible Products from an Eligible Facility for a term of 10 to 20 years. The bidder must submit two proposals for contract term lengths five years apart. Both proposals must conform to the allowable contract term of 10 to 20 years and will be evaluated as set forth in Section 2.3.1 of this RFP.

2.2.2.5 Minimum Contract Size

The minimum net generating capability of an Eligible Facility is one (1) MW.[4] A bidder may bid the entire production of energy and/or RECs from its proposed Eligible Facility, or any portion of the production for its proposed Eligible Facility, provided that if a bidder only bids a portion of the production from its proposed Eligible Facility, the pro rata portion of that production must be equivalent to at least one (1) MW (e.g., if a bidder bids one-third of the production from its Eligible Facility, the generating capability of that Eligible Facility must be at least three (3) MW). Under this RFP, there is not a maximum contract size *per se*, but bidders are reminded that the Distribution Companies intend to procure not more than 1.8% of their respective distribution loads in this RFP process.

2.2.3 Threshold Requirements

2.2.3.1 Introduction

Bids that meet all the Eligibility Requirements will be evaluated to determine compliance with threshold requirements, which have been designed to screen out proposals that are insufficiently mature from a project development perspective; lack technical viability; impose unacceptable financial accounting consequences for the Distribution Companies; do not satisfy the minimum requirements set forth in Section 83A of the Act; are not in compliance with RFP requirements

[4] Section 83A of the Act provides for a separate solicitation process for small, emerging or diverse renewable energy distributed generation facilities.

pertaining to credit support; or fail to satisfy minimum standards for bidder experience and ability to finance the proposed project. The threshold requirements for this RFP are set forth below.

2.2.3.2 Reasonable Project Schedule

Absent other compelling circumstances, the Distribution Companies are interested in projects that can demonstrate the ability to develop, permit, finance, and construct the proposed Eligible Facility within a reasonably proximate time. To that end, Eligible Bidders must either:

(i) provide a reasonable schedule that provides for closing of construction financing and commencement of construction on or by December 31, 2015 and a commercial operation date on or by December 31, 2016; or

(ii) provide an alternative reasonable schedule for a later closing of construction financing and commencement of construction and for a later commercial operation date, not later than December 31, 2018, and explain why those later dates are appropriate for the Eligible Facility.

A proposal that does not have a reasonable schedule that provides sufficient time for the application for, and receipt of, necessary permits and approvals may be determined not to have satisfied this threshold requirement. In addition, a proposal that is determined to have a "fatal flaw" such that it will be unable to obtain permits or property rights necessary to finance and construct the proposed project may be determined not to have satisfied this threshold requirement.

2.2.3.3 Site Control

The bidder must demonstrate that it has control or a right to acquire control over a site for its proposed project. To meet this threshold requirement, bidders must either provide documentation showing that they own the site or have a lease with respect to the site on which the proposed project will be located; have an option agreement to purchase or lease the site, or at a minimum have negotiated a letter of intent for control of the site. Bidders that only have a letter of intent for the site at the time of bid submission may be required to obtain a binding site control agreement at a later time prior to execution of a PPA (which may include an option to purchase or an option to lease). Site control for offshore wind projects or projects on state lands will be evaluated based on the particular submissions of bidders and the extent to which they can demonstrate a high likelihood that they will be able to obtain the necessary rights to construct and operate the proposed project, including the real property rights associated with the interconnecting facilities from the proposed project to the transmission grid or local distribution facilities. A similar showing will be required with respect to new transmission projects.

2.2.3.4 Technical Viability; Ability to Finance the Proposed Project

The bidder must demonstrate that the technology it proposes to use is technically viable and that the bidder has the ability to finance the proposed project. Technical viability may be demonstrated by showing that the technology is commercially available and has been used successfully. If a bidder plans to use technology that is not commercially proven, it must provide evidence of technical viability and a credible plan to finance the project in light of the state of development of the technology. The bidder must provide a reasonable plan for financing the proposed project, including the funding of development costs and the required development period security and the ability to acquire the required equipment in the time frame proposed. If the proposed Facility is dependent on the construction of a new transmission project, the bidder shall provide a reasonable plan for financing the proposed transmission project.

2.2.3.5 Experience

The bidder must demonstrate that it has a sufficient amount of relevant experience to successfully develop, finance, construct and operate its proposed project. This demonstration can be made by showing that bidder (or a substantial member of bidder's development team) has:

a. Successfully developed a similar type of project; OR
b. Successfully developed one or more projects of different technologies but of similar size or complexity or requiring similar skill sets; AND
c. Experience in financing power generation projects.

If the proposed facility is dependent on the construction of a new transmission project, the bidder shall demonstrate that the sponsors of the transmission project have the requisite experience.

2.2.3.6 Contribution to Electricity Reliability Within Massachusetts

One of the criteria for approval of a long-term contract by the MDPU under Section 83A of the Act is that the proposed generation project must "provide enhanced electricity reliability within the commonwealth." This threshold requirement can be satisfied by bidder's agreement to commit any qualifying capacity to ISO-NE exclusively. Bidders may provide other demonstrations which will be considered in determining whether this threshold requirement is satisfied.

2.2.3.7 Contribution to Moderating System Peak Load Requirements

Another criterion under Section 83A of the Act is that a proposed project must "contribute to moderating system peak load requirements." This threshold requirement can be satisfied by bidder's demonstration of projected energy output during the peak hours of ISO-NE's summer and/or winter peak periods. For purposes of this RFP, these hours are 1 pm through 6 pm for the months of June through September (summer period) and 5 pm through 7 pm for the months of October through May (winter period).[5]

[5] These are the hours used in ISO New England's Forward Capacity Market for determining Qualified Capacity for Intermittent Resources.

2.2.3.8 Contribution to Employment; Economic Development Benefits

Another criterion under Section 83A of the Act is that a proposed project create additional employment and economic development in Massachusetts, where feasible. This threshold requirement can be satisfied by a showing of:

a. Direct employment benefits associated with the proposed project;

b. Indirect employment benefits associated with the proposed project; or

c. Other economic development benefits associated with the proposed project.

The Distribution Companies will consider a broad range of other economic development benefits that could be achieved by a proposed project, including (solely by way of example) creating property tax revenues, and the provision of renewable energy at a lower costs than other potential projects.

2.2.3.9 Security Requirements

Bidders will be required to post Development Period Security and Operating Period Security. The required levels of Development Period Security are the Per kWh per hour Development Period Security Amount multiplied by the Contract Maximum Amount in kWh per hour For projects that have projected capacity factors of 50% or more, the Per kWh per hour Development Period Security Amount is $30; for projects that have projected capacity factors of less than 50% but more than 20%, the Per kWh per hour Development Period Security is $20; for projects that have projected capacity factors of 20% or less, the Per kWh per hour Development Period Security is $10. Fifty percent (50%) of the Development Period Security must be provided upon execution of the PPA. The remaining fifty percent (50%) of the Development Period Security must be provided upon MDPU approval of the PPA. Development Period Security will be promptly returned if the MDPU does not approve the PPA. Once a project achieves Commercial Operation, the amount of required security (Operating Period Security) will be the same as the required amount of Development Period Security.

The required security must be in the form of a cash deposit or a letter of credit, except that for Operating Period Security, individual Distribution Companies may be willing to accept alternative forms of security for part or all of the required security, such as a corporate guarantee from an entity with a credit rating of BBB or better from Standard & Poor's or Baa2 or better from Moody's Financial Services.

2.2.3.10 Unreasonable Balance Sheet Impacts

Section 83A of the Act provides that a Distribution Company may decline to consider contract proposals having terms and conditions that it determines would place an unreasonable burden on the Distribution Company's balance sheet. Each individual Distribution Company retains the right to make such a determination based upon its evaluation of particular proposals.

In the Response Package, bidders are required to provide information that will assist the Distribution Companies in determining whether a contract based on the proposal submitted would place an unreasonable burden on its balance sheet.[6] If a Distribution Company determines that a proposal would impose such a burden or at least a substantial risk of such a burden, it will notify the bidder in writing and will explore with the bidder and the other Distribution Companies whether the proposal and the terms of the power purchase agreement can be modified to prevent an unreasonable burden being placed on the Distribution Company's balance sheet. If after such process, the Distribution Company determines that the bidder's proposal, as it may have been modified, or the terms of the proposed agreement, places an unreasonable burden on the Distribution Company's balance sheet, it may decline to give further consideration to the proposal.

The Distribution Companies reserve the right to review contract proposals for balance sheet impacts at any time during the evaluation process. For example, a Distribution Company might only review highly ranked project proposals for their balance sheet impact.[7]

2.2.3.11 Timeliness

The bid submitted must be timely submitted in accordance with Sections 3.1 of this RFP.

2.2.3.12 Facilitate Financing of Renewable Energy Generation

The bidder must demonstrate, as a threshold matter, that its proposal advances the goal of Section 83A of the Act for the selection of cost-effective long term contracts that facilitate the financing of renewable energy generation. The bidder should specify how a PPA resulting from this RFP process would either permit it to finance a project that would otherwise not be financeable or assist it in obtaining financing of its project.

2.2.4 Other Minimum Requirements

Other RFP requirements pertain to bid certification, allowable pricing and bid completeness, as described in this section.

[6] Review of balance sheet impacts would include, but not be limited to, a Distribution Company's assessment of whether a proposal would result in the seller under the proposed PPA being a variable interest entity that would trigger consolidation of seller's finances on to the Distribution Company's balance sheet under Accounting Standards Codification (ASC) Topic 810 "Consolidation" and any other applicable or updated ASC topic.

[7] In connection with this review, a bidder, at the request of one or more Distribution Companies, may be required to provide pro forma income and cash flow statements for the term of the proposed PPA (including revenue and cost data by major categories, debt service, depreciation expense and other relevant information).

2.2.4.1 Proposal Certification

Bidders are required to provide firm pricing for 180 days from the due date for submission of proposals. The bidder must also sign the certification form in Appendix B verifying that the prices, terms and conditions of the proposal are valid for at least 180 days. An officer or duly authorized representative of the bidder is required to sign the Proposal Certification Form.

2.2.4.2 Allowable Forms of Pricing

The Distribution Companies will accept proposals from renewable resources for energy and/or RECs that conform to the following requirements:

(a) Proposals must offer one or a combination of the following pricing options:

(1) a fixed price (in \$/MWh and/or \$/REC) for the term of the contract; or

(2) a price (in \$/MWh and/or \$/REC) that increases by a fixed rate for the term of the contract (e.g. 2% increase per year); or by different fixed rates for various periods of the contract (e.g. 3% increase for the first 5 years, 2% for the next 5 years, etc.).

(b) Proposals for a bundled price for energy and RECs must allocate the total bundled price between energy and RECs, with only the energy being purchased at the stated energy price if the RECs cease to conform to the eligibility criteria for a RPS Class 1 Renewable Generation Unit under DOER's Class 1 Renewable Energy Portfolio Standard regulations, 225 CMR 14.01, *et seq*. All else being equal, a preference will be given to an allocation of the price between energy and RECs that most closely aligns with the market value of those products.

(c) Proposed prices may not be conditioned upon or subject to adjustment based upon the availability of the Federal Production Tax Credit or the Federal Investment Tax Credit or the availability or receipt of any other government grant or subsidy.

These forms of pricing are conforming under this RFP. The Distribution Companies may consider other forms of pricing as an alternative as long as the bidder submits a proposal for the project with conforming pricing as described above. Alternative pricing may be considered subject to the following conditions:

- Any index used in a pricing formula must be energy-related; and
- There must be a price cap for each year under the proposed contract.

The Distribution Companies are under no obligation to consider or accept any form of alternative pricing.

The Seller must identify a Delivery Point for electric energy, which must be at an ISO-NE Pool Transmission Facility. All costs associated with such delivery shall be borne by the Seller.

With respect to any pricing proposal, including those seeking separate cost recovery for transmission costs (as described below), payments will only be made for Products delivered to the Delivery Point and reflected in the applicable Distribution Company's account at ISO-NE (for energy) and the NEPOOL Generation Information System (for RECs).

Guidance for Bids That Seek Recovery of Transmission Costs Through FERC-Approved Tariffs Outside the PPA

Section 83A of the Act permits the bidder and a Distribution Company to propose to recover significant transmission costs associated with the Eligible Facility outside of the power purchase agreement. This alternative would allow the bidder (or transmission provider as applicable) to recover the costs of constructing, owning, and maintaining certain transmission facilities through federal transmission rates, so long as the MDPU finds that recovery to be in the public interest. Under this alternative bidding scenario, the transmission costs associated with transmission facilities required to deliver electric energy from the Eligible Facility to the Delivery Point would not be included in the prices charged under power purchase agreement, but rather those costs would be recovered from Massachusetts customers through the transmission tariffs required to be filed with and accepted by FERC pursuant to the provisions of the Federal Power Act. This feature is unique, and the intention is to align any such proposal with the public policy reflected in the Federal Energy Regulatory Commission's Order 1000.

The bidder choosing to propose this alternative must provide schedules that estimate the total construction cost of the transmission facilities and the annual revenue requirement of the transmission facilities through the period over which the underlying capital costs are proposed to be recovered (which may be longer than the term of the PPA), including cost of capital and all other elements of costs traditionally considered in cost-of-service ratemaking. The bidder must also include a cap on both the total construction cost of the transmission facilities and the annual revenue requirement that the transmission provider would be allowed to recover through federal transmission rates, and the evaluation of the overall price of a proposal including this feature would be based on that proposed annual revenue cap. The proposed annual revenue cap must be based on the amount of the capped construction cost (i.e., the proposal should not assume another generating facility will be constructed in the future and will use the same transmission facilities). Bidders proposing this alternative pricing structure are encouraged to offer price benefits to the Distribution Companies and their customers to the extent their construction costs or annual revenue requirements are less than their proposed caps.

The bidder must include in its proposal a description of the proposed transmission project. In addition, the bidder must identify (a) the sponsors of the proposed transmission facilities, (b) any affiliation or other relationship with the owners of the Eligible Facility or any of the Distribution Companies, and (c) any proposed contractual relationship between the owners of the transmission project and the Distribution Companies (other than the service agreement described below).

The PPA associated with this alternative must include provisions to implement its proposal with respect to transmission, including: (i) termination of the PPA if the total construction costs of the transmission facilities estimated in a study performed by ISO New England or another independent entity acceptable to the Distribution Companies exceeds the proposed cap for those construction costs; and (ii) termination of the PPA if the associated FERC filing seeks cost recovery in excess of the proposed annual revenue cap. The transmission provider will also be required to enter into a service agreement with the Distribution Companies that will provide that no costs for the transmission facilities will be recovered from those Distribution Companies unless and until the Eligible Facility achieves its commercial operation date. Finally, either (x) the PPA must include a reduction of the price paid if the federal transmission rates for the transmission facilities exceed the proposed annual revenue cap at any time during the term of the PPA or (y) the service agreement with the transmission provider must provide that the rates paid by the Distribution Companies will not exceed the proposed capped annual revenue requirement.

In addition, a bidder proposing an alternative to recover significant transmission costs associated with the Eligible Facility outside of the power purchase agreement must also submit a bid that contemplates recovery of all transmission costs under the power purchase agreement. Therefore, a bidder proposing this alternative must include proposed pricing that conforms to the requirements set forth above in this Section 2.2.4.2 (i) with all transmission costs recovered through payments under the PPA (and not through federal transmission rates) and (ii) with transmission costs recovered separately through federal transmission rates. Under each scenario, the bidder would remain contractually responsible if it is unable to perform under the PPA because the requisite transmission is not available or is delayed. The bidder shall specify the extent to which the transmission facilities proposed to be built, ownership of such facilities and the costs associated with the proposed Facility differs between the two pricing proposals.

2.2.4.3 Bid Completeness: Bidder Response Forms and the Draft PPA

Bidders must use the forms provided in Appendix B and provide complete responses. Appendix B contains the Bidder Response Forms which outline the information required from each bidder. Bidders are required to provide the information requested in each section of the Bidder Response Form. If any of the information requested is inconsistent with the type of technology or product proposed, the Bidder should include "N/A" and describe the basis for this designation. If a bidder does not have the information requested in the bid forms and cannot obtain access to that information prior to the bid submittal due date, the bidder should provide an appropriate explanation.

Appendix C is the form of draft Power Purchase Agreement (Draft PPA) which should be regarded as a framework for the final PPA. The final PPA will be the subject of negotiation between the Distribution Companies and each bidder. Each Distribution Company may require company-specific terms on certain PPA provisions, which will be identified in the Draft PPA, and the Distribution Companies reserve the right to negotiate PPA terms individually with a bidder. Bidders are required to review the Draft PPA and provide a red-line version of the Draft PPA with their requested changes and a detailed description of the substantive changes they propose to make, if any. The requested changes will be reviewed and considered in the context of an overall value and risk assessment associated with each proposal. If bidders do not propose to make any changes to the Draft PPA, they must so state. Bidders are discouraged from proposing material changes to the Draft PPA, and the nature and extent of any changes will be a component of the analysis of the non-price factors associated with the proposal (as noted below).

2.3 Second Stage Evaluation – Price and Non-Price Analysis

Proposals that meet the requirements of the first stage review will then be subject to an initial price and non-price analysis. The results of the price and non-price analysis will be a relative ranking and scoring of all proposals. The Distribution Companies plan to weight price factors at 80 percent (80%) and non-price factors at 20 percent (20%) for purposes of conducting the second stage evaluation.

2.3.1 Initial Evaluation Using Price-Related Evaluation Criteria

The price evaluation will be based on a comparison of (a) the total cost (on both a unitized and net present value basis) of the products bid, which may include energy and/or RECs (and, if applicable, transmission costs proposed to be recovered through FERC-approved transmission rates rather than through the proposed PPA in accordance with paragraph 2.2.4.2 of the RFP), to (b) the estimated market value of these products, taking into consideration the production profile and location of the proposed project over the term of the proposed bid, locational marginal price benefits, and discount factor equal to the load-weighted average cost of capital of the Distribution Companies (for purposes of net present value calculations). The Distribution Companies plan to use a common price forecast that will incorporate the effects of future federal regulation of carbon dioxide emissions on relevant energy prices. The metric used will be net $/MWh cost or benefit, on a net present value basis, based on a metric developed by the Distribution Companies. Subject to the discussion of transmission costs in paragraph 2.2.4.2 above, each bidder will be responsible for all costs associated with interconnecting its project to the transmission grid at its proposed Delivery Point.

Proposals will be ranked from highest to lowest net benefit (or lowest to highest net cost) on a dollars per MWh basis based on the result derived through the application of the methodology described above.

2.3.2 Initial Non-Price Evaluation

The non-price evaluation will be conducted collectively by a group of representatives of the Distribution Companies and will consist of five overall categories: (1) siting and permitting; (2) project development status and operational viability; (3) experience and capabilities of bidder and the project development team; (4) financing; and (5) exceptions to the Draft PPA. Within each category are a number of related criteria that will be considered in the evaluation. This section of the RFP will identify and describe in more detail the individual criteria within each primary category. The relative importance of each of the criteria in terms of the scoring of the bids will be developed prior to receipt of bids and will be utilized during the bid evaluation process.

2.3.2.1 Purpose of Non-Price Evaluation Criteria

The non-price evaluation criteria other than contract exceptions are designed to assess the likelihood of a project coming to fruition based on various factors critical to successful project development.

The objectives of the criteria are to provide an indication of the feasibility and viability of each project and the likelihood of meeting the proposed commercial operation date. Proposals are preferred that can demonstrate, based on the current status of project development and past experience, that the project will likely be successfully developed and operated as proposed. The purpose of contract exceptions as a non-price evaluation criterion is to assess the extent to which a bidder seeks to change the terms of the Draft PPA in a manner that is adverse to the Distribution Companies and their customers.

2.3.2.2 Factors to be Assessed in Non-Price Evaluation

Within each of the five non-price evaluation factors, a variety of project and proposal-related factors will be assessed. They are summarized as follows:

- Siting and permitting
    - Extent to which site control has been achieved, including acquisition of necessary easements or rights-of-way
    - Identification of required permits and approvals
    - Status of efforts and credibility of plan to obtain permits and approvals
    - Community relations plan
- Project development status and operational viability
    - Completeness and credibility of detailed critical path schedule; ability to meet scheduled construction start date and commercial operation date
    - Credibility of fuel resource plans or energy resource assessments
    - Reliability of proposed technology
    - Commercial access to proposed technology
    - Progress in interconnection process
    - Viability of any proposed transmission plans
- Experience and capabilities of bidder and project development team (including, where applicable the transmission development team)
    - Project development
    - Project financing
    - Operations and maintenance
    - Experience in the ISO-NE market
- Financing
    - Credibility of financing plan
    - Financial strength of project sponsors
- Exceptions to Draft PPA
    - The extent to which bidder accepts provisions of the Draft PPA
    - The extent to which bidder proposes exceptions that are adverse to the Distribution Company buyers

The non-price evaluation will be conducted in a systematic fashion. The Distribution Companies will conduct the price evaluation before they conduct the non-price evaluation, and they may elect not to conduct the non-price evaluation for any proposal that could not be successful based on the difference between its price and the price of competing proposals.

Following the total price and non-price rankings conducted in this second evaluation stage, a further review of the bids will be conducted and a short list selected. The Distribution Companies may, but are not required to, provide all bidders on this short list with an opportunity to improve the pricing in their proposals (including the allocation of any bundled pricing between electric energy and RECs) prior to the third evaluation stage. DOER will be provided with a copy of the proposals that are selected for the short list, including any improvements to the pricing in those proposals, and an explanation of the Distribution Companies' rationale for selecting those proposals for the short list.

It is expected that not all proposals will be placed on the short list and that not all proposals on the short list will be offered the opportunity to negotiate a PPA.

2.4 Third Stage Evaluation – Re-ranking of Proposals

In this third stage of the evaluation, the Distribution Companies will re-rank the proposals on the short-list based on the second stage evaluation criteria and, at their discretion, the following additional factors:

- Cost effectiveness of the bids;
- Risk associated with project viability of the bids;
- The extent to which additional employment and economic development would be created;
- Any unique risks to customers that may be associated with projects proposing to recover transmission costs through transmission rates; and
- Portfolio effect: the value of diversity of resources—by size and type of resources.

In order to provide greater assurance that the RFP will lead to successful results, DOER and the Distribution Companies believe that a third stage evaluation process that uses the second stage evaluation as a guide and provides for a reasonable degree of considered judgment based on criteria specified in this RFP is an important part of the RFP bid evaluation and selection process.

The objective of the third stage of evaluation is to select the proposal(s) which provide the greatest value consistent with the stated objectives and requirements as set forth in the RFP. Generally, DOER and the Distribution Companies prefer viable projects that provide low cost renewable energy with limited risk and some degree of resource diversity. However, the Distribution Companies recognize that any particular project may not be ranked highly with respect to all of these considerations and the extent to which the stated RFP objectives will be satisfied will depend, in large part, on the particulars of the proposals that are submitted.

Under Section 83A of the Act, if the Distribution Companies are unable to agree on the selection of bids among themselves, the AGO, in consultation with DOER and the MDPU, shall make the final binding determination of the winning bid(s).

2.5 Contract Negotiation Process

Bidders selected for negotiations by the Distribution Companies will be required to indicate in writing to the Distribution Companies whether they intend to proceed with their proposals within five business days of being notified. As previously noted, the Distribution Companies expect to coordinate their negotiation of PPAs with individual bidders, although there will be differences in the PPAs that are specific to the contracting practices of each Distribution Company. The bidders will enter into separate PPAs with each Distribution Company with which they contract.

The total energy and/or RECs included in a successful bid will be allocated among the Distribution Companies based upon their total distribution loads in Massachusetts.

2.6 Regulatory Approval

Once a Distribution Company has executed a PPA as a result of this RFP process, the Distribution Company intends to submit the proposed PPA to the MDPU for review and approval within 30 days of execution, unless circumstances require a longer period to prepare the MDPU filing materials. The Distribution Companies may elect to file their PPAs with an individual counterparty jointly instead. Any bidder requiring DPU approval of its PPA by a certain deadline must state that deadline in its proposal, and that deadline will be considered in assessing the overall viability of the bidder's project.

The PPAs filed for approval by the MDPU as a result of this RFP will be filed under Section 83A of the Act and the MDPU's applicable regulations. Section 83A, as implemented by the MDPU, establishes several requirements relating to the MDPU's review and approval. In addition, the MDPU has promulgated emergency regulations at 220 CMR 21.00 *et seq.*, setting forth the criteria for its review pursuant to the requirements of Section 83A of the Act. The MDPU's regulations must be replaced by final regulations by June 1, 2013. In addition, in evaluating a proposed PPA, the MDPU will consider the recommendations of the AGO, which must be submitted to the MDPU within 45 days of the filing of the proposed PPA.

Once the MDPU issues a decision approving a Distribution Company's request for approval of an executed PPA, the Distribution Company shall have five (5) business days to review the form and substance of the Department's approval. The Distribution Company shall have the opportunity to terminate the PPA if the MDPU's approval contains terms or conditions that are deemed to be unsatisfactory to the Distribution Company, in its sole discretion. Terms or conditions that may be unsatisfactory include but are not limited to denial of annual remuneration equal to 2.75 percent of the annual payments under the contract, which is required by Section 83A and is intended to compensate the Distribution Company for accepting the financial obligation of the long-term contract at issue.

III. Instructions to Bidders

3.1 Schedule for the Bidding Process

The proposed schedule for the bidding process is set forth in Chart 1.[8] The Soliciting Parties reserve the right to revise the schedule as necessary. Any changes to the schedule up to and including the due date for submission of bids will be posted on the website for this RFP. In addition, the Distribution Companies reserve the right to establish a schedule that is different than the one set forth in this RFP.

Chart 1
RFP Schedule

Event	Anticipated Dates
Issue RFP	April 1, 2013
Bidders Conference	April 16, 2013
Submit Notice of Intent to Bid	April 22, 2013
Deadline for Submission of Questions	April 22, 2013
Due Date for Submission of Proposals	May 6, 2013
Selection of Short-Listed Bidders	August 5, 2013
Negotiate and Execute Contracts	September 3, 2013
Submit Contracts for MDPU Approval	October 1, 2013

3.2 Bidders Conference; Bidder Questions; Notice of Intent to Bid

A Bidders Conference will be held for interested persons approximately two weeks after the final RFP document is posted on the RFP website. The purpose of the Bidders Conference is to provide the opportunity to clarify any aspects of the RFP. Prospective bidders are encouraged to submit questions about the RFP prior to the Bidders Conference. The Distribution Companies will attempt to answer questions submitted prior to and during the Bidders Conference. Although the Distribution Companies may respond orally to questions posed at the Bidders Conference, only written answers that are provided in response to written questions will be official responses.

The Distribution Companies will also accept written questions pertaining to the RFP following the Bidders Conference up to the date set forth in Chart 1. Both the questions and the written responses will be posted on the RFP website (without identifying the person who asked the question).

[8] This schedule was designed to provide the potential for successful bidders to obtain an executed PPA later this year pursuant to this RFP in order that they may take advantage of the federal production tax credit or investment credit which, under current law, requires commencement of construction on or before December 31, 2013. The Distribution Companies can offer no assurance that any particular schedule will be observed or that any particular project will otherwise qualify for any tax credit or other subsidy.

Prospective bidders are also encouraged to submit a Notice of Intent to Bid form within 21 days of issuance of the RFP. The Notice of Intent to Bid form is attached as Appendix A to the RFP. The Distribution Companies will provide any updates by email regarding the RFP to prospective bidders who submit a Notice of Intent to Bid. Persons that submit a Notice of Intent to Bid are not obligated to submit a proposal.

3.3 Preparation of Proposals

Each bidder shall have sole responsibility for carefully reviewing the RFP and all attachments and for thoroughly investigating and informing itself with respect to all matters pertinent to this RFP and its proposal, including pertinent ISO-NE tariffs and documents. Bidders should rely only on information provided in the RFP and any associated written updates when preparing their proposals. Each bidder shall be solely responsible for and shall bear all of its costs incurred in the preparation of its proposal and/or its participation in this RFP.

3.4 Submission of Proposals; Confidentiality

Bidders must submit one original ring-bound copy of their entire proposal as well as one CD with the entire contents of the proposal to the Official Contact for each Distribution Company that is intended to be the recipient of a proposal. Bids must be submitted by noon eastern prevailing time on the due date for proposals set forth in Section 3.1. Fax or email submissions will not be accepted. The Distribution Companies reserve the right to reject any proposals received after the deadline.

Each proposal shall contain the full name and business address of the bidder and bidder's contact person and shall be signed by an authorized officer of the bidder. Bidders may sign the original proposal and include copies of the signature page with the remaining proposals.

Bidders must clearly identify all confidential information in their Proposals. However, bidders should take care to designate as confidential only those portions of their Proposals that genuinely warrant confidential treatment. The practice of marking each and every page of a Proposal as "confidential" is discouraged.

The Distribution Companies agree that they shall use commercially reasonable efforts to treat the non-public information they receive from bidders in a confidential manner and to not, except as required by law or in a regulatory proceeding, disclose such information to any third party or use such information for any purpose other than in connection with this RFP; provided, that, in any regulatory, administrative or judicial proceeding in which confidential information is sought, the Distribution Companies shall take reasonable steps to limit disclosure and use of said confidential information through the use of non-disclosure agreements or orders seeking protective treatment, and shall inform the bidders if confidential information is being sought. Notwithstanding the foregoing, in any regulatory proceeding in which such confidential information is sought and a request for confidential treatment is made to the MDPU, the Distribution Companies shall not be responsible in the event that it is determined that the request for treating information in a confidential manner is not warranted. The bidders shall be required to use commercially reasonable efforts to treat all information received from the Distribution Companies in a confidential manner and will not, except as required by law or in a regulatory proceeding, disclose such information to any third party. The Distribution Companies reserve the right to share confidential information with DOER and the AGO with respect to submitted bids to facilitate DOER's and the AGO's ability to perform their roles under Section 83A, including conducting an assessment of (a) the process followed by the Distribution Companies and (b) the merits of one or more PPAs proposed for approval to the MDPU.

Bidders should be aware that, under recent decisions issued by the MDPU, confidential price and price-related terms and conditions may be disclosed during the MDPU approval process to parties granted intervenor status in the proceeding. In past proceedings, intervenor status has been granted to competitive suppliers and industry trade groups, and therefore, confidential price information has been required to be disclosed to legal counsel and/or a third-party consultant retained by the intervenor for purposes of the proceeding.

Confidential pricing information relating to the bid submissions and in the possession of DOER or the AGO from time to time is not subject to public disclosure. Under G.L. c. 4, § 7(26)(g), DOER and the AGO retain statutory authority to protect trade secrets or commercial or financial information. Additionally, under G.L. c. 25A, §7 DOER has statutory authority to protect price, inventory and product delivery data.

3.5 Official Contact for the RFP

All copies of the proposal should be sent to the attention of the Official Contact for the Distribution Companies at the addresses listed below:

Fitchburg Gas & Electric Light Company d/b/a Unitil:
Robert S. Furino
Director, Energy Contracts
Unitil Service Corp.
6 Liberty Lane
Hampton, NH 03842-1720
Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid:
Corinne Abrams
Manager, Environmental Transactions
Energy Procurement
National Grid
100 East Old Country Road
Hicksville, NY 11801

NSTAR Electric Company and
Western Massachusetts Electric Company:
Jeffery Waltman
Manager, Planning and Power Supply
NSTAR Electric & Gas Corp.
One NSTAR Way, SUMNE220
Westwood, MA 02090-9230

Any questions regarding the RFP should be sent to:

Robert S. Furino, furino@unitil.com
Corinne Abrams, Corinne.Abrams@nationalgrid.com
Jeffery Waltman, Jeffery.Waltman@nstar.com

3.6 Organization of the Proposal

Bidders are required to organize their proposal consistent with the contents of the Response Package in Appendix B. The organization and contents of the proposal should be organized as follows:

1. Certification, Project and Pricing Data
2. Executive Summary
3. Transmission Pricing Information and Other Relevant Information for Proposals Seeking to Recover Transmission Costs Through Federal Transmission Rates
4. Additional Operational Parameters
5. Energy Resource Plan
6. Financial/Legal
7. Siting and Interconnection
8. Environmental Assessment and Permit Acquisition Plan
9. Engineering and Technology; Commercial Access to Equipment; Contribution to Employment and Economic Development
10. Operation and Maintenance
11. Project Schedule
12. Project Management/Experience
13. Alternatives
14. Exceptions to Draft PPA

3.7 Modification or Cancellation of the RFP and Solicitation Process

Following the submission of bids, the Distribution Companies may request additional information from bidders at any time during the process. Bidders that are not responsive to such information requests may be eliminated from further consideration. Unless otherwise prohibited, the Distribution Companies may, at any time up to final award, postpone, withdraw and/or cancel this RFP; alter, extend or cancel any due date; and/or, alter, amend, withdraw and/or cancel any requirement, term or condition of this RFP, any and all of which shall be without any liability to DOER, the AGO and the Distribution Companies.

By submitting a bid, a bidder agrees that the sole recourse that it may have with respect to the conduct of this RFP is by submission of a complaint or similar filing to the MDPU in a relevant docket pertaining to this RFP.

DRAFT*

POWER PURCHASE AGREEMENT

BETWEEN

**[FITCHBURG GAS AND ELECTRIC LIGHT COMPANY, D/B/A UNITIL]
[MASSACHUSETTS ELECTRIC COMPANY AND
NANTUCKET ELECTRIC COMPANY, D/B/A NATIONAL GRID]
[NSTAR ELECTRIC COMPANY]
[WESTERN MASSACHUSETTS ELECTRIC COMPANY]**

AND

**[_________________]
[Seller]**

As of [___________], 2013

*This draft Power Purchase Agreement is intended to provide a general description of the terms that the Massachusetts electric distribution companies are willing to agree to. The final Agreement will be subject to negotiations with the individual electric distribution companies. Accordingly, certain provisions in the final Agreement may differ from this draft Agreement. In addition, bidders proposing to recover significant transmission costs through federal transmission rates must include in their mark-up the additional material described in Section 2.2.4.2 of the RFP.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS (CONT.)

Page

TABLE OF CONTENTS (CONT.)

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT (as amended from time to time in accordance with the terms hereof, this **"Agreement"**) is entered into as of [_________], 2013 (the **"Effective Date"**), by and between [Fitchburg Gas and Electric Light Company, d/b/a Unitil, a Massachusetts corporation] [Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid, a Massachusetts corporation] [NSTAR Electric Company, a Massachusetts corporation] [Western Massachusetts Electric Company, a Massachusetts corporation] (**"Buyer"**), and [________________], a [__________________] (**"Seller"**). Buyer and Seller are individually referred to herein as a **"Party"** and are collectively referred to herein as the **"Parties"**.

WHEREAS, Seller is developing the [_______] electric generation facility to be located in [________],which is more fully described in Exhibit A hereto (the **"Facility"**), which shall qualify as a RPS Class I Renewable Generation Unit and which is expected to be in commercial operation by [_______]; and

WHEREAS, Buyer is required under Section 83 of the Massachusetts Green Communities Act to enter into certain long-term contracts for the purchase of energy and/or renewable energy certificates from renewable generators meeting the requirements of that statute; and

WHEREAS, Buyer and Seller desire to enter into this Agreement whereby Buyer shall purchase from Seller certain [Energy and/or RECs] (each as defined herein) generated by or associated with the Facility;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. DEFINITIONS

In addition to terms defined in the recitals hereto, the following terms shall have the meanings set forth below. Any capitalized terms used in this Agreement and not defined herein shall have the same meaning as ascribed to such terms under the ISO-NE Practices and ISO-NE Rules.

"Adjusted Price" shall mean the purchase price(s) for Energy referenced in Section 5.1 if the RECs fail to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit and Buyer does not purchase the RECs pursuant to Section 4.1(b) hereof.

"Affiliate" shall mean, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries Controls, is Controlled by, or is under common Control with, such first Person.

"Agreement" shall have the meaning set forth in the first paragraph of this Agreement.

"Business Day" means a day on which Federal Reserve member banks in New York, New York are open for business; and a Business Day shall start at 8:00 a.m. and end at 5:00 p.m. Eastern Prevailing Time. Notwithstanding the foregoing, with respect to notices only, a Business Day shall not include the Friday immediately following the U.S. Thanksgiving holiday.

"Buyer's Percentage Entitlement" shall mean Buyer's rights to [________] percent ([__]%) of the Products, up to and including the Contract Maximum Amount.

"Buyer's Taxes" shall have the meaning set forth in Section 5.4(a) hereof.

"**Cash**" shall mean U.S. dollars held by or on behalf of a Party as Posted Collateral hereunder. ***[NATIONAL GRID VERSION]***

"Certificates" shall mean an electronic certificate created pursuant to the Operating Rules of the GIS or any successor thereto to represent the "generation attributes" (as defined in 225 CMR 14.02) of each MWh of Energy generated within the ISO-NE control area and the generation attributes of certain Energy imported into the ISO-NE control area.

"**Collateral Account**" shall have the meaning specified in Section 6.5(a)(iii)(B) hereof. ***[NATIONAL GRID VERSION]***

"**Collateral Interest Rate**" shall mean the rate published in *The Wall Street Journal* as the "Prime Rate" from time to time (or, if more than one such rate is published, the arithmetic mean of such rates), or, if such rate is no longer published, a successor rate agreed to by Buyer and Seller, in each case determined as of the date the obligation to pay interest arises, but in no event more than the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties. ***[NATIONAL GRID VERSION]***

"**Collateral Requirement**" shall mean at any time the amount of Development Period Security or Operating Period Security required under this Agreement at such time. ***[NATIONAL GRID VERSION]***

"Commercial Operation Date" shall mean the date on which the conditions set forth in Section 3.4(b) have been satisfied, as set out in a written notice from Seller to Buyer.

"Common Infrastructure" shall mean (i) any tie or transmission line, interconnection facility or Network Upgrade that is shared by the Facility and another generating facility (ii) any non-public road that is shared by the Facility and another generating facility and (iii) any control or communications facility or other infrastructure that is located within a five-mile radius of the Facility and is shared by the Facility and another generating facility.

"Companion Facility" shall have the meaning specified in Section 4.1(d) hereof.

"Contract Maximum Amount" shall mean [___] kWh per hour of Energy and a corresponding portion of all other Products.

"Contract Year" shall mean the twelve (12) consecutive calendar months starting on the first day of the calendar month following the Commercial Operation Date and each subsequent twelve (12) consecutive calendar month period; provided that the first Contract Year shall include the days in the prior month in which the Commercial Operation Date occurred.

"Control" shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise.

"Cover Damages" shall mean, with respect to any Delivery Failure, an amount equal to (a) the positive net amount, if, any, by which the Replacement Price exceeds the applicable Price that would have been paid pursuant to Section 5.1 hereof, multiplied by the quantity of that Delivery Failure, plus (b) any applicable penalties and other costs assessed by ISO-NE or any other Person against Buyer as a result of Seller's failure to deliver such Products in accordance with the terms of this Agreement. Buyer shall provide a statement for the applicable period explaining in reasonable detail the calculation of any Cover Damages.

"Credit Support" shall mean collateral in the form of (a) cash or (b) a letter of credit issued by a Qualified Bank in a form reasonably acceptable to the recipient Party. ***[NSTAR/UNITIL/WMECO VERSION]***

"Credit Support" shall have the meaning specified in Section 6.2(d) hereof. ***[NATIONAL GRID VERSION]***

"**Credit Support Delivery Amount"** shall have the meaning specified in Section 6.3 hereof. ***[NATIONAL GRID VERSION]***

"**Credit Support Return Amount**" shall have the meaning specified in Section 6.4 hereof. ***[NATIONAL GRID VERSION]***

"Critical Milestones" shall have the meaning set forth in Section 3.1 hereof.

"**Custodian**" shall have the meaning specified in Section 6.5(a)(i) hereof. ***[NATIONAL GRID VERSION]***

"**Day Ahead Energy Market**" shall have the meaning set forth in the ISO-NE Rules.

"Default" shall mean any event or condition which, with the giving of notice or passage of time or both, could become an Event of Default.

"Defaulting Party" shall mean the Party with respect to which a Default or Event of Default has occurred.

"Delay Damages" shall mean the damages assessed pursuant to Section 3.2(a) hereof.

"Deliver" or **"Delivery"** shall mean with respect to (i) Energy, to supply Energy into Buyer's ISO-NE account at the Delivery Point in accordance with the terms of this Agreement and the ISO-NE Rules, and (ii) RECs, to supply RECs in accordance with Section 4.7(e).

"Delivery Failure" shall have the meaning set forth in Section 4.3 hereof.

"Delivery Point" shall mean the specific Node on the ISO-NE Pool Transmission Facilities, as determined by ISO-NE, where Seller shall transmit its Energy to Buyer, as set forth in Exhibit A hereto.

"Development Period Security" shall have the meaning set forth in Section [6.1(a)] [6.2(a)] hereof.

"DOER" shall mean the Massachusetts Department of Energy Resources and shall include its successors.

"Dispute" shall have the meaning set forth in Section 11.1 hereof.

"**Disputing Party**" shall have the meaning set forth in Section 6.6(a) hereof.
[NATIONAL GRID VERSION]

"Eastern Prevailing Time" shall mean either Eastern Standard Time or Eastern Daylight Savings Time, as in effect from time to time.

"Effective Date" shall have the meaning set forth in the first paragraph hereof.

"Energy" shall mean electric "energy," as such term is defined in the ISO-NE Tariff, generated by the Facility as measured in kWh in Eastern Prevailing Time, less such Facility's station service use, generator lead losses and transformer losses, which quantity for purposes of this Agreement will never be less than zero.

"Environmental Attributes" shall mean any and all generation attributes under the DOER's RPS regulations and under any and all other international, federal, regional, state or other law, rule, regulation, bylaw, treaty or other intergovernmental compact, decision, administrative decision, program (including any voluntary compliance or membership program), competitive market or business method (including all credits, certificates, benefits, and emission measurements, reductions, offsets and allowances related thereto) that are attributable, now or in the future, to Buyer's Percentage Entitlement to the favorable generation or environmental attributes of the Facility or the Products produced by the Facility, up to and including the Contract Maximum Amount, during the Services Term including Buyer's Percentage Entitlement to: (a) any such credits, certificates, benefits, offsets and allowances computed on the basis of the Facility's generation using renewable technology or displacement of fossil-fuel derived or other conventional energy generation; (b) any Certificates issued pursuant to the GIS in connection with Energy generated by the Facility; and (c) any voluntary emission reduction credits obtained or obtainable by Seller in connection with the generation of Energy by the Facility; provided, however, that Environmental Attributes shall not include: (i) any production tax credits; (ii) any investment tax credits or other tax credits associated with the construction or ownership of the Facility; or (iii) any state, federal or private grants, financing, guarantees or other credit support relating to the construction or ownership, operation or maintenance of the Facility or the output thereof.

"Event of Default" shall have the meaning set forth in Section 9.1 hereof and shall include the events and conditions described in Section 9.1 and Section 9.2 hereof.

"EWG" shall mean an exempt wholesale generator under 15 U.S.C. § 79z-5a, as amended from time to time.

"Facility" shall have the meaning set forth in the Recitals.

"FERC" shall mean the United States Federal Energy Regulatory Commission, and shall include its successors.

"Financial Closing Date" shall mean the date of signing of the initial agreements for any Financing of the Facility and of an initial disbursement of funds under such agreements.

"Financing" shall mean indebtedness, whether secured or unsecured, loans, guarantees, notes, equity, convertible debt, sale-leaseback or other tax-equity transactions, bond issuances, recapitalizations and all similar financing or refinancing.

"Force Majeure" shall have the meaning set forth in Section 10.1(a) hereof.

"Generation Unit" shall mean a facility that converts a fuel or an energy resource into electrical energy.

"GIS" shall mean the New England Power Pool Generation Information System or any successor thereto, which includes a generation information database and certificate system, operated by NEPOOL, its designee or successor entity, that accounts for generation attributes of electricity generated or consumed within New England.

"Good Utility Practice" shall mean compliance with all applicable laws, codes and regulations, all ISO-NE Rules and ISO-NE Practices, and any practices, methods and acts engaged in or approved by a significant portion of the electric industry in New England during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather is intended to include acceptable practices, methods and acts generally accepted in the industry in New England.

"<u>Governmental Entity</u>" shall mean any federal, state or local governmental agency, authority, department, instrumentality or regulatory body, and any court or tribunal, with jurisdiction over Seller, Buyer or the Facility.

"<u>Interconnecting Utility</u>" shall mean that the utility (which may be Buyer or an Affiliate of Buyer) providing interconnection service for the Facility to the transmission system of that utility.

"<u>Interconnection Agreement</u>" shall mean an agreement between Seller and the Interconnecting Utility regarding the interconnection of the Facility to the transmission system of the Interconnecting Utility, as the same may be amended from time to time.

"<u>Interconnection Point</u>" shall have the meaning set forth in the Interconnection Agreement.

"**<u>Interest Amount</u>**" shall mean with respect to a Party and an Interest Period, the sum of the daily interest amounts for all days in such Interest Period; each daily interest amount to be determined by such Party as follows: (a) the amount of Cash held by such Party on that day (but excluding any interest previously earned on such Cash); multiplied by (b) the Collateral Interest Rate for that day; divided by (c) 360. ***[NATIONAL GRID VERSION]***

"**<u>Interest Period</u>**" shall mean the period from (and including) the last Business Day on which an Interest Amount was Transferred by Buyer (or if no Interest Amount has yet been Transferred by Buyer, the Business Day on which Cash was Transferred to Seller) to (but excluding) the Business Day on which the current Interest Amount is to be Transferred. ***[NATIONAL GRID VERSION]***

"<u>ISO</u>" or **"<u>ISO-NE</u>"** shall mean ISO New England Inc., the independent system operator established in accordance with the RTO arrangements for New England, or its successor.

"<u>ISO-NE Practices</u>" shall mean the ISO-NE practices and procedures for delivery and transmission of energy in effect from time to time and shall include, without limitation, applicable requirements of the NEPOOL Agreement, and any applicable successor practices and procedures.

"<u>ISO-NE Rules</u>" shall mean all rules and procedures adopted by NEPOOL, ISO-NE, or the RTO, and governing wholesale power markets and transmission in New England, as such rules may be amended from time to time, including but not limited to, the ISO-NE Tariff, the ISO-NE Operating Procedures (as defined in the ISO-NE Tariff), the ISO-NE Planning Procedures (as defined in the ISO-NE Tariff), the Transmission Operating Agreement (as defined in the ISO-NE Tariff), the Participants Agreement, the manuals, procedures and business process documents published by ISO-NE via its web site and/or by its e-mail distribution to appropriate NEPOOL participants and/or NEPOOL committees, as amended, superseded or restated from time to time.

"<u>ISO-NE Tariff</u>" shall mean ISO-NE's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, as amended from time to time.

"ISO Settlement Market System" shall have the meaning as set forth in the ISO-NE Tariff.

"kW" shall mean a kilowatt.

"kWh" shall mean a kilowatt-hour.

"Late Payment Rate" shall have the meaning set forth in Section 5.3 hereof.

"Law" shall mean all federal, state and local statutes, regulations, rules, orders, executive orders, decrees, policies, judicial decisions and notifications.

"Lender" shall mean any party providing financing for the development and construction of the Facility, or any refinancing of that financing, and receiving a security interest in the Facility, and shall include any assignee or transferee of such a party and any trustee, collateral agent or similar entity acting on behalf of such a party.

"**Letter of Credit**" shall mean an irrevocable, non-transferable, standby letter of credit, issued by a Qualified Institution utilizing a form acceptable to the Party in whose favor such letter of credit is issued. All costs relating to any Letter of Credit shall be for the account of the Party providing that Letter of Credit. ***[NATIONAL GRID VERSION]***

"**Letter of Credit Default**" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events (a) the issuer of such Letter of Credit shall fail to be a Qualified Institution; (b) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (c) the issuer of the Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; or (d) the Letter of Credit shall expire or terminate or have a Value of $0 at any time the Party on whose account that Letter of Credit is issued is required to provide Credit Support hereunder and that Party has not Transferred replacement Credit Support meeting the requirements of this Agreement; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be cancelled or returned in accordance with the terms of this Agreement. ***[NATIONAL GRID VERSION]***

"MDPU" shall mean the Massachusetts Department of Public Utilities and shall include its successors.

"Meters" shall have the meaning set forth in Section 4.6(a) hereof.

"Moody's" shall mean Moody's Investors Service, Inc., and any successor thereto.

"MW" shall mean a megawatt.

"MWh" shall mean a megawatt-hour (one MWh shall equal 1,000 kWh).

"NEPOOL" shall mean the New England Power Pool and any successor organization.

"NEPOOL Agreement" shall mean the Second Amended and Restated New England Power Pool Agreement dated as of February 1, 2005, as amended and/or restated from time to time.

"NERC" shall mean the North American Electric Reliability Council and shall include any successor thereto.

"Network Upgrades" shall mean upgrades to the Pool Transmission Facilities and the Transmission Provider's transmission system necessary for Delivery of the Energy to the Delivery Point, as determined and identified in the interconnection study approved in connection with construction of the Facility, such that the maximum output of the Facility could be qualified to participate in the ISO-NE Forward Capacity Market (as defined in the ISO-NE Rules) or any successor thereof.

"Node" shall have the meaning set forth in Market Rule 1.

"Non-Defaulting Party" shall mean the Party with respect to which a Default or Event of Default has not occurred.

"**Obligations**" shall have the meaning specified in Section 6.1 hereof. ***[NATIONAL GRID VERSION]***

"Operational Limitations" of the Facility are the parameters set forth in Exhibit A describing the physical limitations of the Facility, including the time required for start-up and the limitation on the number of scheduled start-ups per Contract Year.

"Operating Period Security" shall have the meaning set forth in Section [6.1(b)] [6.2(b)] hereof.

"Party" and **"Parties"** shall have the meaning set forth in the first paragraph of this Agreement.

"Permits" shall mean any permit, authorization, license, order, consent, waiver, exception, exemption, variance or other approval by or from, and any filing, report, certification, declaration, notice or submission to or with, any Governmental Entity required to authorize action, including any of the foregoing relating to the ownership, siting, construction, operation, use or maintenance of the Facility under any applicable Law.

"Person" shall mean an individual, partnership, corporation, limited liability company, limited liability partnership, limited partnership, association, trust, unincorporated organization, or a government authority or agency or political subdivision thereof.

"Pool Transmission Facilities" has the meaning given that term in the ISO-NE Rules.

"**Posted Collateral**" shall mean all Credit Support and all proceeds thereof that have been Transferred to or received by a Party under this Agreement and not Transferred to the Party providing the Credit Support or released by the Party holding the Credit

Support. Any Interest Amount or portion thereof not Transferred will constitute Posted Collateral in the form of Cash. ***[NATIONAL GRID VERSION]***

"**Power Cost Reconciliation Tariff**" shall mean a fully reconciling cost recovery tariff mechanism that authorizes the establishment of a distribution charge that fully recovers Buyer's net costs under this Agreement (including the annual remuneration of two and three-quarters percent (2.75%)). The rate reconciliation shall be designed in such a way as to limit the build up of any under or over-recoveries over the course of the year. A reconciliation shall occur at least annually, but may also be reconciled quarterly or monthly, to the extent necessary to eliminate regulatory lag for the recovery of costs or crediting of over-recoveries to customers.

"Price" shall mean the purchase price(s) for Products referenced in Section 5.1 hereof.

"Products" shall mean [Energy and/or RECs]; provided, however, that [Energy and/or RECs] generated by the Facility during the Test Period or in excess of the Contract Maximum Amount and RECs not purchased by Buyer under Section 4.1(b) shall not be deemed Products. *[dependent on accepted bid]*

"**Purchased Power Accounting Authorization**" shall mean authorization for Buyer, at Buyer's sole discretion, to take appropriate steps to assure avoidance of a material, negative balance sheet impact on Buyer or Buyer's direct or indirect parent company, upon appropriate filing with and approval by the MDPU; provided that, subject to Section 8.3, such Purchased Power Accounting Authorization shall not impact Buyer's obligation to purchase the Products under this Agreement or the Price Buyer pays for such Products.

"QF" shall mean a cogeneration or small power production facility which meets the criteria as defined in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207, as amended from time to time.

"Qualified Bank" shall mean a major U.S. commercial bank or the U.S. branch office of a major foreign bank, in either case, having (x) assets on its most recent audited balance sheet of at least $10,000,000,000 and (y) a rating for its senior long-term unsecured debt obligations of at least (A) "A" by S&P and "A2" by Moody's, if such entity is rated by both S&P and Moody's or (B) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both. ***[NSTAR/UNITIL/WMECO VERSION]***

"Qualified Institution" shall mean a major U.S. commercial bank or trust company, the U.S. branch office of a foreign bank, or another financial institution, in any case, organized under the laws of the United States or a political subdivision thereof having assets of at least $10 billion and a credit rating of at least (A) "A2" from Moody's or "A" from S&P, if such entity is rated by both S&P and Moody's or (B) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both. ***[NATIONAL GRID VERSION]***

"Real-Time Energy Market" shall have the meaning as set forth in the ISO-NE Rules.

"<u>Reference Market-Maker</u>" shall mean a leading dealer in the relevant market that is selected in a commercially reasonable manner and is not an affiliate of either party. ***[NATIONAL GRID VERSION]***

"<u>Regulatory Approval</u>" shall mean the MDPU's approval of this entire Agreement, which approval shall include without limitation: (1) confirmation that this Agreement has been approved under Section 83A of Massachusetts Senate Bill 2395, *An Act relative to competitively priced electricity in the Commonwealth*, and the regulations promulgated thereunder and that all of the terms of such Section 83A and such regulations apply to this Agreement; (2) definitive regulatory authorization for Buyer to recover all of its costs incurred under this Agreement for the entire term of this Agreement through the implementation of a Power Cost Reconciliation Tariff and/or other cost recovery or reconciliation mechanisms; (3) definitive regulatory authorization for Buyer to recover remuneration equal to two and three-quarters percent (2.75%) of Buyer's annual payments under this Agreement for the term of this Agreement through the Power Cost Reconciliation Tariff; and (4) approval of any Purchased Power Accounting Authorization requested by Buyer in connection with the Regulatory Approval. Such approvals shall be acceptable in form and substance to Buyer in its sole discretion, shall not include any conditions or modifications that Buyer deems, in its sole discretion, to be unacceptable and shall be final and not subject to appeal or rehearing.

"<u>Rejected Purchase</u>" shall have the meaning set forth in Section 4.4 hereof.

"<u>Renewable Energy Certificates</u>" or **"<u>RECs</u>"** shall mean all of the Certificates and any and all other Environmental Attributes associated with the Products or otherwise produced by the Facility which satisfy the RPS for a RPS Class I Renewable Generation Unit, and shall represent title to and claim over all Environmental Attributes associated with the specified MWh of generation from such RPS Class I Renewable Generation Unit.

"<u>Replacement Energy</u>" shall mean Energy purchased by Buyer as replacement for any Delivery Failure.

"<u>Replacement Price</u>" shall mean the price at which Buyer, acting in a commercially reasonable manner, purchases Replacement Energy and Replacement RECs plus (i) transaction and other administrative costs reasonably incurred by Buyer in purchasing such Replacement Energy and Replacement RECs and (ii) additional transmission charges, if any, reasonably incurred by Buyer to transmit Replacement Energy to the Delivery Point; provided, however, that (a) in no event shall Buyer be required to utilize or change its utilization of its owned or controlled assets, contracts or market positions to minimize Seller's liability, (b) Buyer shall have no obligation to purchase Replacement Energy and/or Replacement RECs, and (c) if Buyer does not purchase Replacement Energy and/or Replacement RECs, the market value of Energy and/or RECs at the time of the Delivery Failure (as reasonably determined by Buyer) will replace the price at which Buyer purchases Replacement Energy and/or Replacement RECs in the calculation of the Replacement Price.

"Replacement RECs" shall mean any generation or environmental attributes, including any Certificates or other certificates or credits related thereto reflecting generation by a RPS Class I Renewable Generation Unit that are purchased by Buyer as replacement for any Delivery Failure.

"Request Date" shall have the meaning set forth in Section 6.6(a) hereof. ***[NATIONAL GRID VERSION]***

"**Requesting Party**" shall have the meaning set forth in Section 6.6(a) hereof. ***[NATIONAL GRID VERSION]***

"Resale Damages" shall mean, with respect to any Rejected Purchase, an amount equal to (a) the positive net amount, if any, by which the applicable Price that would have been paid pursuant to Section 5.1 hereof for such Rejected Purchase, had it been accepted, exceeds the Resale Price multiplied by the quantity of that Rejected Purchase, plus (b) any applicable penalties assessed by ISO-NE or any other Person against Seller as a result of Buyer's failure to accept such Products. Seller shall provide a written statement explaining in reasonable detail the calculation of any Resale Damages.

"Resale Price" shall mean the price at which Seller, acting in a commercially reasonable manner, sells or is paid for a Rejected Purchase, plus transaction and other administrative costs reasonably incurred by Seller in re-selling such Rejected Purchase; provided, however, that in no event shall Seller be required to utilize or change its utilization of the Facility or its other assets, contracts or market positions in order to minimize Buyer's liability for such Rejected Purchase.

"**Rounding Amount**" shall have the meaning specified in Section 6.2(c) hereof. ***[NATIONAL GRID VERSION]***

"RPS" shall mean the requirements established pursuant to Mass. Gen. Laws ch. 25A, § 11F that require all retail electricity suppliers in Massachusetts to provide a minimum percentage of electricity from RPS Class I Renewable Generation Units, and such successor laws and regulations as may be in effect from time to time.

"RPS Class I Renewable Generation Unit" shall mean a Generation Unit that has received a Statement of Qualification from the DOER, including a Generation Unit termed a New Renewable Generation Unit in a Statement of Qualification issued by the DOER pursuant to 225 CMR 14.00.

"RTO" shall mean ISO-NE and any successor organization or entity to ISO-NE, as authorized by FERC to exercise the functions pursuant to the FERC's Order No. 2000 and FERC's corresponding regulations, or any successor organization, or any other entity authorized to exercise comparable functions in subsequent orders or regulations of FERC.

"S&P" shall mean Standard & Poor's Financial Services LLC , and any successor thereto.

"Schedule or Scheduling" shall mean the actions of Seller and/or its designated representatives pursuant to Section 4.2, of notifying, requesting and confirming to ISO-NE the quantity of Energy to be delivered on any given day or days (or in any given hour or hours) during the Services Term at the Delivery Point.

"Services Term" shall have the meaning set forth in Section 2.2(b) hereof.

"Seller's Taxes" shall have the meaning set forth in Section 5.4(a) hereof.

"**Statement of Qualification**" shall mean a written document from the DOER that qualifies a Generation Unit as an RPS Class I Qualified Generation Unit, or that qualifies a portion of the annual electrical energy output of a Generation Unit as RPS Class I Renewable Generation (as defined in 225 CMR 14.01).

"**Substitute Credit Support**" shall have the meaning assigned in Section 6.5(f) hereof. ***[NATIONAL GRID VERSION]***

"Term" shall have the meaning set forth in Section 2.2(a) hereof.

"Termination Payment" shall have the meaning set forth in Section 9.3(b) hereof.

"Test Period" shall have the meaning set forth in Section 3.4(a) hereof.

"Transfer" shall mean, with respect to any Posted Collateral or Interest Amount, and in accordance with the instructions of the Party entitled thereto:

(a) in the case of Cash, payment or transfer by wire transfer into one or more bank accounts specified by the Party to whom such Cash is being delivered; and

(b) in the case of Letters of Credit, delivery of the Letter of Credit or an amendment thereto to the Party to whom such Letter of Credit is being delivered. ***[NATIONAL GRID VERSION]***

"Transmission Provider" shall mean (a) ISO-NE, its respective successor or Affiliates; (b) Buyer; and/or (c) such other third parties from whom transmission services are necessary for Seller to fulfill its performance obligations to Buyer hereunder, as the context requires.

"Valuation Agent" means the Requesting Party; provided, however, that that in all cases, if an Event of Default has occurred and is continuing with respect to the Party designated as the Valuation Agent, then in such case, and for so long as the Event of Default continues, the other Party shall be the Valuation Agent. ***[NATIONAL GRID VERSION]***

"Valuation Date" shall mean each Business Day. ***[NATIONAL GRID VERSION]***

"**Valuation Percentage**" shall have the meaning specified in Section 6.2(d) hereof. ***[NATIONAL GRID VERSION]***

"**Valuation Time**" shall mean the close of business on the Business Day before the Valuation Date or date of calculation, as applicable. ***[NATIONAL GRID VERSION]***

"**Value**" shall mean, with respect to Posted Collateral or Credit Support, the Valuation Percentage multiplied by the amount then available under the Letter of Credit to be unconditionally drawn by Buyer. ***[NATIONAL GRID VERSION]***

2. EFFECTIVE DATE; TERM

2.1 Effective Date. Subject to Section 8.1, this Agreement is effective as of the Effective Date.

2.2 Term.

(a) The "**Term**" of this Agreement is the period beginning on the Effective Date and ending upon the final settlement of all obligations hereunder after the expiration of the Services Term or the earlier termination of this Agreement in accordance with its terms.

(b) The "**Services Term**" is the period during which Buyer is obligated to purchase Products Delivered to Buyer by Seller (not including Energy and RECs Delivered during the Test Period under Section 4.8) commencing on the Commercial Operation Date and continuing for a period of [10 to 20] years from the Commercial Operation Date, unless this Agreement is earlier terminated in accordance with the provisions hereof.

(c) At the expiration of the Services Term, the Parties shall no longer be bound by the terms and provisions hereof (including, without limitation, any payment obligation hereunder), except (i) to the extent necessary to provide invoices and make payments or refunds with respect to Products delivered prior to such expiration or termination, (ii) to the extent necessary to enforce the rights and the obligations of the Parties arising under this Agreement before such expiration or termination, and (iii) the obligations of the Parties hereunder with respect to confidentiality and indemnification shall survive the expiration or termination of this Agreement.

(d) At the expiration of the Services Term, Buyer shall have the right, exercisable in Buyer's sole discretion, to negotiate in good faith with Seller for no more than sixty (60) days, the terms of the sale of such Energy and/or RECs generated by the Facility (or a portion thereof, as selected by Buyer) to Buyer or its designee on an exclusive basis. If Buyer wishes to enter into such negotiation, Buyer shall notify Seller of such decision at least one year prior to the expiration of the Services Term, and such negotiations shall commence at least eleven months prior to the expiration of the Services Term. Seller shall supply in a timely manner, information regarding the Facility which is customary to allow Buyer to perform due diligence and to negotiate in good faith for the purchase of such Energy and/or RECs.

3. FACILITY DEVELOPMENT AND OPERATION

3.1 Critical Milestones.

(a) Subject to the provisions of Section 3.1(c), commencing on the Effective Date, Seller shall develop the Facility in order to achieve the following milestones (**"Critical Milestones"**) on or before the date set forth in this Section 3.1(a):

(i) receipt of all Permits necessary to construct the Facility, as set forth in Exhibit B, in final form, by [_________];

(ii) acquisition of all required real property rights necessary for construction and operation of the Facility, interconnection of the Facility to the Interconnecting Utility, and performance of Seller's obligations under this Agreement as set forth on Exhibit B, by [_________];

(iii) demonstration of the financial capability (whether through third party financing to Seller or Seller's own financial assets) to proceed with the development and construction of the Facility, including, as applicable, Seller's financial obligations with respect to interconnection of the Facility to the Interconnecting Utility and construction of the Network Upgrades by [__________] [on or before 12/31/15] [*TBD for alternative bid*]; and

(iv) achievement of the Commercial Operation Date by [___________] [on or before 12/31/16] [on or before 12/31/18 *for alternative bid*].

(b) Seller shall provide Buyer with written notice of the achievement of each Critical Milestone within seven (7) days after that achievement, which notice shall include information demonstrating with reasonable specificity that such Critical Milestone has been achieved. Seller acknowledges that Buyer requires such written notice solely for monitoring purposes, and that nothing set forth in this Agreement shall create or impose upon Buyer any responsibility or liability for the development, construction, operation or maintenance of the Facility.

(c) In addition to any extension of a date for a Critical Milestone as a result of a Force Majeure under Section 10.1, Seller may elect to extend all of the dates for the Critical Milestones not yet achieved (i) by one year without posting additional Development Period Security and (ii) by up to two additional six month periods by posting additional Development Period Security of $[________] [$5 per kWh of Contract Maximum Amount] for each such six-month period. In no event may Seller exercise the right to extend the Critical Milestone dates under this Section 3.1(c) by more than two years, and in no event shall any extension of the Critical Milestone dates as a result of one or more Force Majeure events exceed a cumulative total of an additional twelve (12) months. Any such election shall be made in a written notice delivered to Buyer on or prior to the first date for a Critical Milestone that has not yet been achieved (as such date may have previously been extended).

(d) The Parties agree that time is of the essence with respect to the Critical Milestones and is part of the consideration to Buyer in entering into this Agreement.

3.2 Delay Damages.

(a) If the Commercial Operation Date is not achieved by the date set forth therefor in Section 3.1(a) (as extended pursuant to Section 3.1(c)), Seller shall pay to Buyer damages for each month from and after such date until the Commercial Operation Date at the rate of $[___] per month [$1.50 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $1.00 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $0.50 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] up to a maximum of twelve (12) months of delay, pro rated for partial months (**"Delay Damages"**). Delay Damages shall be due under this Section 3.2(a) without regard to whether Buyer exercises its right to terminate this Agreement pursuant to Section 9.3; provided, however, that if Buyer exercises its right to terminate this Agreement under Section 9.3, Delay Damages shall be due and owing to the extent that such Delay Damages were due and owing at the date of such termination.

(b) Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to Seller's delay in achieving the Commercial Operation Date would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties and set forth herein are a fair and reasonable calculation of such damages. Notwithstanding the foregoing, this Article shall not limit the amount of damages payable to Buyer if this Agreement is terminated as a result of Seller's failure to achieve the Commercial Operation Date. Any such termination damages shall be determined in accordance with Article 9.

(c) By the tenth (10th) day following the end of the calendar month in which Delay Damages first become due and continuing by the tenth (10th) day of each calendar month during the period in which Delay Damages accrue (and the following months if applicable), Buyer shall deliver to Seller an invoice showing Buyer's computation of such damages and any amount due Buyer in respect thereof for the preceding calendar month. No later than ten (10) days after receiving such an invoice, Seller shall pay to Buyer, by wire transfer of immediately available funds to an account specified in writing by Buyer or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice. If Seller fails to pay such amounts when due, Buyer may draw upon the Development Period Security for payment of such Delay Damages, and Buyer may exercise any other remedies available for Seller's default hereunder.

3.3 Construction.

(a) Progress Reports. At the end of each calendar quarter after the Effective Date and until the Commercial Operation Date, Seller shall provide Buyer with a progress report regarding Critical Milestones not yet achieved, including projected time to completion of the Facility, in accordance with the form attached hereto as Exhibit C, and shall provide supporting documents and detail regarding the same upon Buyer's request. Seller shall permit Buyer and its advisors and consultants to review and discuss with Seller and its advisors and consultants such progress reports during business hours and upon reasonable notice to Seller.

(b) Site Access. Buyer and its representatives shall have the right but not the obligation, during business hours and upon reasonable notice to Seller, to inspect the Facility site and monitor the construction of the Facility.

3.4 Commercial Operation.

(a) Seller's obligation to Deliver the Products and Buyer's obligation to pay Seller for such Products commences on the Commercial Operation Date; provided, that Energy and RECs generated by the Facility prior to the Commercial Operation Date (the **"Test Period"**) shall not be deemed Products.

(b) The Commercial Operation Date shall occur on the date on which the Facility is substantially completed as described in Exhibit A and capable of regular commercial operation in accordance with Good Utility Practice, the manufacturer's guidelines for all material components of the Facility, all requirements of the ISO-NE Rules and ISO-NE Practices for the delivery of the Products to the Seller have been satisfied, and all performance testing for the Facility has been successfully completed, provided Seller has also satisfied the following conditions precedent as of such date:

(i) completion of all transmission and interconnection facilities and any Network Upgrades, including final acceptance and authorization to interconnect the Facility from ISO-NE or the Interconnecting Utility in accordance with the fully executed Interconnection Agreement;

(ii) Seller has obtained and demonstrated possession of all Permits required for the lawful construction and operation of the Facility, for the interconnection of the Facility to the Interconnecting Utility (including any Network Upgrades) and for Seller to perform its obligations under this Agreement, including but not limited to Permits related to environmental matters, all as set forth on Exhibit B;

(iii) Seller has obtained a Statement of Qualification from the DOER pursuant to 225 CMR 14.05 qualifying the Facility as a RPS Class I Renewable Generation Unit;

(iv) Seller has acquired all real property rights needed to construct and operate the Facility, to interconnect the Facility to the Interconnecting Utility, to construct the Network Upgrades (to the extent that it is Seller's responsibility to do so) and to perform Seller's obligations under this Agreement;

(v) Seller has established all ISO-NE-related accounts and entered into all ISO-NE-related agreements required for the performance of Seller's obligations in connection with the Facility and this Agreement, which agreements shall be in full force and effect, including the registration of the Facility in the GIS;

(vi) Seller has provided to Buyer I.3.9 confirmation from ISO-NE regarding approval of generation entry, has submitted the Asset Registration Form (as defined in ISO-NE Practices) for the Facility to ISO-NE and has taken such other actions as are necessary to effect the transfer of the Energy to Buyer in the ISO Settlement Market System;

(vii) Seller has successfully completed all pre-operational testing and commissioning in accordance with manufacturer guidelines;

(viii) Seller has satisfied all Critical Milestones that precede the Commercial Operation Date in Section 3.1;

(ix) no Default or Event of Default by Seller shall have occurred and remain uncured; and

(x) the Facility is owned or leased by, and under the care, custody and control of, Seller.

3.5 Operation of the Facility.

(a) Compliance With Utility Requirements. Seller shall comply with, and cause the Facility to comply with: (i) Good Utility Practice; (ii) the Operational Limitations; and (iii) all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by ISO-NE, any Transmission Provider, any Interconnecting Utility, NERC and/or any regional reliability entity, including, in each case, all practices, requirements, rules, procedures and standards related to Seller's construction, ownership, operation and maintenance of the Facility and its performance of its obligations under this Agreement (including obligations related to the generation, Scheduling, interconnection, and transmission of Energy, and the transfer of RECs), whether such requirements were imposed prior to or after the Effective Date. Seller shall be solely responsible for registering as the "Generator Owner and Generator Operator" of the Facility with NERC and any applicable regional reliability entities.

(b) Permits. Seller shall maintain in full force and effect all Permits necessary for it to perform its obligations under this Agreement, including all Permits necessary to operate and maintain the Facility.

(c) Maintenance and Operation of Facility. Seller shall, at all times during the Term, construct, maintain and operate the Facility in accordance with Good Utility Practice and in accordance with Exhibit A to this Agreement. Seller shall bear all costs related thereto. Seller may contract with other Persons to provide discrete construction, operation and maintenance functions, so long as Seller maintains overall control over the construction, operation and maintenance of the Facility throughout the Term.

(d) Interconnection Agreement. Seller shall comply with the terms and conditions of the Interconnection Agreement.

(e) ISO-NE Status. Seller shall, at all times during the Services Term, either: (i) be an ISO-NE "Market Participant" pursuant to the ISO-NE Rules; or (ii) have entered into an agreement with a Market Participant that shall perform all of Seller's ISO-NE-related obligations in connection with the Facility and this Agreement.

(f) Forecasts. Commencing at least thirty (30) days prior to the anticipated Commercial Operation Date and continuing throughout the Term, Seller shall update and deliver to Buyer on a monthly basis and in a form reasonably acceptable to Buyer, twelve (12) month rolling forecasts of Energy production by the Facility, which forecasts shall be prepared in good faith and in accordance with Good Utility Practice based on historical performance, maintenance schedules, Seller's generation projections and other relevant data and considerations. Any notable changes from prior forecasts or historical energy delivery shall be noted and an explanation provided. The provisions of this section are in addition to Seller's requirements under ISO-NE Rules and ISO-NE Practices, including ISO-NE Operating Procedure No. 5.

(g) RPS Class I Renewable Generation Unit. Seller shall be solely responsible for qualifying the Facility with the DOER as a RPS Class I Renewable Generation Unit in accordance with 225 CMR 14.05 and maintaining such Statement of Qualification throughout the Services Term; provided, however, that if the Facility ceases to qualify as a RPS Class I Renewable Generation Unit solely as a result of a change in Law, Seller shall only be required to use commercially reasonable efforts to maintain such Statement of Qualification after that change in Law.

(h) Compliance Reporting. Within fifteen days (15) days following the end of each calendar quarter, Seller shall provide Buyer information pertaining to power plant emissions, fuel types, labor information and any other information to the extent required by Buyer to comply with the uniform disclosure requirements contained in 220 CMR 11.00 and any other such disclosure regulations which may be imposed upon Buyer during the Term, which information requirements will be provided to Seller by Buyer at least fifteen (15) days before the beginning of the calendar quarter for which the information is required. To the extent Buyer is subject to any other certification or compliance reporting requirement with respect to the Products produced by Seller and delivered to Buyer hereunder, Seller shall provide any information in its possession (or, if not in Seller's possession, available to it and not reasonably available to Buyer) requested by Buyer to permit Buyer to comply with any such reporting requirement.

(i) Insurance. Throughout the Term, and without limiting any liabilities or any other obligations of Seller hereunder, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "A-" by the A.M. Best Company the insurance coverage and with the deductibles that are customary for a generating facility of the type and size of the Facility and as otherwise legally required.. Within thirty (30) days prior to the start of each Contract Year, Seller shall provide Buyer with a certificate of insurance which (i) shall include Buyer as an additional insured on each policy, (ii) shall not include the legend "certificate is not evidence of coverage" or any statement with similar effect, (iii) shall evidence a firm obligation of the insurer to provide Buyer with thirty (30) days prior written notice of coverage modifications, and (iv) shall be endorsed by a Person who has authority to bind the insurer. If any coverage is written on a "claims-made" basis, the certification accompanying the policy shall conspicuously state that the policy is "claims made."

(j) Contacts. Each Party shall identify a principal contact or contacts, which contact(s) shall have adequate authority and expertise to make day-to-day decisions with respect to the administration of this Agreement.

(k) Compliance with Law. Without limiting the generality of any other provision of this Agreement, Seller shall be responsible for complying with all applicable requirements of Law, including all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by FERC and any other Governmental Entity, whether imposed pursuant to existing Law or procedures or pursuant to changes enacted or implemented during the Term, including all risks of environmental matters relating to the Facility or the Facility site. Seller shall indemnify Buyer against any and all claims arising out of or related to such environmental matters and against any costs imposed on Buyer as a result of Seller's violation of any applicable Law, or ISO-NE or NERC requirements. For the avoidance of doubt, Seller shall be responsible for procuring, at its expense, all Permits and governmental approvals required for the construction and operation of the Facility in compliance with Law.

(l) FERC Status. Seller shall maintain the Facility's status as a QF or EWG at all times after the Commercial Operation Date and shall obtain and maintain any requisite authority to sell the output of the Facility at market-based rates.

(m) Emissions. Seller shall be responsible for all costs associated with the Facility's emissions, including the cost of procuring emission reductions, offsets, allowances or similar items associated with the Facility's emissions, to the extent required to operate the Facility. Without limiting the generality of the foregoing, failure or inability of Seller to procure emission reductions, offsets, allowances or similar items associated with the Facility's emissions shall not constitute a Force Majeure.

3.6 Interconnection and Delivery Services.

(a) Seller shall be responsible for all costs associated with interconnection of the Facility at the Interconnection Point, including the costs of the Network Upgrades, consistent with all standards and requirements set forth by the FERC, ISO-NE, any other applicable Governmental Entity and the Interconnecting Utility.

(b) Seller shall defend, indemnify and hold Buyer harmless against any liability arising due to Seller's performance or failure to perform under the Interconnection Agreement.

3.7 New RPS Class I Renewable Generation Unit.

The Facility shall be a RPS Class I Renewable Generation Unit, qualified by the DOER as eligible to participate in the RPS program, under Section 11F of Chapter 25A of the Massachusetts General Laws (subject to Section 4.7(b) in the event of a change in Law affecting such qualification as a RPS Class I Renewable Generation Unit) and shall have a Commercial Operation Date, as verified by the DOER, on or after January 1, 2013.

4. DELIVERY OF PRODUCTS

4.1 Obligation to Sell and Purchase Products.

(a) Beginning on the Commercial Operation Date and subject to Section 4.1(b), Seller shall sell and Deliver, and Buyer shall purchase and receive, Buyer's Percentage Entitlement of the Products in accordance with the terms and conditions of this Agreement. The aforementioned obligations for Seller to sell and Deliver the Products and for Buyer to purchase and receive the same is unit contingent and shall be subject to the operation of the Facility.

(b) Buyer shall not be obligated to purchase any Products to the extent that such Products exceed the Contract Maximum Amount in any hour. In addition, Buyer shall not be obligated to purchase any REC or comparable certificate, credit, attribute or other similar product produced by the Facility which fails to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit, and, to the extent that Buyer does not purchase any such REC or comparable certificate, credit, attribute or other similar product produced by the Facility, Seller may, in its sole discretion, sell, transfer or otherwise dispose of that REC or comparable certificate, credit, attribute or other similar product. Once Buyer notifies Seller that it will not purchase any REC or comparable certificate, credit, attribute or other similar product produced by the Facility which fails to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit, then Buyer may resume purchasing such RECs or comparable certificates, credits, attributes or other similar products produced by the Facility upon thirty (30) days' prior written notice to Seller, unless otherwise agreed by Buyer and Seller.

(c) Seller shall Deliver Buyer's Percentage Entitlement of the Products produced by the Facility, up to and including the Contract Maximum Amount, exclusively to Buyer, and Seller shall not sell, divert, grant, transfer or assign such Products or any certificate or other attribute associated with such Products to any Person other than Buyer during the Term. Seller shall not enter into any agreement or arrangement under which such Products can be claimed by any Person other than Buyer. Buyer shall have the exclusive right to resell or convey the Products in its sole discretion.

(d) Prior to Seller or an Affiliate of Seller entering into a new bilateral agreement or an amendment to an existing agreement to sell any of the output of either the Facility or another generating facility owned in whole or in part by Seller or an Affiliate of Seller that utilizes any Common Infrastructure (a **"Companion Facility"**) to another Person, Seller shall first take the actions set forth in this Section 4.1(d), as follows:

(i) Where the term of such agreement is one (1) year or more, Seller shall first offer to Buyer in writing to amend this Agreement to incorporate the terms and conditions of such other agreement or amendment. Buyer shall have twenty (20) days to either: (1) accept all of the terms and conditions of such other agreement or amendment; or (2) accept only the pricing and term provisions included in such other agreement or amendment; or (3) decline all of the terms and conditions of such other agreement or amendment. In the event Buyer chooses either option (1) or (2) above, Seller and Buyer shall amend this Agreement to reflect the accepted terms and conditions and, to the extent Buyer determines such amendment requires MDPU approval or filing, Buyer shall use commercially reasonable efforts to apply for such approval or make such filing in accordance with Section 18. No amendment of this Agreement under this Section 4.1(d)(i) shall affect the quantity of Products to be received and purchased by Buyer under this Agreement.

(ii) Prior to Seller or an Affiliate of Seller entering into a new agreement to sell any of the output of the Facility or a Companion Facility to another Person where the term of such agreement is less than one (1) year, Seller or such Affiliate of Seller shall first offer to enter into such agreement for such output with Buyer on the same terms and conditions. Buyer shall have twenty (20) days to either accept or reject such agreement. In the event Buyer chooses to enter into such agreement, Buyer and Seller or such Affiliate of Seller shall promptly execute such agreement. To the extent Buyer determines such agreement requires MDPU approval or filing, Buyer will use commercially reasonable efforts to apply for such approval or make such filing consistent with Section 18, and such agreement shall not become effective unless and until such MDPU approval is obtained or such MDPU filing is made.

(iii) If Buyer fails to notify Seller of its choice within twenty (20) days after Buyer's receipt of the offer from Seller or an Affiliate of Seller under clause (i) or (ii) above, Buyer shall be deemed to have elected to decline all of the terms and conditions of such other agreement or amendment. If any required filing with or approval by the MDPU with respect to any amendment or agreement under this Section 4.1(d) as described above is not made or received within one hundred eighty (180) days after Buyer and Seller or an Affiliate of Seller enter into such amendment or agreement, then such amendment or agreement shall be void and of no further force and effect.

(iv) If Buyer declines to enter into a new agreement or an amendment to this Agreement under this Section 4.1(d) or the MDPU filing or approval relating to such agreement or amendment is not received within one hundred eighty (180) days after Buyer and Seller or an Affiliate of Seller enter into such agreement or amendment, then Seller or such Affiliate of Seller may proceed with the proposed sale of such output of the Facility or such Companion Facility to another Person under the terms and conditions offered to Buyer.

(v) This Section 4.1(d) shall only apply to bilateral agreements entered into on or before the tenth anniversary of the Commercial Operation Date. Any transactions conducted in ISO-NE's Real-Time or Day-Ahead markets and any bilateral agreements entered into after the tenth anniversary of the Commercial Operation Date shall not be subject to this Section 4.1(d).

4.2 Scheduling and Delivery.

(a) During the Services Term, Seller shall Schedule Deliveries of Energy hereunder with ISO-NE within the defined Operational Limitations of the Facility and in accordance with this Agreement, all ISO-NE Practices and ISO-NE Rules, as applicable. Seller shall transfer the Energy to Buyer in the Day Ahead Energy Market or Real Time Energy Market, as reasonably agreed from time to time by Buyer and Seller and consistent with prevailing electric industry practices at the time, in such a manner that Buyer may resell such Energy in the Day Ahead Energy Market or Real Time Energy Market, as applicable, and Buyer shall have no obligation to pay for any Energy not transferred to Buyer in the Day Ahead Energy Market or Real Time Energy Market or for which Buyer is not credited in the ISO-NE Settlement Market System (including, without limitation, as a result of an outage on any electric transmission system).

(b) The Parties agree to use commercially reasonable efforts to comply with all applicable ISO-NE Rules and ISO-NE Practices in connection with the Scheduling and Delivery of Energy hereunder. Penalties or similar charges assessed by a Transmission Provider and caused by noncompliance with the Scheduling obligations set forth in this Section 4.2 shall be the responsibility of Seller.

(c) Without limiting the generality of this Section 4.2, Seller or the party with whom Seller contracts pursuant to Section 3.5(e) shall at all times during the Services Term be designated as the "Lead Market Participant" (or any successor designation) for the Facility and shall be solely responsible for any obligations and liabilities, including all charges, penalties and financial assurance obligations, imposed by ISO-NE or under the ISO-NE Rules and ISO-NE Practices with respect to the Facility.

4.3 Failure of Seller to Deliver Products. In the event that Seller fails to satisfy any of its obligations to Deliver any of the Products hereunder in accordance with Section 4.1 and Section 4.2, and such failure is not excused under the express terms of this Agreement (a **"Delivery Failure"**), Seller shall pay Buyer an amount for such Delivery Failure equal to the Cover Damages. Such payment shall be due no later than the date for Buyer's payment for the applicable month as set forth in Section 5.2 hereof; provided, however, that if Seller demonstrates to Buyer's reasonable satisfaction that such Delivery Failure was solely the result of an administrative error by Seller, such payment shall not be due until the later of the date for Buyer's payment for the applicable month as set forth in Section 5.2 hereof or the date that is fifteen (15) days after such Delivery Failure occurred. Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to a Delivery Failure would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Cover Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.4 Failure by Buyer to Accept Delivery of Products. If Buyer fails to accept all or part of any of the Products to be purchased by Buyer hereunder and such failure to accept is not excused under the terms of this Agreement (a **"Rejected Purchase"**), then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred, an amount for such Rejected Purchase equal to the Resale Damages. Each Party agrees and acknowledges that (i) the damages that Seller would incur due to a Rejected Purchase would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Resale Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.5 Delivery Point.

(a) All Energy shall be Delivered hereunder by Seller to Buyer at the Delivery Point. Seller shall be responsible for the costs of delivering its Energy to the Delivery Point consistent with all standards and requirements set forth by the FERC, ISO-NE and any other applicable Governmental Entity or tariff.

(b) Seller shall be responsible for all applicable charges associated with transmission interconnection, service and delivery charges, including all related ISO-NE administrative fees and other FERC-approved charges in connection with the Delivery of Energy to and at the Delivery Point.

(c) Buyer shall be responsible for all losses, transmission charges, ancillary service charges, line losses, congestion charges and other ISO-NE or applicable system costs or charges associated with transmission incurred, in each case, in connection with the transmission of Energy delivered under this Agreement from and after the Delivery Point.

4.6 Metering.

(a) Metering. All electric metering associated with the Facility, including the Facility meter and any other real-time meters, billing meters and back-up meters (collectively, the **"Meters"**), shall be installed, operated, maintained and tested at Seller's expense in accordance with Good Utility Practice and any applicable requirements and standards issued by NERC, the Interconnecting Utility, and ISO-NE; provided that each Meter shall be tested at Seller's expense once each Contract Year. The Meters shall be used for the registration, recording and transmission of information regarding the Energy output of the Facility. Seller shall provide Buyer with a copy of all metering and calibration information and documents regarding the Meters promptly following receipt thereof by Seller.

(b) Measurements. Readings of the Meters at the Facility by the Interconnecting Utility in whose territory the Facility is located (or an independent Person mutually acceptable to the Parties) shall be conclusive as to the amount of Energy generated by the Facility; provided however, that Seller, upon request of Buyer and at Buyer's expense (if more frequently than annually as provided for in Section 4.6(a)), shall cause the Meters to be tested by the Interconnecting Utility in whose territory the Facility is located, and if any Meter is out of service or is determined to be registering inaccurately by more than two percent (2%), (i) the measurement of Energy produced by the Facility shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, in accordance with the filed tariff of such Interconnecting Utility, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder and (ii) Seller shall reimburse Buyer for the cost of such test of the Meters. Meter readings shall be adjusted to take into account the losses to Deliver the Energy to the Delivery Point. Seller shall make recorded meter data available monthly to the Buyer at no cost.

(c) Inspection, Testing and Calibration. Buyer shall have the right to inspect and test any of the Meters at the Facility at reasonable times and upon reasonable notice from Buyer to Seller. Buyer shall have the right to have a representative present during any testing or calibration of the Meters at the Facility by Seller. Seller shall provide Buyer with timely notice of any such testing or calibration.

(d) Audit of Meters. Buyer shall have access to the Meters and the right to audit all information and test data related to such Meters.

(e) Notice of Malfunction. Seller shall provide Buyer with prompt notice of any malfunction or other failure of the Meters or other telemetry equipment necessary to accurately report the quantity of Energy being produced by the Facility. If any Meter is found to be inaccurate by more than two percent (2%), the meter readings shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder.

(f) Telemetry. The Meters shall be capable of sending meter telemetry data, and Seller shall provide Buyer with simultaneous access to such data at no additional cost to Buyer. This provision is in addition to Seller's requirements under ISO-NE Rules and Practices, including ISO-NE Operating Procedure No. 18

4.7 RECs.

(a) Seller shall transfer to Buyer all of the right, title and interest in and to Buyer's Percentage Entitlement of the Facility's Environmental Attributes, including the RECs, generated by the Facility during the Term in accordance with the terms of this Section 4.7.

(b) All Energy provided by Seller to Buyer from the Facility under this Agreement shall meet the requirements for eligibility pursuant to the RPS; provided, however, that if the Facility ceases to qualify as a RPS Class I Renewable Generation Unit solely as a result of a change in Law with respect to the RPS, Seller shall be required to use commercially reasonable efforts to ensure that all Energy provided by Seller to Buyer from the Facility under this Agreement meets the requirements for eligibility pursuant to the RPS after that change in Law.

(c) At Buyer's request and at Seller' sole cost, Seller shall also seek qualification under the renewable portfolio standard or similar law of New York, Connecticut and/or one or more additional New England states (in addition to Massachusetts) and/or any federal renewable energy standard. Seller shall use commercially reasonable efforts, consistent with Good Utility Practice, to maintain such qualification at all times during the Services Term, or until Buyer indicates such qualification is no longer necessary. Seller shall also submit any information required by any state or federal agency (including without limitation the MDPU) with regard to administration of its rules regarding Environmental Attributes or its renewable energy standard or renewable portfolio standard to Buyer or as directed by Buyer.

(d) Seller shall comply with all GIS Operating Rules relating to the creation and transfer of all RECs to be purchased by Buyer under this Agreement and all other GIS Operating Rules to the extent required for Buyer to achieve the full value of the RECs. In addition, at Buyer's request, Seller shall register with and comply with the rules and requirements of any other tracking system or program that tracks, monetizes or otherwise creates or enhances value for Environmental Attributes, which compliance shall be at Seller's sole cost if such registration and compliance is requested in connection with Section 4.7(c) above and shall be at Buyer's sole cost in other instances.

(e) Prior to the delivery of any Energy hereunder (including any Energy Delivered during the Test Period), either (i) Seller shall cause Buyer to be registered in the GIS as the initial owner of all Certificates to be Delivered hereunder to Buyer or (ii) Seller and Buyer shall effect an irrevocable forward transfer of the Certificates to be Delivered hereunder to Buyer in the GIS; provided, however, that no payment shall be due to Seller for any RECs until the Certificates are actually deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing.

(f) The Parties intend for the transactions entered into hereunder to be physically settled, meaning that the RECs are intended to be Delivered in the GIS account of Buyer or its designee as set forth in this Section 4.7.

4.8 Deliveries During Test Period. During the Test Period, Seller shall sell and Deliver, and Buyer shall purchase and receive Buyer's Percentage Entitlement of any Energy and RECs produced by the Facility. Notwithstanding the provisions of Section 5.1, payment for Buyer's Percentage Entitlement of all Energy and RECs produced during the Test Period shall be equal to the product of (x) Buyer's Percentage Entitlement of the MWh of Energy delivered to the Delivery Point and (y) the Real Time Locational Marginal Price at such Delivery Point (as determined by ISO-NE) for each hour of the month when Energy and RECs are produced by the Facility. In no event shall the Test Period extend beyond six months, except due to Force Majeure.

5. PRICE AND PAYMENTS FOR PRODUCTS

5.1 Price for Products. All Products Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Price specified in Exhibit D; provided, however, that if the RECs fail to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit and Buyer does not purchase the RECs pursuant to Section 4.1(b), then all Energy Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Adjusted Price specified in Exhibit D. Other than the (i) payment for the Products under this Section 5.1, (ii) payments related to Meter testing under Section 4.6(b), (iii) payments related to Meter malfunctions under Section 4.6(e), (iv) payment for Energy and RECs during the Test Period in accordance with Section 4.8, (v) payment of any Resale Damages under Section 4.4, (vi) payment of interest on late payments under Section 5.3, (vii) payments for reimbursement of Buyer's Taxes under Section 5.4(a), (viii) return of any Credit Support under Section 6.3, and (ix) payment of any Termination Payment due from Buyer under Section 9.3, Buyer shall not be required to make any other payments to Seller under this Agreement, and Seller shall be solely responsible for all costs incurred by it in connection with the performance of its obligations under this Agreement.

5.2 Payment and Netting.

(a) Billing Period. The calendar month shall be the standard period for all payments under this Agreement. On or before the fifteenth (15th) day following the end of each month, Seller shall render to Buyer an invoice for the payment obligations incurred hereunder during the preceding month, based on the Energy Delivered in the preceding month, and any RECs deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing in the preceding month. Such invoice shall contain supporting detail for all charges reflected on the invoice, and Seller shall provide Buyer with additional supporting documentation and information as Buyer may request.

(b) Timeliness of Payment. All undisputed charges shall be due and payable in accordance with each Party's invoice instructions on or before the later of (x) fifteen (15) days from receipt of the applicable invoice or (y) the last day of the calendar month in which the applicable invoice was received (or in either event the next Business Day if such day is not a

Business Day). Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any undisputed amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Late Payment Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

(c) Disputes and Adjustments of Invoices.

(i) All invoices rendered under this Agreement shall be subject to adjustment after the end of each month in order to true-up charges based on changes resulting from recent ISO-NE billing statements or revisions, if any, to previous ISO-NE billing statements. If ISO-NE resettles any invoice which relates to the Products sold under this Agreement and (a) any charges thereunder are the responsibility of the other Party under this Agreement or (b) any credits issued thereunder would be due to the other Party under this Agreement, then the Party receiving the invoice from ISO-NE shall in the case of (a) above invoice the other Party or in the case of (b) above pay the amount due to the other Party. Any invoices issued or amounts due pursuant to this Section shall be invoiced or paid as provided in this Section 5.2.

(ii) A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice rendered under this Agreement, or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the dispute given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment or refund shall be made within ten (10) days of such resolution along with interest accrued at the Late Payment Rate from and including the due date (or in the case of a refund, the payment date) but excluding the date paid. Inadvertent overpayments shall be reimbursed or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Late Payment Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment, as directed by the other Party. Any dispute with respect to an invoice or claim to additional payment is waived unless the other Party is notified in accordance with this Section 5.2 within the referenced twelve (12) month period.

(d) Netting of Payments. The Parties hereby agree that they may discharge mutual debts and payment obligations due and owing to each other under this Agreement on the same date through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Agreement, including any related damages calculated pursuant to this Agreement, interest, and payments or credits, may be netted so that only the excess amount remaining due shall be paid by the Party who owes it. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, such Party shall pay such sum in full when due. The Parties agree to provide each other with reasonable detail of such net payment or net payment request.

5.3 Interest on Late Payment or Refund. A late payment charge shall accrue on any late payment or refund as specified above at the lesser of (a) the prime rate specified in the "Money Rates" section of The Wall Street Journal (or, if such rate is not published therein, in a successor index mutually selected by the Parties) plus 1% per cent, and (b) the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties (the **"Late Payment Rate"**).

5.4 Taxes, Fees and Levies.

(a) Seller shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with the Facility or delivery or sale of the Products ("**Seller's Taxes**"). Buyer shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with such Products after Delivery of such Products to Buyer or imposed on or associated with the purchase of such Products (other than ad valorem, franchise or income taxes which are related to the sale of the Products and are, therefore, the responsibility of Seller) ("**Buyer's Taxes**"). In the event Seller shall be required by law or regulation to remit or pay any Buyer's Taxes, Buyer shall reimburse Seller for such payment. In the event Buyer shall be required by law or regulation to remit or pay any Seller's Taxes, Seller shall reimburse Buyer for such payment, and Buyer may deduct any of the amount of any such Seller's Taxes from the amount due to Seller under Section 5.2. Buyer shall have the right to all credits, deductions and other benefits associated with taxes paid by Buyer or reimbursed to Seller by Buyer as described herein. Nothing shall obligate or cause a Party to pay or be liable to pay any taxes, fees and levies for which it is exempt under law.

(b) Seller shall bear all risks, financial and otherwise, throughout the Term, associated with Seller's or the Facility's eligibility to receive any federal or state tax credits, to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes, or to receive any other grant or subsidy from a Governmental Entity or other Person. The obligation of the Parties hereunder, including those obligations set forth herein regarding the purchase and Price for and Seller's obligation to deliver the Products, shall be effective regardless of whether the production and/or sale of the Products from the Facility is eligible for, or receives, any federal or state tax credits, grants or other subsidies or any particular accounting, reporting or tax treatment during the Term.

6. SECURITY FOR PERFORMANCE *[NSTAR/UNITIL/WMECO VERSION]*

6.1 Seller's Support.

(a) Seller shall be required to post Credit Support in the amount of [$_________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] to secure Seller's obligations in the period between the Effective Date and the Commercial Operation Date (**"Development Period Security"**). Fifty percent (50%) of the Development Period Security shall be provided to Buyer on the Effective Date; and the remaining fifty percent (50%) of the Development Period Security shall be provided to Buyer within fifteen (15) Business Days after receipt of the Regulatory Approval. If at any time prior to the Commercial Operation Date, the amount of Development Period Security is reduced as a result of Buyer's draw upon such Development Period Security to less than the amount of Development Period Security required to be provided by Seller through the period ending fifteen (15) days after receipt of the Regulatory Approval, Seller shall replenish such Development Period Security to the amount of Development Period Security required to be provided by Seller through the period ending fifteen (15) days after receipt of the Regulatory Approval within five (5) days of that draw. Buyer shall return any undrawn amount of the Development Period Security to Seller within thirty (30) days after the later of (x) Buyer's receipt of an undisputed notice from Seller that the Commercial Operation Date has occurred or (y) Buyer's receipt of the full amount of the Operating Period Security.

(b) Beginning not later than ten (10) days following the Commercial Operation Date, Seller shall provide Buyer with Credit Support to secure Seller's obligations under this Agreement after the Commercial Operation Date through and including the date that all of Seller's obligations under this Agreement are satisfied (**"Operating Period Security"**). The Operating Period Security shall be in an amount equal to [$_________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less]. If at any time on or after the Commercial Operation Date, the amount of Operating Period Security is reduced as a result of Buyer's draw upon such Operating Period Security, Seller shall replenish such Operating Period Security to the total amount required under this Section 6.1(b) within five (5) Business Days of that draw.

6.2 Cash Deposits. Any cash provided by Seller as Credit Support under this Agreement shall be held in an interest bearing deposit account selected by Buyer in its reasonable discretion. All interest accrued on that cash deposit shall be retained in that account; provided, however, that to the extent the amount held in that account exceeds the required level of Development Period Security (before and on the Commercial Operation Date) or the Operating Period Security (after the Commercial Operation Date), such excess shall be paid to Seller promptly after Seller requests such a payment in writing delivered to Buyer. Seller agrees to comply with the commercially reasonable requirements of Buyer in connection with the receipt and retention of any cash provided as Credit Support under this Agreement.

6.3 Return of Credit Support. Any unused Credit Support provided under this Agreement shall be returned to the Party providing that Credit Support only after any such Credit Support has been used to satisfy any outstanding obligations of that Party in existence at the time of the expiration or termination of this Agreement. Provided such obligations have been satisfied, such Credit Support shall be returned to the Party providing it within thirty (30) days after the earlier of (a) the expiration of the Term of this Agreement or (b) termination of this Agreement under Section 8.3, Section 9.3(b) or Section 10.1(c).

6. SECURITY FOR PERFORMANCE *[NATIONAL GRID VERSION]*

6.1 Grant of Security Interest. Subject to the terms and conditions of this Agreement, Seller hereby pledges to Buyer as security for all outstanding obligations under this Agreement (other than indemnification obligations surviving the expiration of the Term) and any other documents, instruments or agreements executed in connection therewith (collectively, the **"Obligations"**), and grants to Buyer a first priority continuing security interest, lien on, and right of set-off against all Posted Collateral delivered to or received by Buyer hereunder. Upon the return by Buyer to Seller of any Posted Collateral, the security interest and lien granted hereunder on that Posted Collateral will be released immediately and, to the extent possible, without further action by either Party.

6.2 Seller's Support.

(a) Seller shall be required to post Credit Support in the amount of $[________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] to secure Seller's Obligations until the Commercial Operation Date (**"Development Period Security"**). Fifty percent (50%) of the Development Period Security shall be provided to Buyer on the Effective Date, and the remaining fifty percent (50%) of the Development Period Security shall be provided to Buyer within fifteen (15) days after the receipt of the Regulatory Approval. Buyer shall return any undrawn amount of the Development Period Security to Seller within thirty (30) days after the later of (x) Buyer's receipt of an undisputed notice from Seller that the Commercial Operation Date has occurred or (y) Buyer's receipt of the full amount of the Operating Period Security.

(b) Beginning not later than three (3) days following the Commercial Operation Date, Seller shall provide Buyer with Credit Support to secure Seller's Obligations after the Commercial Operation Date through and including the date that all of Seller's Obligations are satisfied ("**Operating Period Security**"). The Operating Period Security shall be in the amount of $[_______] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less].

(c) The Credit Support Delivery Amount, as defined below, will be rounded up, and the Return Amount, as defined below, will be rounded down, in each case to the nearest integral multiple of $10,000 (**"Rounding Amount"**).

(d) The following items will qualify as "**Credit Support**" hereunder in the amount noted under "Valuation Percentage":

	"Valuation Percentage"
(A) Cash	100%
(B) Letters of Credit	100% unless either (i) a Letter of Credit Default shall have occurred and be continuing with respect to such Letter of Credit, or (ii) twenty (20) or fewer Business Days remain prior to the expiration of such Letter of Credit, in which cases the Valuation Percentage shall be 0%.

(e) All calculations with respect to Credit Support shall be made by the Valuation Agent as of the Valuation Time on the Valuation Date.

6.3 Delivery of Credit Support.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Buyer, and (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Buyer for which there exist any unsatisfied payment obligations with respect to Buyer, then Buyer may request, by written notice, that Seller Transfer to Buyer, or cause to be Transferred to Buyer, Credit Support for the benefit of Buyer, having a Value of at least the Collateral Requirement (**"Credit Support Delivery Amount"**). Such Credit Support shall be delivered to Buyer on the next Business Day if the request is received by the Notification Time; otherwise Credit Support is due by the close of business on the second Business Day after the request is received.

6.4 Reduction and Substitution of Posted Collateral.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Seller, (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Seller for which there exist any unsatisfied payment Obligations, and (c) the Posted Collateral posted by Seller exceeds the required Operating Period Security (rounding downwards for any fractional amount to the next interval of the Rounding Amount), then Seller may, at its sole cost, request that Buyer return Operating Period Security in the amount of such difference (**"Credit Support Return Amount"**) and Buyer shall be obligated to do so. Such Posted Collateral shall be returned to Seller by the close of business on the second Business Day after Buyer's receipt of such request. The Parties agree that if Seller has posted more than one type of Credit Support to Buyer, Seller can, in its sole discretion, select the type of Credit Support for Buyer to return;

provided, however, that Buyer shall not be required to return the specified Credit Support if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Operating Period Security.

6.5 Administration of Posted Collateral.

(a) Cash. Posted Collateral provided in the form of Cash to Buyer hereunder shall be subject to the following provisions.

(i) So long as no Event of Default has occurred and is continuing with respect to Buyer, Buyer will be entitled to either hold Cash or to appoint an agent which is a Qualified Institution (a **"Custodian"**) to hold Cash for Buyer. In the event that an Event of Default has occurred and is continuing with respect to Buyer, then the provisions of Section 6.5(a)(ii) shall not apply with respect to Buyer and Cash shall be held in a Qualified Institution in accordance with the provisions of Section 6.5(a)(iii)(B). Upon notice by Buyer to Seller of the appointment of a Custodian, Seller's Obligations to make any Transfer will be discharged by making the Transfer to that Custodian. The holding of Cash by a Custodian will be deemed to be the holding of Cash by Buyer for which the Custodian is acting. If Buyer or its Custodian fails to satisfy any conditions for holding Cash as set forth above, or if Buyer is not entitled to hold Cash at any time, then Buyer will Transfer, or cause its Custodian to Transfer, the Cash to a Qualified Institution and the Cash shall be maintained in accordance with Section 6.5(a)(iii)(B). Except as set forth in Section 6.5(c), Buyer will be liable for the acts or omissions of the Custodian to the same extent that Buyer would be held liable for its own acts or omissions.

(ii) Notwithstanding the provisions of applicable Law, if no Event of Default has occurred and is continuing with respect to Buyer and no termination date has occurred or been designated as a result of an Event of Default with respect to Buyer for which there exists any unsatisfied payment obligations with respect to Buyer, then Buyer shall have the right to sell, pledge, rehypothecate, assign, invest, use, comingle or otherwise use in its business any Cash that it holds as Posted Collateral hereunder, free from any claim or right of any nature whatsoever of Seller, including any equity or right of redemption by Seller.

(iii) Notwithstanding Section 6.5(a)(ii), if neither Buyer nor the Custodian is eligible to hold Cash pursuant to Section 6.5(a)(i) then:

(A) the provisions of Section 6.5(a)(ii) will not apply with respect to Buyer; and

(B) Buyer shall be required to Transfer (or cause to be Transferred) not later than the close of business within five (5) Business Days following the beginning of such ineligibility all Cash in its possession or held on its behalf to a Qualified Institution to be held in a segregated, safekeeping or custody account (the **"Collateral Account"**) within such Qualified Institution with the title of the account indicating that the property contained therein is being held as Cash for Buyer. The Qualified Institution shall serve as Custodian with respect to the Cash in the Collateral Account, and shall hold such Cash in accordance with the terms of this Article 6 and for the security interest of Buyer and execute such account control agreements as are necessary or applicable to perfect the security interest of Seller therein pursuant to Section 9-314 of the Uniform Commercial Code or otherwise, and subject to such security interest, for the ownership and benefit of Seller. The Qualified Institution holding the Cash will invest and reinvest or procure the investment and reinvestment of the Cash in accordance with the written instructions of Buyer, subject to the approval of such instructions by Seller (which approval shall not be unreasonably withheld). Buyer shall have no responsibility for any losses resulting from any investment or reinvestment effected in accordance with Seller's approval.

(iv) So long as no Event of Default with respect to Seller has occurred and is continuing, and no termination date has occurred or been designated for which any unsatisfied payment obligations of Seller exist as the result of an Event of Default with respect to Seller, in the event that Buyer or its Custodian is holding Cash, Buyer will Transfer (or cause to be Transferred) to Seller, in lieu of any interest or other amounts paid or deemed to have been paid with respect to such Cash (all of which shall be retained by Buyer), the Interest Amount. Interest on Cash shall accrue at the Collateral Interest Rate. Interest accrued during the previous month shall be paid by Buyer to Seller on the 3rd Business Day of each calendar month and on any Business Day that posted Credit Support in the form of Cash is returned to Seller, but solely to the extent that, after making such payment, the amount of the Posted Collateral will be at least equal to the required Development Period Security or Operating Period Security, as applicable. On or after the occurrence of an Event of Default with respect to Seller or a termination date as a result of an Event of Default with respect to Seller, Buyer or its Custodian shall retain any such Interest Amount as additional Posted Collateral hereunder until the Obligations of Seller under the Agreement have been satisfied in the case of a termination date or for so long as such Event of Default is continuing in the case of an Event of Default.

(b) Buyer's Rights and Remedies. If at any time an Event of Default with respect to Seller has occurred and is continuing, then, unless Seller has paid in full all of its Obligations that are then due, including those under Section 9.3(b) of this Agreement, Buyer may exercise one or more of the following rights and remedies: (i) all rights and remedies available to a secured party under applicable Law with respect to Posted Collateral held by Buyer, (ii) the right to set-off any amounts payable by Seller with respect to any Obligations against any Posted Collateral or the cash equivalent of any Posted Collateral held by Buyer, or (iii) the right to liquidate any Posted Collateral held by Buyer and to apply the proceeds of such liquidation of the Posted Collateral to any amounts payable to Buyer with respect to the Obligations in such order as Buyer may elect. For purposes of this Section 6.5, Buyer may draw on the undrawn portion of any Letter of Credit from time to time up to the amount of the Obligations that are due at the time of such drawing. Cash proceeds that are not applied to the Obligations shall be maintained in accordance with the terms of this Article 6. Seller shall remain liable for amounts due and owing to Buyer that remain unpaid after the application of Posted Collateral, pursuant to this Section 6.5.

(c) Seller's Rights and Remedies. If at any time a termination date has occurred or been designated as the result of an Event of Default with respect to Buyer and Buyer has provided Credit Support to Seller under Section 9.3(b), then unless Buyer has paid in full all of its obligations under Section 9.3(b) of this Agreement: (i) Seller may exercise all rights and remedies available to Seller under applicable Law with respect to any Posted Collateral provided by Buyer, (ii) Buyer will be obligated immediately to return all Posted Collateral provided by Seller, including any accrued interest to Seller, or (iii) to the extent that Posted Collateral provided by Seller, including any accrued interest, is not returned pursuant to (ii) above, Seller may set-off any amounts payable by Seller with respect to any Obligations against any posted Credit Support or the cash equivalent thereof or to the extent that Seller does not set off such amounts, withhold payment of any remaining amounts payable by Seller with respect to any obligations of Buyer, up to the value of the remaining posted Credit Support held by Buyer, until that posted Credit Support is Transferred to Seller. For avoidance of doubt, (i) Buyer will be obligated immediately to Transfer any Letter of Credit to Seller and (ii) Seller may do any one or more of the following: (x) to the extent that the Letter of Credit is not Transferred to Seller as required pursuant to (i) above, set-off any amounts payable by Seller with respect to any Obligations against any such Letter of Credit held by Buyer and, to the extent its rights to set-off are not exercised, withhold payment of any remaining amounts payable by Seller with respect to any Obligations, up to the value of any remaining posted Credit Support and the value of any Letter of Credit held by Buyer, until any such Posted Credit Support and such Letter of Credit is Transferred to Seller; and (y) exercise rights and remedies available to Seller under the terms of the Letter of Credit.

(d) Letters of Credit. Credit Support provided in the form of a Letter of Credit shall be subject to the following provisions.

(i) As one method of providing increased Credit Support, Seller may increase the amount of an outstanding Letter of Credit or establish one or more additional Letters of Credit.

(ii) Upon the occurrence of a Letter of Credit Default, Seller agrees to Transfer to Buyer either a substitute Letter of Credit or Cash, in each case on or before the first (1^{st}) Business Day after the occurrence thereof (or the third (3^{rd}) Business Day after the occurrence thereof if only clause (a) under the definition of Letter of Credit Default applies).

(iii) Notwithstanding Sections 6.3 and 6.4, (1) Buyer need not return a Letter of Credit unless the entire principal amount is required to be returned, (2) Buyer shall consent to a reduction of the principal amount of a Letter of Credit to the extent that a Credit Support Delivery Amount would not be created thereby (as of the time of the request or as of the last time the Credit Support Delivery Amount was determined), and (3) if there is more than one form of Posted Collateral when a Credit Support Return Amount is to be Transferred, the Secured Party may elect which to Transfer.

(e) <u>Care of Posted Collateral.</u> Each Party shall exercise reasonable care to assure the safe custody of all Posted Collateral to the extent required by applicable Law, and in any event a Party will be deemed to have exercised reasonable care if it exercises at least the same degree of care as it would exercise with respect to its own property. Except as specified in the preceding sentence, each Party will have no duty with respect to the Posted Collateral, including without limitation, any duty to enforce or preserve any rights thereto.

(f) <u>Substitutions.</u> Unless otherwise prohibited herein, upon notice to Buyer specifying the items of Posted Collateral to be exchanged, Seller may, on any Business Day, deliver to Buyer other Credit Support (**"<u>Substitute Credit Support</u>"**). On the Business Day following the day on which the Substitute Credit Support is delivered to Buyer, Buyer shall return to Seller the items of Credit Support specified in Seller's notice; provided, however, that Buyer shall not be required to return the specified Posted Collateral if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Development Period Security or Operating Period Security set forth in Sections 6.2(a) and 6.2(b), respectively.

6.6 <u>Exercise of Rights Against Posted Collateral</u>

(a) <u>Disputes regarding amount of Credit Support.</u> If either Party disputes the amount of Credit Support to be provided or returned (such Party the "**<u>Disputing Party</u>**"), then the Disputing Party shall (a) deliver the undisputed amount of Credit Support to the other Party (such Party, the "**<u>Requesting Party</u>**") and (b) notify the Requesting Party of the existence and nature of the dispute no later than 5:00 p.m. Eastern Prevailing Time on the Business Day that the request for Credit Support was made (the "**<u>Request Date</u>**"). On the Business Day following the Request Date, the Parties shall consult with each other in order to reconcile the two conflicting amounts. If the Parties are not able to resolve their dispute, the Credit Support shall be recalculated, on the Business Day following the Request Date, by each Party requesting quotations from two (2) Reference Market-Makers for a total of four (4) quotations. The highest and lowest of the four (4) quotations shall be discarded and the arithmetic average shall be taken of the remaining two (2), which shall be used in order to determine the amount of Credit Support required. On the same day the Credit Support amount is recalculated, the Disputing Party shall deliver any additional Credit Support required pursuant to the recalculation or the Requesting Party shall return any excess Credit Support that is no longer required pursuant to the recalculation.

(b) Further Assurances. Promptly following a request by a Party, the other Party shall use commercially reasonable efforts to execute, deliver, file, and/or record any financing statement, specific assignment, or other document and take any other action that may be necessary or desirable to create, perfect, or validate any security interest or lien, to enable the requesting party to exercise or enforce its rights or remedies under this Agreement, or to effect or document a release of a security interest on posted Credit Support or accrued interest.

(c) Further Protection. Seller will promptly give notice to Buyer of, and defend against, any suit, action, proceeding, or lien (other than a banker's lien in favor of the Custodian appointed by Buyer so long as no amount owing from Seller to such Custodian is overdue) that involves the Posted Collateral delivered to Buyer by Seller or that could adversely affect any security interest or lien granted pursuant to this Agreement.

7. REPRESENTATIONS, WARRANTIES, COVENANTS AND ACKNOWLEDGEMENTS

7.1 Representations and Warranties of Buyer. Buyer hereby represents and warrants to Seller as follows:

(a) Organization and Good Standing; Power and Authority. Buyer is a corporation duly incorporated, validly existing and in good standing under the laws of Massachusetts. Subject to the receipt of the Regulatory Approval, Buyer has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Due Authorization; No Conflicts. The execution and delivery by Buyer of this Agreement, and the performance by Buyer of its obligations hereunder, have been duly authorized by all necessary actions on the part of Buyer and do not and, under existing facts and Law, shall not: (i) contravene its certificate of incorporation or any other governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) assuming receipt of the Regulatory Approvals, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing.

(c) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Buyer and, assuming the due execution hereof and performance hereunder by Seller and receipt of the Regulatory Approval, constitutes a legal, valid and binding obligation of Buyer, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(d) No Proceedings. Except to the extent relating to the Regulatory Approval, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Buyer or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Buyer reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Buyer's ability to perform its obligations under this Agreement.

(e) Consents and Approvals. Except to the extent associated with the Regulatory Approval, the execution, delivery and performance by Buyer of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken or that shall be duly obtained, made or taken on or prior to the date required, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable as required under applicable Law.

(f) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Buyer.

(g) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Buyer, or, to Buyer's knowledge, threatened against it.

(h) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Buyer of its obligations under this Agreement.

7.2 Representations and Warranties of Seller. Seller hereby represents and warrants to Buyer as of the Effective Date as follows:

(a) Organization and Good Standing; Power and Authority. Seller is a [______________], validly existing and in good standing under the laws of [___________]. Subject to the receipt of the Permits listed in Exhibit B, Seller has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Authority. Seller (i) has the power and authority to own and operate its businesses and properties, to own or lease the property it occupies and to conduct the business in which it is currently engaged; (ii) is duly qualified and in good standing under the laws of each jurisdiction where its ownership, lease or operation of property or the conduct of its business requires such qualification; and (iii) holds, as of the Effective Date, or shall hold by the

Commercial Operation Date, all rights and entitlements necessary to construct, own and operate the Facility and to deliver the Products to the Buyer in accordance with this Agreement.

(c) Due Authorization; No Conflicts. The execution and delivery by Seller of this Agreement, and the performance by Seller of its obligations hereunder, have been duly authorized by all necessary actions on the part of Seller and do not and, under existing facts and Law, shall not: (i) contravene any of its governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) assuming receipt of the Permits listed on Exhibit B, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing.

(d) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Seller and, assuming the due execution hereof and performance hereunder by Seller and receipt of the Permits listed on Exhibit B, constitutes a legal, valid and binding obligation of Seller, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(e) No Proceedings. Except to the extent associated with the Permits listed on Exhibit B, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Seller or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Seller reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Seller's ability to perform its obligations under this Agreement.

(f) Consents and Approvals. Subject to the receipt of the Permits listed on Exhibit B on or prior to the date such Permits are required under applicable Law, the execution, delivery and performance by Seller of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable. To Seller's knowledge, Seller shall be able to receive the Permits listed in Exhibit B in due course and as required under applicable Law to the extent that those Permits have not previously been received.

(g) New RPS Class I Renewable Generation Unit. The Facility shall be an RPS Class I Renewable Generation Unit, qualified by the DOER as eligible to participate in the RPS program, under Section 11F of Chapter 25A (subject to Section 4.7(b) in the event of a change in Law affecting such qualification as a RPS Class I Renewable Generation Unit) and shall have a commercial operation date, as verified by the DOER, on or after January 1, 2013.

(h) Title to Products. Seller has and shall have good and marketable title to all Products sold and Delivered to Buyer under this Agreement, free and clear of all liens, charges and encumbrances. Seller has not sold and shall not sell any such Products to any other Person, and no Person other than Seller can claim an interest in any Product to be sold to Buyer under this Agreement.

(i) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Seller.

(j) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Seller, or, to Seller's knowledge, threatened against it.

(k) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Seller of its obligations under this Agreement.

7.3 Continuing Nature of Representations and Warranties. The representations and warranties set forth in this Section are made as of the Effective Date and deemed made continually throughout the Term. If at any time during the Term, any Party obtains actual knowledge of any event or information which causes any of the representations and warranties in this Article 7 to be materially untrue or misleading, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

8. REGULATORY APPROVAL

8.1 Receipt of Regulatory Approval. The obligations of the Parties to perform this Agreement, other than the Parties' obligations under Section 6.1, Section 6.2, Section 8.2, Section 8.3 and Section 12, are conditioned upon and shall not become effective or binding until the receipt of the Regulatory Approval. Buyer shall notify Seller within five (5) Business Days after receipt of the Regulatory Approval or receipt of an order of the MDPU regarding this Agreement that is not acceptable in form and substance to Buyer in its sole discretion.

8.2 Filing for Regulatory Approval. Buyer shall use commercially reasonable efforts to (i) file an application for the Regulatory Approval with the MDPU by not later than [________] [30 days from Effective Date] and (ii) at Buyer's sole discretion, exercise commercially reasonable efforts to obtain the Regulatory Approval, including using commercially reasonable efforts to obtain a favorable resolution in any appeal of an order of the MDPU with respect to this Agreement; provided that Buyer shall have no obligation to appeal a MDPU order that it determines is unacceptable. Seller shall have the right to intervene in the proceeding before the MDPU and shall use commercially reasonable efforts to cooperate with Buyer (but only as requested by Buyer) in obtaining the Regulatory Approval.

8.3 Failure to Obtain Regulatory Approval. If Buyer (i) on any date notifies Seller that it has received an order of the MDPU regarding this Agreement that is not acceptable in form and substance to Buyer in its sole discretion or (ii) has not notified Seller that it has received the Regulatory Approval by [_______] [300 days from Effective Date], either Party may terminate this Agreement within thirty (30) days after such date by delivery of written notice to the other Party in accordance with Section 17. Upon such termination, neither Party shall have any further liability hereunder except for any obligations arising under Sections 6.3 and 12 which accrued prior to such termination.

9. BREACHES; REMEDIES

9.1 Events of Default by Either Party. It shall constitute an event of default (**"Event of Default"**) by either Party hereunder if:

(a) Representation or Warranty. Any material breach of any representation or warranty of such Party set forth herein, or in filings or reports made pursuant to this Agreement, and such breach continues for more than thirty (30) days after the Non-Defaulting Party has provided written notice to the Defaulting Party that any material representation or warranty set forth herein is false, misleading or erroneous in any material respect without the breach having been cured; or

(b) Payment Obligations. Any undisputed payment due and payable hereunder is not made on the date due, and such failure continues for more than ten (10) Business Days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; or

(c) Other Covenants. Other than a Delivery Failure (the sole remedy for which shall be the payment of Cover Damages under Section 4.3), a Rejected Purchase (the sole remedy for which shall be the payment of Resale Damages under 4.4), or an Event of Default described in Section 9.1(a), 9.1(b), 9.1(d), 9.1(e) or 9.2, such Party fails to perform, observe or otherwise to comply with any obligation hereunder and such failure continues for more than thirty (30) days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; provided, however, that such period shall be extended for an additional reasonable period if the Defaulting Party is unable to cure within that thirty (30) day period and provided that corrective action has been taken by the Defaulting Party within such thirty (30) day period and so long as such cure is diligently pursued by the Defaulting Party until such Default had been corrected, but in any event within one hundred fifty (150) days; or

(d) Bankruptcy. Such Party (i) is adjudged bankrupt or files a petition in voluntary bankruptcy under any provision of any bankruptcy law or consents to the filing of any bankruptcy or reorganization petition against such Party under any such law, or (without limiting the generality of the foregoing) files a petition to reorganize pursuant to 11 U.S.C. § 101 or any similar statute applicable to such Party, as now or hereinafter in effect, (ii) makes an assignment for the benefit of creditors, or admits in writing an inability to pay its debts generally as they become due, or consents to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of such Party, or (iii) is subject to an order of a court of competent jurisdiction appointing a receiver or liquidator or custodian or trustee of such Party or of a major part of such Party's property, which is not dismissed within sixty (60) days; or

(e) Permit Compliance. Such Party fails to obtain and maintain in full force and effect any Permit (other than the Regulatory Approval) necessary for such Party to perform its obligations under this Agreement.

9.2 Events of Default by Seller. In addition to the Events of Default described in Section 9.1, it shall constitute an Event of Default by Seller hereunder if:

(a) Taking of Facility Assets. Any asset of Seller that is material to the construction, operation or maintenance of the Facility or the performance of its obligations hereunder is taken upon execution or by other process of law directed against Seller, or any such asset is taken upon or subject to any attachment by any creditor of or claimant against Seller and such attachment is not disposed of within sixty (60) days after such attachment is levied; or

(b) Failure to Maintain Credit Support. The failure of Seller to provide, maintain and/or replenish the Development Period Security or the Operating Period Security as required pursuant to Article 6 of this Agreement, and such failure continues for more than five (5) Business Days after Buyer has provided written notice thereof to Seller; or

(c) Energy Output. The failure of the Facility to produce Energy for twenty-four (24) consecutive months during the Services Term for any reason, including due in whole or in part to a Force Majeure; or

(d) Failure to Satisfy ISO-NE Obligations. The failure of Seller to satisfy, or cause to be satisfied (other than by Buyer), any material obligation under the ISO-NE Rules or ISO-NE Practices or any other material obligation with respect to ISO-NE, and such failure has a material adverse effect on the Facility or Seller's ability to perform its obligations under this Agreement or on Buyer or Buyer's ability to receive the benefits under this Agreement, provided that if Seller's failure to satisfy any material obligation under the ISO-NE Rules or ISO-NE Practices does not have a material adverse effect on Buyer or Buyer's ability to receive the benefits under this Agreement, Seller may cure such failure within thirty (30) days of its occurrence; or

(e) Failure to Meet Critical Milestones. The failure of Seller to satisfy any Critical Milestone by the date set forth therefor in Section 3.1(a), as the same may be extended in accordance with Section 3.1(c).

9.3 Remedies.

(a) Suspension of Performance and Remedies at Law. Upon the occurrence and during the continuance of an Event of Default, the Non-Defaulting Party shall have the right, but not the obligation, to (i) withhold any payments due the Defaulting Party under this Agreement, (ii) suspend its performance hereunder, and (iii) exercise such other remedies as provided for in this Agreement or, to the extent not inconsistent with the terms of this Agreement, at law, including, without limitation, the termination right set forth in Section 9.3(b). In addition to the foregoing, the Non-Defaulting Party shall retain its right of specific performance to enforce the Defaulting Party's obligations under this Agreement.

(b) Termination and Termination Payment. Upon the occurrence of an Event of Default, a Non-Defaulting Party may terminate this Agreement at its sole discretion by providing written notice of such termination to the Defaulting Party. If the Non-Defaulting Party terminates this Agreement, it shall be entitled to calculate and receive as its sole remedy for such Event of Default a **"Termination Payment"** as follows:

(i) *Termination by Buyer Prior to Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring prior to the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the sum of (x) all Delay Damages due and owing by Seller through the date of such termination plus (y) the undrawn amount of any Development Period Security provided to Buyer by Seller.

(ii) *Termination by Seller Prior to Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer prior to the Commercial Operation Date, Seller shall only receive a Termination Payment if the Commercial Operation Date either occurs by the date set forth therefor in Section 3.1(a) (as the same may be extended in accordance with Section 3.1(c)) or would have occurred by such date but for the Event of Default by Buyer giving rise to the termination of this Agreement. In such case, (x) if Seller terminates this Agreement because of an Event of Default by Buyer prior to the Financial Closing Date, the Termination Payment due to Seller shall be equal to the lesser of: (i) all of Seller's out-of-pocket expenses incurred in connection with the development and construction of the Facility prior to such termination and (ii) the Termination Payment due to Seller shall be calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller; and (y) if Seller terminates this Agreement because of an Event of Default by Buyer on or after the Financial Closing Date, the Termination Payment due to Seller shall be calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller.

(iii) *Termination by Buyer On or After Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring on or after the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the amount, if positive, calculated according to the following formula:

(x) the present value, discounted at a rate equal to the prime rate specified in the "Money Rates" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (i) the amount, if, any, by which the forward market price of Energy and Renewable Energy Credits, as determined by the average of the quotes of at least two nationally recognized energy consulting firms chosen by Buyer, for Replacement Energy and Replacement RECs, exceeds the applicable Price that would have been paid pursuant to Exhibit D of this Agreement, multiplied by (ii) the projected Energy output of the Facility as determined by a recognized third party expert selected by Buyer, using a probability of exceedance basis of 50%; plus, (y) any reasonable incidental costs incurred by Buyer as a result of the Event of Default and termination of the Agreement

All such amounts shall be determined by Buyer in good faith and in a commercially reasonable manner, and Buyer shall provide Seller with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iii).

(iv) *Termination by Seller On or After Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer occurring on or after the Commercial Operation Date, the Termination Payment due to Seller shall be equal to the amount, if positive, calculated according to the following formula:

(x) the present value, discounted at a rate equal to the prime rate specified in the "Money Rates" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (i) the amount, if, any, by which the applicable Price that would have been paid pursuant to Exhibit D of this Agreement, exceeds the forward market price of energy and Renewable Energy Credits as determined by the average of the quotes of at least two nationally recognized energy consulting firms chosen by Seller, for Replacement Energy and Replacement RECs, multiplied by (ii) the projected Energy output of the Facility as determined by a recognized third party expert selected by Seller using a probability of exceedance basis of 50%; plus, (y) any reasonable incidental costs incurred by Seller as a result of the Event of Default and termination of the Agreement.

All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Seller shall provide Buyer with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iv).

(v) *Acceptability of Liquidated Damages*. Each Party agrees and acknowledges that (i) the damages that the Parties would incur due to an Event of Default would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Termination Payment as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

(vi) *Payment of Termination Payment*. The Defaulting Party shall make the Termination Payment within ten (10) Business Days after such notice is effective. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within ten (10) Business Days of receipt of the calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, the Defaulting Party shall first transfer Credit Support to the Non-Defaulting Party in an amount equal to the Termination Payment as calculated by the Non-Defaulting Party. If the Parties are unable to resolve the dispute within thirty (30) days, Article 11 shall apply.

(vii) *Use and Return of Credit Support*. In the event that the Defaulting Party fails to pay the Termination Payment in full within the time period set forth in Section 9.3(b)(vii), the Non-Defaulting Party may draw upon any Credit Support provided by the Defaulting Party to satisfy the unpaid portion of the Termination Payment. Upon the payment of the Termination Payment in full, any undrawn Credit Support shall be promptly returned to each Party providing that Credit Support.

(viii) *Reinstatement of Agreement*. In the event that Buyer terminates this Agreement prior to the Commercial Operation Date pursuant to Section 9.3(b)(i) and Seller thereafter achieves the Commercial Operation Date within one (1) year after such termination, Buyer may elect to reinstate this Agreement in accordance with its terms by providing Seller with at least six (6) months' prior written notice of such reinstatement. Upon such reinstatement, Buyer shall return to Seller any Termination Payment made by Seller, together with interest accruing at the Late Payment Rate, on or prior to the date selected for reinstatement of this Agreement.

(c) Set-off. The Non-Defaulting Party shall be entitled, at its option and in its discretion, to withhold and set off any amounts owed by the Non-Defaulting Party to the Defaulting Party against any payments and any other amounts owed by the Defaulting Party to the Non-Defaulting Party, including any Termination Payment payable as a result of any early termination of this Agreement.

(d) Notice to Lenders. Buyer shall provide a copy of any notice given to Seller under this Section 9 to one, but not more than one, Lender of which Buyer shall have written notice, and Buyer shall afford such Lender the same opportunities to cure Events of Default under this Agreement as are provided to Seller hereunder.

(e) Limitation of Remedies, Liability and Damages. EXCEPT AS EXPRESSLY SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS

INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

10. FORCE MAJEURE

10.1 Force Majeure.

(a) The term **"Force Majeure"** means an unusual, unexpected and significant event: (i) that was not within the control of the Party claiming its occurrence; (ii) that could not have been prevented or avoided by such Party through the exercise of reasonable diligence; and (iii) that directly prohibits or prevents such Party from performing its obligations under this Agreement. Under no circumstances shall Force Majeure include (w) any occurrence or event that merely increases the costs or causes an economic hardship to a Party, (x) any occurrence or event that was caused by or contributed to by the Party claiming the Force Majeure, (y) Seller's ability to sell the Products at a price greater than that set out in this Agreement, or (z) Buyer's ability to procure the Products at a price lower than that set out in this Agreement. In addition, a delay or inability to perform attributable to a Party's lack of preparation, a Party's failure to timely obtain and maintain all necessary Permits (excepting the Regulatory Approval), a failure to satisfy contractual conditions or commitments, or lack of or deficiency in funding or other resources shall each not constitute a Force Majeure.

(b) If either Party is unable, wholly or in part, by Force Majeure to perform obligations under this Agreement, such performance shall be excused and suspended so long as the circumstances that give rise to such inability exist, but for no longer period. The Party whose performance is affected shall give prompt notice thereof; such notice may be given orally or in writing but, if given orally, it shall be promptly confirmed in writing, providing details regarding the nature, extent and expected duration of the Force Majeure, its anticipated effect on the ability of such Party to perform obligations under this Agreement, and the estimated duration of any interruption in service or other adverse effects resulting from such Force Majeure, and shall be updated or supplemented to keep the other Party advised of the effect and remedial measures being undertaken to overcome the Force Majeure. Such inability shall be promptly corrected to the extent it may be corrected through the exercise of due diligence. Neither party shall be liable for any losses or damages arising out of a suspension of performance that occurs because of Force Majeure.

(c) Notwithstanding the foregoing, if the Force Majeure prevents full or partial performance under this Agreement for a period of twelve (12) months or more, the Party whose performance is not prevented by Force Majeure shall have the right to terminate this Agreement upon written notice to the other Party and without further recourse.

(d) Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Energy to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in Section 10.1(a) has occurred.

11. DISPUTE RESOLUTION

11.1 Dispute Resolution. In the event of any dispute, controversy or claim between the Parties arising out of or relating to this Agreement (collectively, a **"Dispute"**), the Parties shall attempt in the first instance to resolve such Dispute through consultations between the Parties. If such consultations do not result in a resolution of the Dispute within fifteen (15) days after notice of the Dispute has been delivered to either Party, then such Dispute shall be referred to the senior management of the Parties for resolution. If the Dispute has not been resolved within fifteen (15) days after such referral to the senior management of the Parties, then the Parties may seek to resolve such Dispute in the courts of the Commonwealth of Massachusetts; provided, however, if the Dispute is subject to FERC's jurisdiction over wholesale power contracts, then either Party may elect to proceed with the mediation through the FERC's Dispute Resolution Service; provided, however, that if one Party fails to participate in the negotiations as provided in this Section 11.1, the other Party can initiate mediation prior to the expiration of the thirty (30) Business Days. Unless otherwise agreed, the Parties will select a mediator from the FERC panel. The procedure specified herein shall be the sole and exclusive procedure for the resolution of Disputes. To the fullest extent permitted by law, any mediation proceeding and the settlement shall be maintained in confidence by the Parties.

11.2 Allocation of Dispute Costs. The fees and expenses associated with mediation shall be divided equally between the Parties, and each Party shall be responsible for its own legal fees, including but not limited to attorney fees, associated with any Dispute. The Parties may, by written agreement signed by both Parties, alter any time deadline, location(s) for meeting(s), or procedure outlined herein or in the FERC's rules for mediation.

11.3 Consent to Jurisdiction. Subject to Section 11.1, the Parties agree to the exclusive jurisdiction of the state and federal courts located in the Commonwealth of Massachusetts for any legal proceedings that may be brought by a Party arising out of or in connection with any Dispute.

11.4 Waiver of Jury Trial. EACH PARTY HEREBY WAIVES TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR PROCEEDING ARISING OUT OF, RESULTING FROM OR IN ANY WAY RELATING TO THIS AGREEMENT

12. CONFIDENTIALITY

12.1 Nondisclosure. Buyer and Seller each agrees not to disclose to any Person and to keep confidential, and to cause and instruct its Affiliates, officers, directors, employees, partners and representatives not to disclose to any Person and to keep confidential, any non-public information relating to the terms and provisions of this Agreement, and any information relating to the Products to be supplied by Seller hereunder, and such other non-public information that is designated as "Confidential." Notwithstanding the foregoing, any such information may be disclosed:

(a) to the extent Buyer determines it is appropriate in connection with efforts to obtain or maintain the Regulatory Approval or to seek rate recovery for amounts expended by Buyer under this Agreement;

(b) as required by applicable laws, regulations, rules or orders or by any subpoena or similar legal process of any Governmental Entity so long as the receiving Party gives the non-disclosing Party written notice at least three (3) Business Days prior to such disclosure, if practicable;

(c) to the Affiliates of either Party and to the consultants, attorneys, auditors, financial advisors, lenders or potential lenders and their advisors of either Party or their Affiliates, but solely to the extent they have a need to know that information;

(d) in order to comply with any rule or regulation of ISO-NE, any stock exchange or similar Person or for financial disclosure purposes;

(e) to the extent the non-disclosing Party shall have consented in writing prior to any such disclosure; and

(f) to the extent that the information was previously made publicly available other than as a result of a breach of this Section 12.1;

provided, however, in each case, that the Party seeking such disclosure shall, to the extent practicable, use commercially reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce or seek relief in connection with this Section 12.1.

12.2 Public Statements. No public statement, press release or other voluntary publication regarding this Agreement or the transactions to be made hereunder shall be made or issued without the prior consent of the other Party.

13. INDEMNIFICATION

Seller shall indemnify, defend and hold Buyer and its partners, shareholders, directors, officers, employees and agents (including, but not limited to, Affiliates and contractors and their employees), harmless from and against all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever arising from or related to Seller's execution, delivery or performance of this Agreement, or Seller's negligence, gross negligence, or willful misconduct, or Seller's failure to satisfy any obligation or liability under this Agreement. Buyer shall not indemnify, defend or hold harmless Seller or its partners, members, shareholders, directors, officers, managers employees or agents from and against any liabilities, damages, losses, penalties, claims, demands, suits or proceedings claimed by, due to or instituted by any third party as a result of either Party's execution, delivery or performance of this Agreement.

14. ASSIGNMENT AND CHANGE OF CONTROL

14.1 Prohibition on Assignments. Except as permitted under this Section 14, this Agreement may not be assigned by either Party without the prior written consent of the other Party, which consent may not be unreasonably withheld, conditioned or delayed. When assignable, this Agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assignees of the Parties, except that no assignment, pledge or other transfer of this Agreement by either Party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement unless the other Party (or its successors or assigns) consents in writing to the assignment, pledge or other transfer and expressly releases the assignor, pledgor, or transferor from its obligations thereunder.

14.2 Permitted Assignment by Seller. Seller may pledge or assign the Facility, this Agreement or the revenues under this Agreement to any Lender as security for the project financing of the Facility, subject to Buyer's execution of a consent to assignment that is in form and substance reasonably satisfactory to Seller and such Lender that incorporates terms and conditions customary for a transaction of this type (including the provisions included in Section 9.3(d)); provided, however, that Buyer shall not be obligated to enter into any consent which shall adversely affect Buyer's rights or obligations under this Agreement. Buyer shall not unreasonably withhold, condition or delay providing its consent to an assignment to a Lender.

14.3 Change in Control over Seller. Buyer's consent shall be required for any change in Control over Seller, which consent shall not be unreasonably withheld, conditioned or delayed and shall be provided if Buyer reasonably determines that such change in Control does not have a material adverse effect on Seller's creditworthiness or Seller's ability to perform its obligations under this Agreement.

14.4 Permitted Assignment by Buyer. Buyer shall have the right to assign this Agreement without consent of Seller (a) in connection with any merger or consolidation of the Buyer with or into another Person or any exchange of all of the common stock or other equity interests of Buyer or Buyer's parent for cash, securities or other property or any acquisition, reorganization, or other similar corporate transaction involving all or substantially all of the common stock or other equity interests in, or assets of, Buyer, or (b) to any substitute purchaser of the Products so long as in the case of either clause (a) or clause (b) of this Section 14.4, either (1) the proposed assignee's credit rating is at least either BBB- from S&P or Baa3 from Moody's or (2) the proposed assignee's credit rating is equal to or better than that of Buyer at the time of the proposed assignment, or (3) such assignment, or in the case of clause (a) above the transaction associated with such assignment, has been approved by the MDPU.

14.5 Prohibited Assignments. Any purported assignment of this Agreement not in compliance with the provisions of this Section 14 shall be null and void.

15. TITLE; RISK OF LOSS

Title to and risk of loss related to Buyer's Percentage Entitlement of the Energy shall transfer from Seller to Buyer at the Delivery Point. Title and risk of loss related to Buyer's Percentage Entitlement of the RECs shall transfer to Buyer when the same are credited to

Buyer's GIS account(s) or the GIS account(s) designated by Buyer to Seller in writing. Seller warrants that it shall deliver to Buyer the Products free and clear of all claims therein or thereto by any Person.

16. AUDIT

16.1 Audit. Each Party shall have the right, upon reasonable advance notice, and at its sole expense (unless the other Party has defaulted under this Agreement, in which case the Defaulting Party shall bear the expense) and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party statements evidencing the quantities of Products delivered or provided hereunder. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof shall be made promptly and shall bear interest at the Late Payment Rate from the date the overpayment or underpayment was made until paid.

16.2 Consolidation of Financial Information. The Parties agree that generally accepted accounting principles and U.S. Securities and Exchange Commission rules require Buyer to evaluate whether Buyer must consolidate Seller's financial information on Buyer's financial statements. Buyer shall require access to financial records and personnel to determine if consolidated financial reporting is required. If Buyer determines at any time that such consolidation is required, Buyer shall require the following from Seller within fifteen (15) days after the end of every calendar quarter for the Term of this Agreement:

(a) complete financial statements and notes to financial statements for such quarter;

(b) financial schedules underlying such financial statements; and

(c) access to records and personnel to enable Buyer's independent auditor to conduct financial audits (in accordance with generally accepted auditing standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002). Any information provided to Buyer under this Section 16.2 shall be treated as confidential except that such information may be disclosed for financial statement purposes.

17. NOTICES

Any notice or communication given pursuant hereto shall be in writing and (1) delivered personally (personally delivered notices shall be deemed given upon written acknowledgment of receipt after delivery to the address specified or upon refusal of receipt); (2) mailed by registered or certified mail, postage prepaid (mailed notices shall be deemed given on the actual date of delivery, as set forth in the return receipt, or upon refusal of receipt); or (3) delivered by fax or electronic mail (notices sent by fax or electronic mail shall be deemed given upon confirmation of delivery); in each case addressed as follows or to such other addresses as may hereafter be designated by either Party to the other in writing:

If to Buyer: [ ]

With a copy to: [ ]

If to Seller: [ ]

With a copy to: [ ]

18. WAIVER AND MODIFICATION

This Agreement may be amended and its provisions and the effects thereof waived only by a writing executed by the Parties, and no subsequent conduct of any Party or course of dealings between the Parties shall effect or be deemed to effect any such amendment or waiver. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided. The failure of either Party to enforce any provision of this Agreement shall not be construed as a waiver of or acquiescence in or to such provision. Buyer shall determine in its sole discretion whether any amendment or waiver of the provisions of this Agreement shall require MDPU approval or filing, and if Buyer determines that MDPU approval or filing is required for any amendment or waiver of the provisions of this Agreement, then such amendment or waiver shall not become effective unless and until such MDPU approval is obtained or such MDPU filing is made.

19. INTERPRETATION

19.1 <u>Choice of Law</u>. Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the Commonwealth of Massachusetts (without regard to its principles of conflicts of law).

19.2 <u>Headings</u>. Article and Section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and exhibits are, unless the context otherwise requires, references to articles, sections and exhibits of this Agreement. The words “hereof” and “hereunder” shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

19.3 <u>Forward Contract; Commodities Exchange Act</u>. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereunder are a “forward contract” within the meaning of the United States Bankruptcy Code. Each Party represents and warrants, solely as to itself, that it is (i) a “forward merchant” within the meaning of the United States Bankruptcy Code and (ii) an “eligible commercial entity” and an “eligible contract participant” within the meaning of the United States Commodities Exchange Act.

19.4 <u>Standard of Review</u>. The Parties acknowledge and agree that the standard of review for any avoidance, breach, rejection, termination or other cessation of performance of or changes to any portion of this integrated, non-severable Agreement (as described in Section 22) over which FERC has jurisdiction, whether proposed by Seller, by Buyer, by a non-party of, by FERC acting *sua sponte* shall be the “public interest” standard of review set forth in <u>United Gas</u>

Pipe Line Co. v. Mobile Gas Serv. Co., 350 U.S. 332 (1956) and Federal Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348 (1956). Each Party agrees that if it seeks to amend any applicable power sales tariff during the Term, such amendment shall not in any way materially and adversely affect this Agreement without the prior written consent of the other Party. Each Party further agrees that it shall not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement.

19.5 Change in ISO-NE Rules and Practices. This Agreement is subject to the ISO-NE Rules and ISO-NE Practices. If, during the Term of this Agreement, any ISO-NE Rule or ISO-NE Practice is terminated, modified or amended or is otherwise no longer applicable, resulting in a material alteration of a material right or obligation of a Party hereunder, the Parties agree to negotiate in good faith in an attempt to amend or clarify this Agreement to embody the Parties' original intent regarding their respective rights and obligations under this Agreement, provided that neither Party shall have any obligation to agree to any particular amendment or clarification of this Agreement. The intent of the Parties is that any such amendment or clarification reflect, as closely as possible, the intent, substance and effect of the ISO-NE Rule or ISO-NE Practice being replaced, modified, amended or made inapplicable as such ISO-NE Rule or ISO-NE Practice was in effect prior to such termination, modification, amendment, or inapplicability, provided that such amendment or clarification shall not in any event alter (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

19.6 Change in Law or Buyer's Accounting Treatment. If, during the Term of this Agreement, there is a change in Law or accounting standards or rules or a change in the interpretation of applicability thereof that would result in adverse balance sheet or creditworthiness impacts on Buyer associated with this Agreement or the amounts paid for Products purchased hereunder, the Parties agree to negotiate in good faith in an attempt to amend or clarify this Agreement to avoid or significantly mitigate such impacts. Provided, however, neither Party shall have any obligation to agree to any particular amendment or clarification of this Agreement, and such amendment or clarification shall not in any event alter (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

20. COUNTERPARTS; FACSIMILE SIGNATURES

Any number of counterparts of this Agreement may be executed, and each shall have the same force and effect as an original. Facsimile signatures hereon or on any notice or other instrument delivered under this Agreement shall have the same force and effect as original signatures.

21. NO DUTY TO THIRD PARTIES

Except as provided in any consent to assignment of this Agreement, nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a Party to this Agreement.

22. SEVERABILITY

If any term or provision of this Agreement or the interpretation or application of any term or provision to any prior circumstance is held to be unenforceable, illegal or invalid by a court or agency of competent jurisdiction, the remainder of this Agreement and the interpretation or application of all other terms or provisions to Persons or circumstances other than those which are unenforceable, illegal or invalid shall not be affected thereby, and each term and provision shall be valid and be enforced to the fullest extent permitted by law.

23. INDEPENDENT CONTRACTOR

Nothing in this Agreement shall be construed as creating any relationship between Buyer and Seller other than that of Seller as independent contractor for the sale of Products, and Buyer as principal and purchaser of the same. Neither Party shall be deemed to be the agent of the other Party for any purpose by reason of this Agreement, and no partnership or joint venture or fiduciary relationship between the Parties is intended to be created hereby.

24. ENTIRE AGREEMENT

This Agreement shall constitute the entire agreement and understanding between the Parties hereto and shall supersede all prior agreements and communications.

[Signature page follows]

IN WITNESS WHEREOF, each of Buyer and Seller has caused this Agreement to be duly executed on its behalf as of the date first above written.

[Buyer]

By: ________________________________

Name:
Title:

[Seller]

By: ________________________________

Name:
Title:

EXHIBIT A

DESCRIPTION OF FACILITY

Facility: [Describe fully, including the location (street address and county or if there is none, longitude and latitude), the technology, fuel type, Operational Limitations, Delivery Point and criteria for substantial completion of the Facility as specified by Seller in its response to the RFP.]

EXHIBIT B

SELLER'S CRITICAL MILESTONES
PERMITS AND REAL ESTATE RIGHTS

Part 1 – Permits

a. Construction Permits
[to be completed]

b. Operating Permits
[to be completed]

Part 2 – Real Estate Rights
[to be completed]

EXHIBIT C

FORM OF PROGRESS REPORT

For the Quarter Ending:__________________

Status of construction and significant construction milestones achieved during the quarter:

Status of permitting and significant Permits obtained during the quarter:

Status of Financing for Facility:

Events during quarter expected to results in delays in Commercial Operation Date:

Critical Milestones not yet achieved and projected date for achievement:

Current projection for Commercial Operation Date:

EXHIBIT D

PRODUCTS AND PRICING

1. Price.

(a) The Price per MWH for the Products shall be equal to [$__] per MWh, commencing on the Commercial Operation Date. The Price per MWh for each billing period shall be allocated between Energy and RECs as follows:

[Formulation for NU and Unitil]

(i) Energy = [amount bid by Seller]

(ii) RECs = [amount bid by Seller]

[Formulation for National Grid]

(i) Energy = The $/MWh price of Energy for the applicable month shall be equal to the weighted average of the Locational Marginal Price in that month (also on a $/MWh basis) for the Node on the Pool Transmission Facilities to which the Facility is interconnected.

(ii) RECs = The Price less the Energy allocation determined above for the applicable billing period, expressed in $/MWh.

(b) The Adjusted Price for Energy shall be equal to [$__] per MWh.

2. Payment. Buyer shall, in accordance with the terms of the Agreement and this Exhibit D, with respect to any month after the Commercial Operation Date, pay to Seller, in immediately available funds, for each MWh of Products Delivered by Seller during such month, the Price per MWh or Adjusted Price per MWh set forth in Section 1 above, as applicable. .

DRAFT[*]

POWER PURCHASE AGREEMENT

BETWEEN

[FITCHBURG GAS AND ELECTRIC LIGHT COMPANY, D/B/A UNITIL]
[MASSACHUSETTS ELECTRIC COMPANY AND
NANTUCKET ELECTRIC COMPANY, D/B/A NATIONAL GRID]
[NSTAR ELECTRIC COMPANY]
[WESTERN MASSACHUSETTS ELECTRIC COMPANY]

AND

[_________________]
[Seller]

As of [____________], 2013

[*] This draft Power Purchase Agreement is intended to provide a general description of the terms that the Massachusetts electric distribution companies are willing to agree to. The final Agreement will be subject to negotiations with the individual electric distribution companies. Accordingly, certain provisions in the final Agreement may differ from this draft Agreement. In addition, bidders proposing to recover significant transmission costs through federal transmission rates must include in their mark-up the additional material described in Section 2.2.4.2 of the RFP.

TABLE OF CONTENTS

Page

TABLE OF CONTENTS (CONT.)

Page

TABLE OF CONTENTS (CONT.)

Page

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT (as amended from time to time in accordance with the terms hereof, this **"Agreement"**) is entered into as of [_________], 2013 (the **"Effective Date"**), by and between [Fitchburg Gas and Electric Light Company, d/b/a Unitil, a Massachusetts corporation] [Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid, a Massachusetts corporation] [NSTAR Electric Company, a Massachusetts corporation] [Western Massachusetts Electric Company, a Massachusetts corporation] (**"Buyer"**), and [________________], a [__________________] (**"Seller"**). Buyer and Seller are individually referred to herein as a **"Party"** and are collectively referred to herein as the **"Parties"**.

WHEREAS, Seller is developing the [_______] electric generation facility to be located in [________],which is more fully described in Exhibit A hereto (the **"Facility"**), which shall qualify as a RPS Class I Renewable Generation Unit and which is expected to be in commercial operation by [_______]; and

WHEREAS, Buyer is required under Section 83 of the Massachusetts Green Communities Act to enter into certain long-term contracts for the purchase of energy and/or renewable energy certificates from renewable generators meeting the requirements of that statute; and

WHEREAS, Buyer and Seller desire to enter into this Agreement whereby Buyer shall purchase from Seller certain [Energy and/or RECs] (each as defined herein) generated by or associated with the Facility;

NOW, THEREFORE, in consideration of the premises and of the mutual agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

1. DEFINITIONS

In addition to terms defined in the recitals hereto, the following terms shall have the meanings set forth below. Any capitalized terms used in this Agreement and not defined herein shall have the same meaning as ascribed to such terms under the ISO-NE Practices and ISO-NE Rules.

"Adjusted Price" shall mean the purchase price(s) for Energy referenced in Section 5.1 if the RECs fail to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit and Buyer does not purchase the RECs pursuant to Section 4.1(b) hereof.

"Affiliate" shall mean, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries Controls, is Controlled by, or is under common Control with, such first Person.

"Agreement" shall have the meaning set forth in the first paragraph of this Agreement.

"Business Day" means a day on which Federal Reserve member banks in New York, New York are open for business; and a Business Day shall start at 8:00 a.m. and end at 5:00 p.m. Eastern Prevailing Time. Notwithstanding the foregoing, with respect to notices only, a Business Day shall not include the Friday immediately following the U.S. Thanksgiving holiday.

"Buyer's Percentage Entitlement" shall mean Buyer's rights to [________] percent ([__]%) of the Products, up to and including the Contract Maximum Amount.

"Buyer's Taxes" shall have the meaning set forth in Section 5.4(a) hereof.

"**Cash**" shall mean U.S. dollars held by or on behalf of a Party as Posted Collateral hereunder. ***[NATIONAL GRID VERSION]***

"Certificates" shall mean an electronic certificate created pursuant to the Operating Rules of the GIS or any successor thereto to represent the "generation attributes" (as defined in 225 CMR 14.02) of each MWh of Energy generated within the ISO-NE control area and the generation attributes of certain Energy imported into the ISO-NE control area.

"**Collateral Account**" shall have the meaning specified in Section 6.5(a)(iii)(B) hereof. ***[NATIONAL GRID VERSION]***

"**Collateral Interest Rate**" shall mean the rate published in *The Wall Street Journal* as the "Prime Rate" from time to time (or, if more than one such rate is published, the arithmetic mean of such rates), or, if such rate is no longer published, a successor rate agreed to by Buyer and Seller, in each case determined as of the date the obligation to pay interest arises, but in no event more than the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties. ***[NATIONAL GRID VERSION]***

"**Collateral Requirement**" shall mean at any time the amount of Development Period Security or Operating Period Security required under this Agreement at such time. ***[NATIONAL GRID VERSION]***

"Commercial Operation Date" shall mean the date on which the conditions set forth in Section 3.4(b) have been satisfied, as set out in a written notice from Seller to Buyer.

"Common Infrastructure" shall mean (i) any tie or transmission line, interconnection facility or Network Upgrade that is shared by the Facility and another generating facility (ii) any non-public road that is shared by the Facility and another generating facility and (iii) any control or communications facility or other infrastructure that is located within a five-mile radius of the Facility and is shared by the Facility and another generating facility.

"Companion Facility" shall have the meaning specified in Section 4.1(d) hereof.

"Contract Maximum Amount" shall mean [___] kWh per hour of Energy and a corresponding portion of all other Products.

"Contract Year" shall mean the twelve (12) consecutive calendar months starting on the first day of the calendar month following the Commercial Operation Date and each subsequent twelve (12) consecutive calendar month period; provided that the first Contract Year shall include the days in the prior month in which the Commercial Operation Date occurred.

"Control" shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise.

"Cover Damages" shall mean, with respect to any Delivery Failure, an amount equal to (a) the positive net amount, if, any, by which the Replacement Price exceeds the applicable Price that would have been paid pursuant to Section 5.1 hereof, multiplied by the quantity of that Delivery Failure, plus (b) any applicable penalties and other costs assessed by ISO-NE or any other Person against Buyer as a result of Seller's failure to deliver such Products in accordance with the terms of this Agreement. Buyer shall provide a statement for the applicable period explaining in reasonable detail the calculation of any Cover Damages.

"Credit Support" shall mean collateral in the form of (a) cash or (b) a letter of credit issued by a Qualified Bank in a form reasonably acceptable to the recipient Party. ***[NSTAR/UNITIL/WMECO VERSION]***

"Credit Support" shall have the meaning specified in Section 6.2(d) hereof. ***[NATIONAL GRID VERSION]***

"**Credit Support Delivery Amount"** shall have the meaning specified in Section 6.3 hereof. ***[NATIONAL GRID VERSION]***

"**Credit Support Return Amount**" shall have the meaning specified in Section 6.4 hereof. ***[NATIONAL GRID VERSION]***

"Critical Milestones" shall have the meaning set forth in Section 3.1 hereof.

"**Custodian**" shall have the meaning specified in Section 6.5(a)(i) hereof. ***[NATIONAL GRID VERSION]***

"**Day Ahead Energy Market**" shall have the meaning set forth in the ISO-NE Rules.

"Default" shall mean any event or condition which, with the giving of notice or passage of time or both, could become an Event of Default.

"Defaulting Party" shall mean the Party with respect to which a Default or Event of Default has occurred.

"Delay Damages" shall mean the damages assessed pursuant to Section 3.2(a) hereof.

"Deliver" or **"Delivery"** shall mean with respect to (i) Energy, to supply Energy into Buyer's ISO-NE account at the Delivery Point in accordance with the terms of this Agreement and the ISO-NE Rules, and (ii) RECs, to supply RECs in accordance with Section 4.7(e).

"Delivery Failure" shall have the meaning set forth in Section 4.3 hereof.

"Delivery Point" shall mean the specific Node on the ISO-NE Pool Transmission Facilities, as determined by ISO-NE, where Seller shall transmit its Energy to Buyer, as set forth in Exhibit A hereto.

"Development Period Security" shall have the meaning set forth in Section [6.1(a)] [6.2(a)] hereof.

"DOER" shall mean the Massachusetts Department of Energy Resources and shall include its successors.

"Dispute" shall have the meaning set forth in Section 11.1 hereof.

"**Disputing Party**" shall have the meaning set forth in Section 6.6(a) hereof.
[NATIONAL GRID VERSION]

"Eastern Prevailing Time" shall mean either Eastern Standard Time or Eastern Daylight Savings Time, as in effect from time to time.

"Effective Date" shall have the meaning set forth in the first paragraph hereof.

"Energy" shall mean electric "energy," as such term is defined in the ISO-NE Tariff, generated by the Facility as measured in kWh in Eastern Prevailing Time, less such Facility's station service use, generator lead losses and transformer losses, which quantity for purposes of this Agreement will never be less than zero.

"Environmental Attributes" shall mean any and all generation attributes under the DOER's RPS regulations and under any and all other international, federal, regional, state or other law, rule, regulation, bylaw, treaty or other intergovernmental compact, decision, administrative decision, program (including any voluntary compliance or membership program), competitive market or business method (including all credits, certificates, benefits, and emission measurements, reductions, offsets and allowances related thereto) that are attributable, now or in the future, to Buyer's Percentage Entitlement to the favorable generation or environmental attributes of the Facility or the Products produced by the Facility, up to and including the Contract Maximum Amount, during the Services Term including Buyer's Percentage Entitlement to: (a) any such credits, certificates, benefits, offsets and allowances computed on the basis of the Facility's generation using renewable technology or displacement of fossil-fuel derived or other conventional energy generation; (b) any Certificates issued pursuant to the GIS in connection with Energy generated by the Facility; and (c) any voluntary emission reduction credits obtained or obtainable by Seller in connection with the generation of Energy by the Facility; provided, however, that Environmental Attributes shall not include: (i) any production tax credits; (ii) any investment tax credits or other tax credits associated with the construction or ownership of the Facility; or (iii) any state, federal or private grants, financing, guarantees or other credit support relating to the construction or ownership, operation or maintenance of the Facility or the output thereof.

"Event of Default" shall have the meaning set forth in Section 9.1 hereof and shall include the events and conditions described in Section 9.1 and Section 9.2 hereof.

"EWG" shall mean an exempt wholesale generator under 15 U.S.C. § 79z-5a, as amended from time to time.

"Facility" shall have the meaning set forth in the Recitals.

"FERC" shall mean the United States Federal Energy Regulatory Commission, and shall include its successors.

"Financial Closing Date" shall mean the date of signing of the initial agreements for any Financing of the Facility and of an initial disbursement of funds under such agreements.

"Financing" shall mean indebtedness, whether secured or unsecured, loans, guarantees, notes, equity, convertible debt, sale-leaseback or other tax-equity transactions, bond issuances, recapitalizations and all similar financing or refinancing.

"Force Majeure" shall have the meaning set forth in Section 10.1(a) hereof.

"Generation Unit" shall mean a facility that converts a fuel or an energy resource into electrical energy.

"GIS" shall mean the New England Power Pool Generation Information System or any successor thereto, which includes a generation information database and certificate system, operated by NEPOOL, its designee or successor entity, that accounts for generation attributes of electricity generated or consumed within New England.

"Good Utility Practice" shall mean compliance with all applicable laws, codes and regulations, all ISO-NE Rules and ISO-NE Practices, and any practices, methods and acts engaged in or approved by a significant portion of the electric industry in New England during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision is made, could have been expected to accomplish the desired result consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather is intended to include acceptable practices, methods and acts generally accepted in the industry in New England.

"Governmental Entity" shall mean any federal, state or local governmental agency, authority, department, instrumentality or regulatory body, and any court or tribunal, with jurisdiction over Seller, Buyer or the Facility.

"Interconnecting Utility" shall mean that the utility (which may be Buyer or an Affiliate of Buyer) providing interconnection service for the Facility to the transmission system of that utility.

"Interconnection Agreement" shall mean an agreement between Seller and the Interconnecting Utility regarding the interconnection of the Facility to the transmission system of the Interconnecting Utility, as the same may be amended from time to time.

"Interconnection Point" shall have the meaning set forth in the Interconnection Agreement.

"**Interest Amount**" shall mean with respect to a Party and an Interest Period, the sum of the daily interest amounts for all days in such Interest Period; each daily interest amount to be determined by such Party as follows: (a) the amount of Cash held by such Party on that day (but excluding any interest previously earned on such Cash); multiplied by (b) the Collateral Interest Rate for that day; divided by (c) 360. ***[NATIONAL GRID VERSION]***

"**Interest Period**" shall mean the period from (and including) the last Business Day on which an Interest Amount was Transferred by Buyer (or if no Interest Amount has yet been Transferred by Buyer, the Business Day on which Cash was Transferred to Seller) to (but excluding) the Business Day on which the current Interest Amount is to be Transferred. ***[NATIONAL GRID VERSION]***

"ISO" or **"ISO-NE"** shall mean ISO New England Inc., the independent system operator established in accordance with the RTO arrangements for New England, or its successor.

"ISO-NE Practices" shall mean the ISO-NE practices and procedures for delivery and transmission of energy in effect from time to time and shall include, without limitation, applicable requirements of the NEPOOL Agreement, and any applicable successor practices and procedures.

"ISO-NE Rules" shall mean all rules and procedures adopted by NEPOOL, ISO-NE, or the RTO, and governing wholesale power markets and transmission in New England, as such rules may be amended from time to time, including but not limited to, the ISO-NE Tariff, the ISO-NE Operating Procedures (as defined in the ISO-NE Tariff), the ISO-NE Planning Procedures (as defined in the ISO-NE Tariff), the Transmission Operating Agreement (as defined in the ISO-NE Tariff), the Participants Agreement, the manuals, procedures and business process documents published by ISO-NE via its web site and/or by its e-mail distribution to appropriate NEPOOL participants and/or NEPOOL committees, as amended, superseded or restated from time to time.

"ISO-NE Tariff" shall mean ISO-NE's Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, as amended from time to time.

"ISO Settlement Market System" shall have the meaning as set forth in the ISO-NE Tariff.

"kW" shall mean a kilowatt.

"kWh" shall mean a kilowatt-hour.

"Late Payment Rate" shall have the meaning set forth in Section 5.3 hereof.

"Law" shall mean all federal, state and local statutes, regulations, rules, orders, executive orders, decrees, policies, judicial decisions and notifications.

"Lender" shall mean any party providing financing for the development and construction of the Facility, or any refinancing of that financing, and receiving a security interest in the Facility, and shall include any assignee or transferee of such a party and any trustee, collateral agent or similar entity acting on behalf of such a party.

"**Letter of Credit**" shall mean an irrevocable, non-transferable, standby letter of credit, issued by a Qualified Institution utilizing a form acceptable to the Party in whose favor such letter of credit is issued. All costs relating to any Letter of Credit shall be for the account of the Party providing that Letter of Credit. ***[NATIONAL GRID VERSION]***

"**Letter of Credit Default**" shall mean with respect to an outstanding Letter of Credit, the occurrence of any of the following events (a) the issuer of such Letter of Credit shall fail to be a Qualified Institution; (b) the issuer of the Letter of Credit shall fail to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after the lapse of any applicable grace period; (c) the issuer of the Letter of Credit shall disaffirm, disclaim, repudiate or reject, in whole or in part, or challenge the validity of, such Letter of Credit; or (d) the Letter of Credit shall expire or terminate or have a Value of $0 at any time the Party on whose account that Letter of Credit is issued is required to provide Credit Support hereunder and that Party has not Transferred replacement Credit Support meeting the requirements of this Agreement; provided, however, that no Letter of Credit Default shall occur in any event with respect to a Letter of Credit after the time such Letter of Credit is required to be cancelled or returned in accordance with the terms of this Agreement. ***[NATIONAL GRID VERSION]***

"MDPU" shall mean the Massachusetts Department of Public Utilities and shall include its successors.

"Meters" shall have the meaning set forth in Section 4.6(a) hereof.

"Moody's" shall mean Moody's Investors Service, Inc., and any successor thereto.

"MW" shall mean a megawatt.

"MWh" shall mean a megawatt-hour (one MWh shall equal 1,000 kWh).

"NEPOOL" shall mean the New England Power Pool and any successor organization.

"NEPOOL Agreement" shall mean the Second Amended and Restated New England Power Pool Agreement dated as of February 1, 2005, as amended and/or restated from time to time.

"NERC" shall mean the North American Electric Reliability Council and shall include any successor thereto.

"Network Upgrades" shall mean upgrades to the Pool Transmission Facilities and the Transmission Provider's transmission system necessary for Delivery of the Energy to the Delivery Point, as determined and identified in the interconnection study approved in connection with construction of the Facility, such that the maximum output of the Facility could be qualified to participate in the ISO-NE Forward Capacity Market (as defined in the ISO-NE Rules) or any successor thereof.

"Node" shall have the meaning set forth in Market Rule 1.

"Non-Defaulting Party" shall mean the Party with respect to which a Default or Event of Default has not occurred.

"**Obligations**" shall have the meaning specified in Section 6.1 hereof. ***[NATIONAL GRID VERSION]***

"Operational Limitations" of the Facility are the parameters set forth in Exhibit A describing the physical limitations of the Facility, including the time required for start-up and the limitation on the number of scheduled start-ups per Contract Year.

"Operating Period Security" shall have the meaning set forth in Section [6.1(b)] [6.2(b)] hereof.

"Party" and **"Parties"** shall have the meaning set forth in the first paragraph of this Agreement.

"Permits" shall mean any permit, authorization, license, order, consent, waiver, exception, exemption, variance or other approval by or from, and any filing, report, certification, declaration, notice or submission to or with, any Governmental Entity required to authorize action, including any of the foregoing relating to the ownership, siting, construction, operation, use or maintenance of the Facility under any applicable Law.

"Person" shall mean an individual, partnership, corporation, limited liability company, limited liability partnership, limited partnership, association, trust, unincorporated organization, or a government authority or agency or political subdivision thereof.

"Pool Transmission Facilities" has the meaning given that term in the ISO-NE Rules.

"**Posted Collateral**" shall mean all Credit Support and all proceeds thereof that have been Transferred to or received by a Party under this Agreement and not Transferred to the Party providing the Credit Support or released by the Party holding the Credit

Support. Any Interest Amount or portion thereof not Transferred will constitute Posted Collateral in the form of Cash. ***[NATIONAL GRID VERSION]***

"**Power Cost Reconciliation Tariff**" shall mean a fully reconciling cost recovery tariff mechanism that authorizes the establishment of a distribution charge that fully recovers Buyer's net costs under this Agreement (including the annual remuneration of two and three-quarters percent (2.75%)). The rate reconciliation shall be designed in such a way as to limit the build up of any under or over-recoveries over the course of the year. A reconciliation shall occur at least annually, but may also be reconciled quarterly or monthly, to the extent necessary to eliminate regulatory lag for the recovery of costs or crediting of over-recoveries to customers.

"Price" shall mean the purchase price(s) for Products referenced in Section 5.1 hereof.

"Products" shall mean [Energy and/or RECs]; provided, however, that [Energy and/or RECs] generated by the Facility during the Test Period or in excess of the Contract Maximum Amount and RECs not purchased by Buyer under Section 4.1(b) shall not be deemed Products. *[dependent on accepted bid]*

"**Purchased Power Accounting Authorization**" shall mean authorization for Buyer, at Buyer's sole discretion, to take appropriate steps to assure avoidance of a material, negative balance sheet impact on Buyer or Buyer's direct or indirect parent company, upon appropriate filing with and approval by the MDPU; provided that, subject to Section 8.3, such Purchased Power Accounting Authorization shall not impact Buyer's obligation to purchase the Products under this Agreement or the Price Buyer pays for such Products.

"QF" shall mean a cogeneration or small power production facility which meets the criteria as defined in Title 18, Code of Federal Regulations, §§ 292.201 through 292.207, as amended from time to time.

"Qualified Bank" shall mean a major U.S. commercial bank or the U.S. branch office of a major foreign bank, in either case, having (x) assets on its most recent audited balance sheet of at least $10,000,000,000 and (y) a rating for its senior long-term unsecured debt obligations of at least (A) "A" by S&P and "A2" by Moody's, if such entity is rated by both S&P and Moody's or (B) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both. ***[NSTAR/UNITIL/WMECO VERSION]***

"Qualified Institution" shall mean a major U.S. commercial bank or trust company, the U.S. branch office of a foreign bank, or another financial institution, in any case, organized under the laws of the United States or a political subdivision thereof having assets of at least $10 billion and a credit rating of at least (A) "A2" from Moody's or "A" from S&P, if such entity is rated by both S&P and Moody's or (B) "A" by S&P or "A2" by Moody's, if such entity is rated by either S&P or Moody's but not both. ***[NATIONAL GRID VERSION]***

"Real-Time Energy Market" shall have the meaning as set forth in the ISO-NE Rules.

"**Reference Market-Maker**" shall mean a leading dealer in the relevant market that is selected in a commercially reasonable manner and is not an affiliate of either party. ***[NATIONAL GRID VERSION]***

"**Regulatory Approval**" shall mean the MDPU's approval of this entire Agreement, which approval shall include without limitation: (1) confirmation that this Agreement has been approved under Section 83A of Massachusetts Senate Bill 2395, *An Act relative to competitively priced electricity in the Commonwealth*, and the regulations promulgated thereunder and that all of the terms of such Section 83A and such regulations apply to this Agreement; (2) definitive regulatory authorization for Buyer to recover all of its costs incurred under this Agreement for the entire term of this Agreement through the implementation of a Power Cost Reconciliation Tariff and/or other cost recovery or reconciliation mechanisms; (3) definitive regulatory authorization for Buyer to recover remuneration equal to two and three-quarters percent (2.75%) of Buyer's annual payments under this Agreement for the term of this Agreement through the Power Cost Reconciliation Tariff; and (4) approval of any Purchased Power Accounting Authorization requested by Buyer in connection with the Regulatory Approval. Such approvals shall be acceptable in form and substance to Buyer in its sole discretion, shall not include any conditions or modifications that Buyer deems, in its sole discretion, to be unacceptable and shall be final and not subject to appeal or rehearing.

"**Rejected Purchase**" shall have the meaning set forth in Section 4.4 hereof.

"**Renewable Energy Certificates**" or "**RECs**" shall mean all of the Certificates and any and all other Environmental Attributes associated with the Products or otherwise produced by the Facility which satisfy the RPS for a RPS Class I Renewable Generation Unit, and shall represent title to and claim over all Environmental Attributes associated with the specified MWh of generation from such RPS Class I Renewable Generation Unit.

"**Replacement Energy**" shall mean Energy purchased by Buyer as replacement for any Delivery Failure.

"**Replacement Price**" shall mean the price at which Buyer, acting in a commercially reasonable manner, purchases Replacement Energy and Replacement RECs plus (i) transaction and other administrative costs reasonably incurred by Buyer in purchasing such Replacement Energy and Replacement RECs and (ii) additional transmission charges, if any, reasonably incurred by Buyer to transmit Replacement Energy to the Delivery Point; provided, however, that (a) in no event shall Buyer be required to utilize or change its utilization of its owned or controlled assets, contracts or market positions to minimize Seller's liability, (b) Buyer shall have no obligation to purchase Replacement Energy and/or Replacement RECs, and (c) if Buyer does not purchase Replacement Energy and/or Replacement RECs, the market value of Energy and/or RECs at the time of the Delivery Failure (as reasonably determined by Buyer) will replace the price at which Buyer purchases Replacement Energy and/or Replacement RECs in the calculation of the Replacement Price.

"Replacement RECs" shall mean any generation or environmental attributes, including any Certificates or other certificates or credits related thereto reflecting generation by a RPS Class I Renewable Generation Unit that are purchased by Buyer as replacement for any Delivery Failure.

"Request Date" shall have the meaning set forth in Section 6.6(a) hereof. ***[NATIONAL GRID VERSION]***

"**Requesting Party**" shall have the meaning set forth in Section 6.6(a) hereof. ***[NATIONAL GRID VERSION]***

"Resale Damages" shall mean, with respect to any Rejected Purchase, an amount equal to (a) the positive net amount, if any, by which the applicable Price that would have been paid pursuant to Section 5.1 hereof for such Rejected Purchase, had it been accepted, exceeds the Resale Price multiplied by the quantity of that Rejected Purchase, plus (b) any applicable penalties assessed by ISO-NE or any other Person against Seller as a result of Buyer's failure to accept such Products. Seller shall provide a written statement explaining in reasonable detail the calculation of any Resale Damages.

"Resale Price" shall mean the price at which Seller, acting in a commercially reasonable manner, sells or is paid for a Rejected Purchase, plus transaction and other administrative costs reasonably incurred by Seller in re-selling such Rejected Purchase; provided, however, that in no event shall Seller be required to utilize or change its utilization of the Facility or its other assets, contracts or market positions in order to minimize Buyer's liability for such Rejected Purchase.

"**Rounding Amount**" shall have the meaning specified in Section 6.2(c) hereof. ***[NATIONAL GRID VERSION]***

"RPS" shall mean the requirements established pursuant to Mass. Gen. Laws ch. 25A, § 11F that require all retail electricity suppliers in Massachusetts to provide a minimum percentage of electricity from RPS Class I Renewable Generation Units, and such successor laws and regulations as may be in effect from time to time.

"RPS Class I Renewable Generation Unit" shall mean a Generation Unit that has received a Statement of Qualification from the DOER, including a Generation Unit termed a New Renewable Generation Unit in a Statement of Qualification issued by the DOER pursuant to 225 CMR 14.00.

"RTO" shall mean ISO-NE and any successor organization or entity to ISO-NE, as authorized by FERC to exercise the functions pursuant to the FERC's Order No. 2000 and FERC's corresponding regulations, or any successor organization, or any other entity authorized to exercise comparable functions in subsequent orders or regulations of FERC.

"S&P" shall mean Standard & Poor's Financial Services LLC , and any successor thereto.

"Schedule or Scheduling" shall mean the actions of Seller and/or its designated representatives pursuant to Section 4.2, of notifying, requesting and confirming to ISO-NE the quantity of Energy to be delivered on any given day or days (or in any given hour or hours) during the Services Term at the Delivery Point.

"Services Term" shall have the meaning set forth in Section 2.2(b) hereof.

"Seller's Taxes" shall have the meaning set forth in Section 5.4(a) hereof.

"**Statement of Qualification**" shall mean a written document from the DOER that qualifies a Generation Unit as an RPS Class I Qualified Generation Unit, or that qualifies a portion of the annual electrical energy output of a Generation Unit as RPS Class I Renewable Generation (as defined in 225 CMR 14.01).

"**Substitute Credit Support**" shall have the meaning assigned in Section 6.5(f) hereof. ***[NATIONAL GRID VERSION]***

"Term" shall have the meaning set forth in Section 2.2(a) hereof.

"Termination Payment" shall have the meaning set forth in Section 9.3(b) hereof.

"Test Period" shall have the meaning set forth in Section 3.4(a) hereof.

"Transfer" shall mean, with respect to any Posted Collateral or Interest Amount, and in accordance with the instructions of the Party entitled thereto:

(a) in the case of Cash, payment or transfer by wire transfer into one or more bank accounts specified by the Party to whom such Cash is being delivered; and

(b) in the case of Letters of Credit, delivery of the Letter of Credit or an amendment thereto to the Party to whom such Letter of Credit is being delivered. ***[NATIONAL GRID VERSION]***

"Transmission Provider" shall mean (a) ISO-NE, its respective successor or Affiliates; (b) Buyer; and/or (c) such other third parties from whom transmission services are necessary for Seller to fulfill its performance obligations to Buyer hereunder, as the context requires.

"Valuation Agent" means the Requesting Party; provided, however, that that in all cases, if an Event of Default has occurred and is continuing with respect to the Party designated as the Valuation Agent, then in such case, and for so long as the Event of Default continues, the other Party shall be the Valuation Agent. ***[NATIONAL GRID VERSION]***

"Valuation Date" shall mean each Business Day. ***[NATIONAL GRID VERSION]***

"Valuation Percentage" shall have the meaning specified in Section 6.2(d) hereof. ***[NATIONAL GRID VERSION]***

"Valuation Time" shall mean the close of business on the Business Day before the Valuation Date or date of calculation, as applicable. ***[NATIONAL GRID VERSION]***

"Value" shall mean, with respect to Posted Collateral or Credit Support, the Valuation Percentage multiplied by the amount then available under the Letter of Credit to be unconditionally drawn by Buyer. ***[NATIONAL GRID VERSION]***

2. EFFECTIVE DATE; TERM

2.1 Effective Date. Subject to Section 8.1, this Agreement is effective as of the Effective Date.

2.2 Term.

(a) The **"Term"** of this Agreement is the period beginning on the Effective Date and ending upon the final settlement of all obligations hereunder after the expiration of the Services Term or the earlier termination of this Agreement in accordance with its terms.

(b) The **"Services Term"** is the period during which Buyer is obligated to purchase Products Delivered to Buyer by Seller (not including Energy and RECs Delivered during the Test Period under Section 4.8) commencing on the Commercial Operation Date and continuing for a period of [10 to 20] years from the Commercial Operation Date, unless this Agreement is earlier terminated in accordance with the provisions hereof.

(c) At the expiration of the Services Term, the Parties shall no longer be bound by the terms and provisions hereof (including, without limitation, any payment obligation hereunder), except (i) to the extent necessary to provide invoices and make payments or refunds with respect to Products delivered prior to such expiration or termination, (ii) to the extent necessary to enforce the rights and the obligations of the Parties arising under this Agreement before such expiration or termination, and (iii) the obligations of the Parties hereunder with respect to confidentiality and indemnification shall survive the expiration or termination of this Agreement.

(d) At the expiration of the Services Term, Buyer shall have the right, exercisable in Buyer's sole discretion, to negotiate in good faith with Seller for no more than sixty (60) days, the terms of the sale of such Energy and/or RECs generated by the Facility (or a portion thereof, as selected by Buyer) to Buyer or its designee on an exclusive basis. If Buyer wishes to enter into such negotiation, Buyer shall notify Seller of such decision at least one year prior to the expiration of the Services Term, and such negotiations shall commence at least eleven months prior to the expiration of the Services Term. Seller shall supply in a timely manner, information regarding the Facility which is customary to allow Buyer to perform due diligence and to negotiate in good faith for the purchase of such Energy and/or RECs.

3. FACILITY DEVELOPMENT AND OPERATION

3.1 Critical Milestones.

(a) Subject to the provisions of Section 3.1(c), commencing on the Effective Date, Seller shall develop the Facility in order to achieve the following milestones (**"Critical Milestones"**) on or before the date set forth in this Section 3.1(a):

(i) receipt of all Permits necessary to construct the Facility, as set forth in Exhibit B, in final form, by [_________];

(ii) acquisition of all required real property rights necessary for construction and operation of the Facility, interconnection of the Facility to the Interconnecting Utility, and performance of Seller's obligations under this Agreement as set forth on Exhibit B, by [_________];

(iii) demonstration of the financial capability (whether through third party financing to Seller or Seller's own financial assets) to proceed with the development and construction of the Facility, including, as applicable, Seller's financial obligations with respect to interconnection of the Facility to the Interconnecting Utility and construction of the Network Upgrades by [__________] [on or before 12/31/15] [*TBD for alternative bid*]; and

(iv) achievement of the Commercial Operation Date by [___________] [on or before 12/31/16] [on or before 12/31/18 *for alternative bid*].

(b) Seller shall provide Buyer with written notice of the achievement of each Critical Milestone within seven (7) days after that achievement, which notice shall include information demonstrating with reasonable specificity that such Critical Milestone has been achieved. Seller acknowledges that Buyer requires such written notice solely for monitoring purposes, and that nothing set forth in this Agreement shall create or impose upon Buyer any responsibility or liability for the development, construction, operation or maintenance of the Facility.

(c) In addition to any extension of a date for a Critical Milestone as a result of a Force Majeure under Section 10.1, Seller may elect to extend all of the dates for the Critical Milestones not yet achieved (i) by one year without posting additional Development Period Security and (ii) by up to two additional six month periods by posting additional Development Period Security of $[________] [$5 per kWh of Contract Maximum Amount] for each such six-month period. In no event may Seller exercise the right to extend the Critical Milestone dates under this Section 3.1(c) by more than two years, and in no event shall any extension of the Critical Milestone dates as a result of one or more Force Majeure events exceed a cumulative total of an additional twelve (12) months. Any such election shall be made in a written notice delivered to Buyer on or prior to the first date for a Critical Milestone that has not yet been achieved (as such date may have previously been extended).

(d) The Parties agree that time is of the essence with respect to the Critical Milestones and is part of the consideration to Buyer in entering into this Agreement.

3.2 Delay Damages.

(a) If the Commercial Operation Date is not achieved by the date set forth therefor in Section 3.1(a) (as extended pursuant to Section 3.1(c)), Seller shall pay to Buyer damages for each month from and after such date until the Commercial Operation Date at the rate of $[___] per month [$1.50 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $1.00 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $0.50 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] up to a maximum of twelve (12) months of delay, pro rated for partial months (**"Delay Damages"**). Delay Damages shall be due under this Section 3.2(a) without regard to whether Buyer exercises its right to terminate this Agreement pursuant to Section 9.3; provided, however, that if Buyer exercises its right to terminate this Agreement under Section 9.3, Delay Damages shall be due and owing to the extent that such Delay Damages were due and owing at the date of such termination.

(b) Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to Seller's delay in achieving the Commercial Operation Date would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Delay Damages as agreed to by the Parties and set forth herein are a fair and reasonable calculation of such damages. Notwithstanding the foregoing, this Article shall not limit the amount of damages payable to Buyer if this Agreement is terminated as a result of Seller's failure to achieve the Commercial Operation Date. Any such termination damages shall be determined in accordance with Article 9.

(c) By the tenth (10th) day following the end of the calendar month in which Delay Damages first become due and continuing by the tenth (10th) day of each calendar month during the period in which Delay Damages accrue (and the following months if applicable), Buyer shall deliver to Seller an invoice showing Buyer's computation of such damages and any amount due Buyer in respect thereof for the preceding calendar month. No later than ten (10) days after receiving such an invoice, Seller shall pay to Buyer, by wire transfer of immediately available funds to an account specified in writing by Buyer or by any other means agreed to by the Parties in writing from time to time, the amount set forth as due in such invoice. If Seller fails to pay such amounts when due, Buyer may draw upon the Development Period Security for payment of such Delay Damages, and Buyer may exercise any other remedies available for Seller's default hereunder.

3.3 Construction.

(a) Progress Reports. At the end of each calendar quarter after the Effective Date and until the Commercial Operation Date, Seller shall provide Buyer with a progress report regarding Critical Milestones not yet achieved, including projected time to completion of the Facility, in accordance with the form attached hereto as Exhibit C, and shall provide supporting documents and detail regarding the same upon Buyer's request. Seller shall permit Buyer and its advisors and consultants to review and discuss with Seller and its advisors and consultants such progress reports during business hours and upon reasonable notice to Seller.

(b) Site Access. Buyer and its representatives shall have the right but not the obligation, during business hours and upon reasonable notice to Seller, to inspect the Facility site and monitor the construction of the Facility.

3.4 Commercial Operation.

(a) Seller's obligation to Deliver the Products and Buyer's obligation to pay Seller for such Products commences on the Commercial Operation Date; provided, that Energy and RECs generated by the Facility prior to the Commercial Operation Date (the **"Test Period"**) shall not be deemed Products.

(b) The Commercial Operation Date shall occur on the date on which the Facility is substantially completed as described in Exhibit A and capable of regular commercial operation in accordance with Good Utility Practice, the manufacturer's guidelines for all material components of the Facility, all requirements of the ISO-NE Rules and ISO-NE Practices for the delivery of the Products to the Seller have been satisfied, and all performance testing for the Facility has been successfully completed, provided Seller has also satisfied the following conditions precedent as of such date:

(i) completion of all transmission and interconnection facilities and any Network Upgrades, including final acceptance and authorization to interconnect the Facility from ISO-NE or the Interconnecting Utility in accordance with the fully executed Interconnection Agreement;

(ii) Seller has obtained and demonstrated possession of all Permits required for the lawful construction and operation of the Facility, for the interconnection of the Facility to the Interconnecting Utility (including any Network Upgrades) and for Seller to perform its obligations under this Agreement, including but not limited to Permits related to environmental matters, all as set forth on Exhibit B;

(iii) Seller has obtained a Statement of Qualification from the DOER pursuant to 225 CMR 14.05 qualifying the Facility as a RPS Class I Renewable Generation Unit;

(iv) Seller has acquired all real property rights needed to construct and operate the Facility, to interconnect the Facility to the Interconnecting Utility, to construct the Network Upgrades (to the extent that it is Seller's responsibility to do so) and to perform Seller's obligations under this Agreement;

(v) Seller has established all ISO-NE-related accounts and entered into all ISO-NE-related agreements required for the performance of Seller's obligations in connection with the Facility and this Agreement, which agreements shall be in full force and effect, including the registration of the Facility in the GIS;

(vi) Seller has provided to Buyer I.3.9 confirmation from ISO-NE regarding approval of generation entry, has submitted the Asset Registration Form (as defined in ISO-NE Practices) for the Facility to ISO-NE and has taken such other actions as are necessary to effect the transfer of the Energy to Buyer in the ISO Settlement Market System;

(vii) Seller has successfully completed all pre-operational testing and commissioning in accordance with manufacturer guidelines;

(viii) Seller has satisfied all Critical Milestones that precede the Commercial Operation Date in Section 3.1;

(ix) no Default or Event of Default by Seller shall have occurred and remain uncured; and

(x) the Facility is owned or leased by, and under the care, custody and control of, Seller.

3.5 Operation of the Facility.

(a) Compliance With Utility Requirements. Seller shall comply with, and cause the Facility to comply with: (i) Good Utility Practice; (ii) the Operational Limitations; and (iii) all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by ISO-NE, any Transmission Provider, any Interconnecting Utility, NERC and/or any regional reliability entity, including, in each case, all practices, requirements, rules, procedures and standards related to Seller's construction, ownership, operation and maintenance of the Facility and its performance of its obligations under this Agreement (including obligations related to the generation, Scheduling, interconnection, and transmission of Energy, and the transfer of RECs), whether such requirements were imposed prior to or after the Effective Date. Seller shall be solely responsible for registering as the "Generator Owner and Generator Operator" of the Facility with NERC and any applicable regional reliability entities.

(b) Permits. Seller shall maintain in full force and effect all Permits necessary for it to perform its obligations under this Agreement, including all Permits necessary to operate and maintain the Facility.

(c) Maintenance and Operation of Facility. Seller shall, at all times during the Term, construct, maintain and operate the Facility in accordance with Good Utility Practice and in accordance with Exhibit A to this Agreement. Seller shall bear all costs related thereto. Seller may contract with other Persons to provide discrete construction, operation and maintenance functions, so long as Seller maintains overall control over the construction, operation and maintenance of the Facility throughout the Term.

(d) Interconnection Agreement. Seller shall comply with the terms and conditions of the Interconnection Agreement.

(e) ISO-NE Status. Seller shall, at all times during the Services Term, either: (i) be an ISO-NE "Market Participant" pursuant to the ISO-NE Rules; or (ii) have entered into an agreement with a Market Participant that shall perform all of Seller's ISO-NE-related obligations in connection with the Facility and this Agreement.

(f) Forecasts. Commencing at least thirty (30) days prior to the anticipated Commercial Operation Date and continuing throughout the Term, Seller shall update and deliver to Buyer on a monthly basis and in a form reasonably acceptable to Buyer, twelve (12) month rolling forecasts of Energy production by the Facility, which forecasts shall be prepared in good faith and in accordance with Good Utility Practice based on historical performance, maintenance schedules, Seller's generation projections and other relevant data and considerations. Any notable changes from prior forecasts or historical energy delivery shall be noted and an explanation provided. The provisions of this section are in addition to Seller's requirements under ISO-NE Rules and ISO-NE Practices, including ISO-NE Operating Procedure No. 5.

(g) RPS Class I Renewable Generation Unit. Seller shall be solely responsible for qualifying the Facility with the DOER as a RPS Class I Renewable Generation Unit in accordance with 225 CMR 14.05 and maintaining such Statement of Qualification throughout the Services Term; provided, however, that if the Facility ceases to qualify as a RPS Class I Renewable Generation Unit solely as a result of a change in Law, Seller shall only be required to use commercially reasonable efforts to maintain such Statement of Qualification after that change in Law.

(h) Compliance Reporting. Within fifteen days (15) days following the end of each calendar quarter, Seller shall provide Buyer information pertaining to power plant emissions, fuel types, labor information and any other information to the extent required by Buyer to comply with the uniform disclosure requirements contained in 220 CMR 11.00 and any other such disclosure regulations which may be imposed upon Buyer during the Term, which information requirements will be provided to Seller by Buyer at least fifteen (15) days before the beginning of the calendar quarter for which the information is required. To the extent Buyer is subject to any other certification or compliance reporting requirement with respect to the Products produced by Seller and delivered to Buyer hereunder, Seller shall provide any information in its possession (or, if not in Seller's possession, available to it and not reasonably available to Buyer) requested by Buyer to permit Buyer to comply with any such reporting requirement.

(i) Insurance. Throughout the Term, and without limiting any liabilities or any other obligations of Seller hereunder, Seller shall secure and continuously carry with an insurance company or companies rated not lower than “A-” by the A.M. Best Company the insurance coverage and with the deductibles that are customary for a generating facility of the type and size of the Facility and as otherwise legally required.. Within thirty (30) days prior to the start of each Contract Year, Seller shall provide Buyer with a certificate of insurance which (i) shall include Buyer as an additional insured on each policy, (ii) shall not include the legend “certificate is not evidence of coverage” or any statement with similar effect, (iii) shall evidence a firm obligation of the insurer to provide Buyer with thirty (30) days prior written notice of coverage modifications, and (iv) shall be endorsed by a Person who has authority to bind the insurer. If any coverage is written on a “claims-made” basis, the certification accompanying the policy shall conspicuously state that the policy is “claims made.”

(j) Contacts. Each Party shall identify a principal contact or contacts, which contact(s) shall have adequate authority and expertise to make day-to-day decisions with respect to the administration of this Agreement.

(k) Compliance with Law. Without limiting the generality of any other provision of this Agreement, Seller shall be responsible for complying with all applicable requirements of Law, including all applicable rules, procedures, operating policies, criteria, guidelines and requirements imposed by FERC and any other Governmental Entity, whether imposed pursuant to existing Law or procedures or pursuant to changes enacted or implemented during the Term, including all risks of environmental matters relating to the Facility or the Facility site. Seller shall indemnify Buyer against any and all claims arising out of or related to such environmental matters and against any costs imposed on Buyer as a result of Seller’s violation of any applicable Law, or ISO-NE or NERC requirements. For the avoidance of doubt, Seller shall be responsible for procuring, at its expense, all Permits and governmental approvals required for the construction and operation of the Facility in compliance with Law.

(l) FERC Status. Seller shall maintain the Facility’s status as a QF or EWG at all times after the Commercial Operation Date and shall obtain and maintain any requisite authority to sell the output of the Facility at market-based rates.

(m) Emissions. Seller shall be responsible for all costs associated with the Facility’s emissions, including the cost of procuring emission reductions, offsets, allowances or similar items associated with the Facility’s emissions, to the extent required to operate the Facility. Without limiting the generality of the foregoing, failure or inability of Seller to procure emission reductions, offsets, allowances or similar items associated with the Facility’s emissions shall not constitute a Force Majeure.

3.6 Interconnection and Delivery Services.

(a) Seller shall be responsible for all costs associated with interconnection of the Facility at the Interconnection Point, including the costs of the Network Upgrades, consistent with all standards and requirements set forth by the FERC, ISO-NE, any other applicable Governmental Entity and the Interconnecting Utility.

(b) Seller shall defend, indemnify and hold Buyer harmless against any liability arising due to Seller's performance or failure to perform under the Interconnection Agreement.

3.7 New RPS Class I Renewable Generation Unit.

The Facility shall be a RPS Class I Renewable Generation Unit, qualified by the DOER as eligible to participate in the RPS program, under Section 11F of Chapter 25A of the Massachusetts General Laws (subject to Section 4.7(b) in the event of a change in Law affecting such qualification as a RPS Class I Renewable Generation Unit) and shall have a Commercial Operation Date, as verified by the DOER, on or after January 1, 2013.

4. DELIVERY OF PRODUCTS

4.1 Obligation to Sell and Purchase Products.

(a) Beginning on the Commercial Operation Date and subject to Section 4.1(b), Seller shall sell and Deliver, and Buyer shall purchase and receive, Buyer's Percentage Entitlement of the Products in accordance with the terms and conditions of this Agreement. The aforementioned obligations for Seller to sell and Deliver the Products and for Buyer to purchase and receive the same is unit contingent and shall be subject to the operation of the Facility.

(b) Buyer shall not be obligated to purchase any Products to the extent that such Products exceed the Contract Maximum Amount in any hour. In addition, Buyer shall not be obligated to purchase any REC or comparable certificate, credit, attribute or other similar product produced by the Facility which fails to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit, and, to the extent that Buyer does not purchase any such REC or comparable certificate, credit, attribute or other similar product produced by the Facility, Seller may, in its sole discretion, sell, transfer or otherwise dispose of that REC or comparable certificate, credit, attribute or other similar product. Once Buyer notifies Seller that it will not purchase any REC or comparable certificate, credit, attribute or other similar product produced by the Facility which fails to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit, then Buyer may resume purchasing such RECs or comparable certificates, credits, attributes or other similar products produced by the Facility upon thirty (30) days' prior written notice to Seller, unless otherwise agreed by Buyer and Seller.

(c) Seller shall Deliver Buyer's Percentage Entitlement of the Products produced by the Facility, up to and including the Contract Maximum Amount, exclusively to Buyer, and Seller shall not sell, divert, grant, transfer or assign such Products or any certificate or other attribute associated with such Products to any Person other than Buyer during the Term. Seller shall not enter into any agreement or arrangement under which such Products can be claimed by any Person other than Buyer. Buyer shall have the exclusive right to resell or convey the Products in its sole discretion.

(d) Prior to Seller or an Affiliate of Seller entering into a new bilateral agreement or an amendment to an existing agreement to sell any of the output of either the Facility or another generating facility owned in whole or in part by Seller or an Affiliate of Seller that utilizes any Common Infrastructure (a **"Companion Facility"**) to another Person, Seller shall first take the actions set forth in this Section 4.1(d), as follows:

(i) Where the term of such agreement is one (1) year or more, Seller shall first offer to Buyer in writing to amend this Agreement to incorporate the terms and conditions of such other agreement or amendment. Buyer shall have twenty (20) days to either: (1) accept all of the terms and conditions of such other agreement or amendment; or (2) accept only the pricing and term provisions included in such other agreement or amendment; or (3) decline all of the terms and conditions of such other agreement or amendment. In the event Buyer chooses either option (1) or (2) above, Seller and Buyer shall amend this Agreement to reflect the accepted terms and conditions and, to the extent Buyer determines such amendment requires MDPU approval or filing, Buyer shall use commercially reasonable efforts to apply for such approval or make such filing in accordance with Section 18. No amendment of this Agreement under this Section 4.1(d)(i) shall affect the quantity of Products to be received and purchased by Buyer under this Agreement.

(ii) Prior to Seller or an Affiliate of Seller entering into a new agreement to sell any of the output of the Facility or a Companion Facility to another Person where the term of such agreement is less than one (1) year, Seller or such Affiliate of Seller shall first offer to enter into such agreement for such output with Buyer on the same terms and conditions. Buyer shall have twenty (20) days to either accept or reject such agreement. In the event Buyer chooses to enter into such agreement, Buyer and Seller or such Affiliate of Seller shall promptly execute such agreement. To the extent Buyer determines such agreement requires MDPU approval or filing, Buyer will use commercially reasonable efforts to apply for such approval or make such filing consistent with Section 18, and such agreement shall not become effective unless and until such MDPU approval is obtained or such MDPU filing is made.

(iii) If Buyer fails to notify Seller of its choice within twenty (20) days after Buyer's receipt of the offer from Seller or an Affiliate of Seller under clause (i) or (ii) above, Buyer shall be deemed to have elected to decline all of the terms and conditions of such other agreement or amendment. If any required filing with or approval by the MDPU with respect to any amendment or agreement under this Section 4.1(d) as described above is not made or received within one hundred eighty (180) days after Buyer and Seller or an Affiliate of Seller enter into such amendment or agreement, then such amendment or agreement shall be void and of no further force and effect.

(iv) If Buyer declines to enter into a new agreement or an amendment to this Agreement under this Section 4.1(d) or the MDPU filing or approval relating to such agreement or amendment is not received within one hundred eighty (180) days after Buyer and Seller or an Affiliate of Seller enter into such agreement or amendment, then Seller or such Affiliate of Seller may proceed with the proposed sale of such output of the Facility or such Companion Facility to another Person under the terms and conditions offered to Buyer.

(v) This Section 4.1(d) shall only apply to bilateral agreements entered into on or before the tenth anniversary of the Commercial Operation Date. Any transactions conducted in ISO-NE's Real-Time or Day-Ahead markets and any bilateral agreements entered into after the tenth anniversary of the Commercial Operation Date shall not be subject to this Section 4.1(d).

4.2 Scheduling and Delivery.

(a) During the Services Term, Seller shall Schedule Deliveries of Energy hereunder with ISO-NE within the defined Operational Limitations of the Facility and in accordance with this Agreement, all ISO-NE Practices and ISO-NE Rules, as applicable. Seller shall transfer the Energy to Buyer in the Day Ahead Energy Market or Real Time Energy Market, as reasonably agreed from time to time by Buyer and Seller and consistent with prevailing electric industry practices at the time, in such a manner that Buyer may resell such Energy in the Day Ahead Energy Market or Real Time Energy Market, as applicable, and Buyer shall have no obligation to pay for any Energy not transferred to Buyer in the Day Ahead Energy Market or Real Time Energy Market or for which Buyer is not credited in the ISO-NE Settlement Market System (including, without limitation, as a result of an outage on any electric transmission system). In the event that the Locational Marginal Price ("LMP") for the Energy at the Delivery Point is less than $0.00 per MWh in any hour, Seller shall credit or reimburse Buyer (at Buyer's discretion) the difference between $0 and such negative LMP per MWh for that Energy for each such hour.

(b) The Parties agree to use commercially reasonable efforts to comply with all applicable ISO-NE Rules and ISO-NE Practices in connection with the Scheduling and

Delivery of Energy hereunder. Penalties or similar charges assessed by a Transmission Provider and caused by noncompliance with the Scheduling obligations set forth in this Section 4.2 shall be the responsibility of Seller.

(c) Without limiting the generality of this Section 4.2, Seller or the party with whom Seller contracts pursuant to Section 3.5(e) shall at all times during the Services Term be designated as the "Lead Market Participant" (or any successor designation) for the Facility and shall be solely responsible for any obligations and liabilities, including all charges, penalties and financial assurance obligations, imposed by ISO-NE or under the ISO-NE Rules and ISO-NE Practices with respect to the Facility.

4.3 Failure of Seller to Deliver Products. In the event that Seller fails to satisfy any of its obligations to Deliver any of the Products hereunder in accordance with Section 4.1 and Section 4.2, and such failure is not excused under the express terms of this Agreement (a **"Delivery Failure"**), Seller shall pay Buyer an amount for such Delivery Failure equal to the Cover Damages. Such payment shall be due no later than the date for Buyer's payment for the applicable month as set forth in Section 5.2 hereof; provided, however, that if Seller demonstrates to Buyer's reasonable satisfaction that such Delivery Failure was solely the result of an administrative error by Seller, such payment shall not be due until the later of the date for Buyer's payment for the applicable month as set forth in Section 5.2 hereof or the date that is fifteen (15) days after such Delivery Failure occurred. Each Party agrees and acknowledges that (i) the damages that Buyer would incur due to a Delivery Failure would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Cover Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.4 Failure by Buyer to Accept Delivery of Products. If Buyer fails to accept all or part of any of the Products to be purchased by Buyer hereunder and such failure to accept is not excused under the terms of this Agreement (a **"Rejected Purchase"**), then Buyer shall pay Seller, on the date payment would otherwise be due in respect of the month in which the failure occurred, an amount for such Rejected Purchase equal to the Resale Damages. Each Party agrees and acknowledges that (i) the damages that Seller would incur due to a Rejected Purchase would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Resale Damages as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

4.5 Delivery Point.

(a) All Energy shall be Delivered hereunder by Seller to Buyer at the Delivery Point. Seller shall be responsible for the costs of delivering its Energy to the Delivery Point consistent with all standards and requirements set forth by the FERC, ISO-NE and any other applicable Governmental Entity or tariff.

(b) Seller shall be responsible for all applicable charges associated with transmission interconnection, service and delivery charges, including all related ISO-NE administrative fees and other FERC-approved charges in connection with the Delivery of Energy to and at the Delivery Point.

(c) Buyer shall be responsible for all losses, transmission charges, ancillary service charges, line losses, congestion charges and other ISO-NE or applicable system costs or charges associated with transmission incurred, in each case, in connection with the transmission of Energy delivered under this Agreement from and after the Delivery Point.

4.6 Metering.

(a) Metering. All electric metering associated with the Facility, including the Facility meter and any other real-time meters, billing meters and back-up meters (collectively, the **"Meters"**), shall be installed, operated, maintained and tested at Seller's expense in accordance with Good Utility Practice and any applicable requirements and standards issued by NERC, the Interconnecting Utility, and ISO-NE; provided that each Meter shall be tested at Seller's expense once each Contract Year. The Meters shall be used for the registration, recording and transmission of information regarding the Energy output of the Facility. Seller shall provide Buyer with a copy of all metering and calibration information and documents regarding the Meters promptly following receipt thereof by Seller.

(b) Measurements. Readings of the Meters at the Facility by the Interconnecting Utility in whose territory the Facility is located (or an independent Person mutually acceptable to the Parties) shall be conclusive as to the amount of Energy generated by the Facility; provided however, that Seller, upon request of Buyer and at Buyer's expense (if more frequently than annually as provided for in Section 4.6(a)), shall cause the Meters to be tested by the Interconnecting Utility in whose territory the Facility is located, and if any Meter is out of service or is determined to be registering inaccurately by more than two percent (2%), (i) the measurement of Energy produced by the Facility shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, in accordance with the filed tariff of such Interconnecting Utility, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder and (ii) Seller shall reimburse Buyer for the cost of such test of the Meters. Meter readings shall be adjusted to take into account the losses to Deliver the Energy to the Delivery Point. Seller shall make recorded meter data available monthly to the Buyer at no cost.

(c) Inspection, Testing and Calibration. Buyer shall have the right to inspect and test any of the Meters at the Facility at reasonable times and upon reasonable notice from Buyer to Seller. Buyer shall have the right to have a representative present during any testing or calibration of the Meters at the Facility by Seller. Seller shall provide Buyer with timely notice of any such testing or calibration.

(d) Audit of Meters. Buyer shall have access to the Meters and the right to audit all information and test data related to such Meters.

(e) Notice of Malfunction. Seller shall provide Buyer with prompt notice of any malfunction or other failure of the Meters or other telemetry equipment necessary to accurately report the quantity of Energy being produced by the Facility. If any Meter is found to be inaccurate by more than two percent (2%), the meter readings shall be adjusted as far back as can reasonably be ascertained, but in no event shall such period exceed six (6) months from the date that such inaccuracy was discovered, and any adjustment shall be reflected in the next invoice provided by Seller to Buyer hereunder.

(f) Telemetry. The Meters shall be capable of sending meter telemetry data, and Seller shall provide Buyer with simultaneous access to such data at no additional cost to Buyer. This provision is in addition to Seller's requirements under ISO-NE Rules and Practices, including ISO-NE Operating Procedure No. 18

4.7 RECs.

(a) Seller shall transfer to Buyer all of the right, title and interest in and to Buyer's Percentage Entitlement of the Facility's Environmental Attributes, including the RECs, generated by the Facility during the Term in accordance with the terms of this Section 4.7.

(b) All Energy provided by Seller to Buyer from the Facility under this Agreement shall meet the requirements for eligibility pursuant to the RPS; provided, however, that if the Facility ceases to qualify as a RPS Class I Renewable Generation Unit solely as a result of a change in Law with respect to the RPS, Seller shall be required to use commercially reasonable efforts to ensure that all Energy provided by Seller to Buyer from the Facility under this Agreement meets the requirements for eligibility pursuant to the RPS after that change in Law.

(c) At Buyer's request and at Seller' sole cost, Seller shall also seek qualification under the renewable portfolio standard or similar law of New York, Connecticut and/or one or more additional New England states (in addition to Massachusetts) and/or any federal renewable energy standard. Seller shall use commercially reasonable efforts, consistent with Good Utility Practice, to maintain such qualification at all times during the Services Term, or until Buyer indicates such qualification is no longer necessary. Seller shall also submit any information required by any state or federal agency (including without limitation the MDPU) with regard to administration of its rules regarding Environmental Attributes or its renewable energy standard or renewable portfolio standard to Buyer or as directed by Buyer.

(d) Seller shall comply with all GIS Operating Rules relating to the creation and transfer of all RECs to be purchased by Buyer under this Agreement and all other GIS Operating Rules to the extent required for Buyer to achieve the full value of the RECs. In addition, at Buyer's request, Seller shall register with and comply with the rules and requirements of any other tracking system or program that tracks, monetizes or otherwise creates or enhances value for Environmental Attributes, which compliance shall be at Seller's sole cost if such registration and compliance is requested in connection with Section 4.7(c) above and shall be at Buyer's sole cost in other instances.

(e) Prior to the delivery of any Energy hereunder (including any Energy Delivered during the Test Period), either (i) Seller shall cause Buyer to be registered in the GIS as the initial owner of all Certificates to be Delivered hereunder to Buyer or (ii) Seller and Buyer shall effect an irrevocable forward transfer of the Certificates to be Delivered hereunder to Buyer in the GIS; provided, however, that no payment shall be due to Seller for any RECs until the

Certificates are actually deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing.

(f) The Parties intend for the transactions entered into hereunder to be physically settled, meaning that the RECs are intended to be Delivered in the GIS account of Buyer or its designee as set forth in this Section 4.7.

4.8 Deliveries During Test Period. During the Test Period, Seller shall sell and Deliver, and Buyer shall purchase and receive Buyer's Percentage Entitlement of any Energy and RECs produced by the Facility. Notwithstanding the provisions of Section 5.1, payment for Buyer's Percentage Entitlement of all Energy and RECs produced during the Test Period shall be equal to the product of (x) Buyer's Percentage Entitlement of the MWh of Energy delivered to the Delivery Point and (y) the Real Time Locational Marginal Price at such Delivery Point (as determined by ISO-NE) for each hour of the month when Energy and RECs are produced by the Facility. In no event shall the Test Period extend beyond six months, except due to Force Majeure.

5. PRICE AND PAYMENTS FOR PRODUCTS

5.1 Price for Products. All Products Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Price specified in Exhibit D; provided, however, that if the RECs fail to satisfy the RPS as an Environmental Attribute associated with the specified MWh of generation from a RPS Class I Renewable Generation Unit and Buyer does not purchase the RECs pursuant to Section 4.1(b), then all Energy Delivered to Buyer in accordance with this Agreement shall be purchased by Buyer at the Adjusted Price specified in Exhibit D. Other than the (i) payment for the Products under this Section 5.1, (ii) payments related to Meter testing under Section 4.6(b), (iii) payments related to Meter malfunctions under Section 4.6(e), (iv) payment for Energy and RECs during the Test Period in accordance with Section 4.8, (v) payment of any Resale Damages under Section 4.4, (vi) payment of interest on late payments under Section 5.3, (vii) payments for reimbursement of Buyer's Taxes under Section 5.4(a), (viii) return of any Credit Support under Section 6.3, and (ix) payment of any Termination Payment due from Buyer under Section 9.3, Buyer shall not be required to make any other payments to Seller under this Agreement, and Seller shall be solely responsible for all costs incurred by it in connection with the performance of its obligations under this Agreement.

5.2 Payment and Netting.

(a) Billing Period. The calendar month shall be the standard period for all payments under this Agreement. On or before the fifteenth (15th) day following the end of each month, Seller shall render to Buyer an invoice for the payment obligations incurred hereunder during the preceding month, based on the Energy Delivered in the preceding month, and any RECs deposited in Buyer's GIS account or a GIS account designated by Buyer to Seller in writing in the preceding month. Such invoice shall contain supporting detail for all charges reflected on the invoice, and Seller shall provide Buyer with additional supporting documentation and information as Buyer may request.

(b) Timeliness of Payment. All undisputed charges shall be due and payable in accordance with each Party's invoice instructions on or before the later of (x) fifteen (15) days from receipt of the applicable invoice or (y) the last day of the calendar month in which the applicable invoice was received (or in either event the next Business Day if such day is not a Business Day). Each Party shall make payments by electronic funds transfer, or by other mutually agreeable method(s), to the account designated by the other Party. Any undisputed amounts not paid by the due date shall be deemed delinquent and shall accrue interest at the Late Payment Rate, such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

(c) Disputes and Adjustments of Invoices.

(i) All invoices rendered under this Agreement shall be subject to adjustment after the end of each month in order to true-up charges based on changes resulting from recent ISO-NE billing statements or revisions, if any, to previous ISO-NE billing statements. If ISO-NE resettles any invoice which relates to the Products sold under this Agreement and (a) any charges thereunder are the responsibility of the other Party under this Agreement or (b) any credits issued thereunder would be due to the other Party under this Agreement, then the Party receiving the invoice from ISO-NE shall in the case of (a) above invoice the other Party or in the case of (b) above pay the amount due to the other Party. Any invoices issued or amounts due pursuant to this Section shall be invoiced or paid as provided in this Section 5.2.

(ii) A Party may, in good faith, dispute the correctness of any invoice or any adjustment to an invoice rendered under this Agreement, or adjust any invoice for any arithmetic or computational error within twelve (12) months of the date the invoice, or adjustment to an invoice, was rendered. In the event an invoice or portion thereof, or any other claim or adjustment arising hereunder, is disputed, payment of the undisputed portion of the invoice shall be required to be made when due, with notice of the dispute given to the other Party. Any invoice dispute or invoice adjustment shall be in writing and shall state the basis for the dispute or adjustment. Payment of the disputed amount shall not be required until the dispute is resolved. Upon resolution of the dispute, any required payment or refund shall be made within ten (10) days of such resolution along with interest accrued at the Late Payment Rate from and including the due date (or in the case of a refund, the payment date) but excluding the date paid. Inadvertent overpayments shall be reimbursed or deducted by the Party receiving such overpayment from subsequent payments, with interest accrued at the Late Payment Rate from and including the date of such overpayment to but excluding the date repaid or deducted by the Party receiving such overpayment, as directed by the other Party. Any dispute with respect to an invoice or claim to additional payment is waived unless the other Party is notified in accordance with this Section 5.2 within the referenced twelve (12) month period.

(d) Netting of Payments. The Parties hereby agree that they may discharge mutual debts and payment obligations due and owing to each other under this Agreement on the same date through netting, in which case all amounts owed by each Party to the other Party for the purchase and sale of Products during the monthly billing period under this Agreement, including any related damages calculated pursuant to this Agreement, interest, and payments or credits, may be netted so that only the excess amount remaining due shall be paid by the Party who owes it. If no mutual debts or payment obligations exist and only one Party owes a debt or obligation to the other during the monthly billing period, such Party shall pay such sum in full when due. The Parties agree to provide each other with reasonable detail of such net payment or net payment request.

5.3 Interest on Late Payment or Refund. A late payment charge shall accrue on any late payment or refund as specified above at the lesser of (a) the prime rate specified in the "Money Rates" section of The Wall Street Journal (or, if such rate is not published therein, in a successor index mutually selected by the Parties) plus 1% per cent, and (b) the maximum rate permitted by applicable Law in transactions involving entities having the same characteristics as the Parties (the **"Late Payment Rate"**).

5.4 Taxes, Fees and Levies.

(a) Seller shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with the Facility or delivery or sale of the Products ("**Seller's Taxes**"). Buyer shall be obligated to pay all present and future taxes, fees and levies, imposed on or associated with such Products after Delivery of such Products to Buyer or imposed on or associated with the purchase of such Products (other than ad valorem, franchise or income taxes which are related to the sale of the Products and are, therefore, the responsibility of Seller) ("**Buyer's Taxes**"). In the event Seller shall be required by law or regulation to remit or pay any Buyer's Taxes, Buyer shall reimburse Seller for such payment. In the event Buyer shall be required by law or regulation to remit or pay any Seller's Taxes, Seller shall reimburse Buyer for such payment, and Buyer may deduct any of the amount of any such Seller's Taxes from the amount due to Seller under Section 5.2. Buyer shall have the right to all credits, deductions and other benefits associated with taxes paid by Buyer or reimbursed to Seller by Buyer as described herein. Nothing shall obligate or cause a Party to pay or be liable to pay any taxes, fees and levies for which it is exempt under law.

(b) Seller shall bear all risks, financial and otherwise, throughout the Term, associated with Seller's or the Facility's eligibility to receive any federal or state tax credits, to qualify for accelerated depreciation for Seller's accounting, reporting or tax purposes, or to receive any other grant or subsidy from a Governmental Entity or other Person. The obligation of the Parties hereunder, including those obligations set forth herein regarding the purchase and Price for and Seller's obligation to deliver the Products, shall be effective regardless of whether the production and/or sale of the Products from the Facility is eligible for, or receives, any federal or state tax credits, grants or other subsidies or any particular accounting, reporting or tax treatment during the Term.

6. SECURITY FOR PERFORMANCE *[NSTAR/UNITIL/WMECO VERSION]*

6.1 Seller's Support.

(a) Seller shall be required to post Credit Support in the amount of [$_________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] to secure Seller's obligations in the period between the Effective Date and the Commercial Operation Date (**"Development Period Security"**). Fifty percent (50%) of the Development Period Security shall be provided to Buyer on the Effective Date; and the remaining fifty percent (50%) of the Development Period Security shall be provided to Buyer within fifteen (15) Business Days after receipt of the Regulatory Approval. If at any time prior to the Commercial Operation Date, the amount of Development Period Security is reduced as a result of Buyer's draw upon such Development Period Security to less than the amount of Development Period Security required to be provided by Seller through the period ending fifteen (15) days after receipt of the Regulatory Approval, Seller shall replenish such Development Period Security to the amount of Development Period Security required to be provided by Seller through the period ending fifteen (15) days after receipt of the Regulatory Approval within five (5) days of that draw. Buyer shall return any undrawn amount of the Development Period Security to Seller within thirty (30) days after the later of (x) Buyer's receipt of an undisputed notice from Seller that the Commercial Operation Date has occurred or (y) Buyer's receipt of the full amount of the Operating Period Security.

(b) Beginning not later than ten (10) days following the Commercial Operation Date, Seller shall provide Buyer with Credit Support to secure Seller's obligations under this Agreement after the Commercial Operation Date through and including the date that all of Seller's obligations under this Agreement are satisfied (**"Operating Period Security"**). The Operating Period Security shall be in an amount equal to [$_________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less]. If at any time on or after the Commercial Operation Date, the amount of Operating Period Security is reduced as a result of Buyer's draw upon such Operating Period Security, Seller shall replenish such Operating Period Security to the total amount required under this Section 6.1(b) within five (5) Business Days of that draw.

6.2 Cash Deposits. Any cash provided by Seller as Credit Support under this Agreement shall be held in an interest bearing deposit account selected by Buyer in its reasonable discretion. All interest accrued on that cash deposit shall be retained in that account; provided, however, that to the extent the amount held in that account exceeds the required level of Development Period Security (before and on the Commercial Operation Date) or the Operating Period Security (after the Commercial Operation Date), such excess shall be paid to

Seller promptly after Seller requests such a payment in writing delivered to Buyer. Seller agrees to comply with the commercially reasonable requirements of Buyer in connection with the receipt and retention of any cash provided as Credit Support under this Agreement.

6.3 Return of Credit Support. Any unused Credit Support provided under this Agreement shall be returned to the Party providing that Credit Support only after any such Credit Support has been used to satisfy any outstanding obligations of that Party in existence at the time of the expiration or termination of this Agreement. Provided such obligations have been satisfied, such Credit Support shall be returned to the Party providing it within thirty (30) days after the earlier of (a) the expiration of the Term of this Agreement or (b) termination of this Agreement under Section 8.3, Section 9.3(b) or Section 10.1(c).

6. SECURITY FOR PERFORMANCE *[NATIONAL GRID VERSION]*

6.1 Grant of Security Interest. Subject to the terms and conditions of this Agreement, Seller hereby pledges to Buyer as security for all outstanding obligations under this Agreement (other than indemnification obligations surviving the expiration of the Term) and any other documents, instruments or agreements executed in connection therewith (collectively, the **"Obligations"**), and grants to Buyer a first priority continuing security interest, lien on, and right of set-off against all Posted Collateral delivered to or received by Buyer hereunder. Upon the return by Buyer to Seller of any Posted Collateral, the security interest and lien granted hereunder on that Posted Collateral will be released immediately and, to the extent possible, without further action by either Party.

6.2 Seller's Support.

(a) Seller shall be required to post Credit Support in the amount of $[________] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less] to secure Seller's Obligations until the Commercial Operation Date (**"Development Period Security"**). Fifty percent (50%) of the Development Period Security shall be provided to Buyer on the Effective Date, and the remaining fifty percent (50%) of the Development Period Security shall be provided to Buyer within fifteen (15) days after the receipt of the Regulatory Approval. Buyer shall return any undrawn amount of the Development Period Security to Seller within thirty (30) days after the later of (x) Buyer's receipt of an undisputed notice from Seller that the Commercial Operation Date has occurred or (y) Buyer's receipt of the full amount of the Operating Period Security.

(b) Beginning not later than three (3) days following the Commercial Operation Date, Seller shall provide Buyer with Credit Support to secure Seller's Obligations after the Commercial Operation Date through and including the date that all of Seller's Obligations are satisfied ("**Operating Period Security**"). The Operating Period Security shall be in the amount of $[_______] [$30 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 50% or more; $20 per kwh of Contract Maximum Amount if the

Facility has an expected capacity factor more than 20% but less than 50%; and $10 per kwh of Contract Maximum Amount if the Facility has an expected capacity factor of 20% or less].

(c) The Credit Support Delivery Amount, as defined below, will be rounded up, and the Return Amount, as defined below, will be rounded down, in each case to the nearest integral multiple of $10,000 (**"Rounding Amount"**).

(d) The following items will qualify as "**Credit Support**" hereunder in the amount noted under "Valuation Percentage":

	"Valuation Percentage"
(A) Cash	100%
(B) Letters of Credit	100% unless either (i) a Letter of Credit Default shall have occurred and be continuing with respect to such Letter of Credit, or (ii) twenty (20) or fewer Business Days remain prior to the expiration of such Letter of Credit, in which cases the Valuation Percentage shall be 0%.

(e) All calculations with respect to Credit Support shall be made by the Valuation Agent as of the Valuation Time on the Valuation Date.

6.3 Delivery of Credit Support.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Buyer, and (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Buyer for which there exist any unsatisfied payment obligations with respect to Buyer, then Buyer may request, by written notice, that Seller Transfer to Buyer, or cause to be Transferred to Buyer, Credit Support for the benefit of Buyer, having a Value of at least the Collateral Requirement (**"Credit Support Delivery Amount"**). Such Credit Support shall be delivered to Buyer on the next Business Day if the request is received by the Notification Time; otherwise Credit Support is due by the close of business on the second Business Day after the request is received.

6.4 Reduction and Substitution of Posted Collateral.

On any Business Day during the Services Term on which (a) no Event of Default has occurred and is continuing with respect to Seller, (b) no termination date has occurred or has been designated as a result of an Event of Default with respect to Seller for which there exist any unsatisfied payment Obligations, and (c) the Posted Collateral posted by Seller exceeds the required Operating Period Security (rounding downwards for any fractional amount to the next interval of the Rounding Amount), then Seller may, at its sole cost, request that Buyer return Operating Period Security in the amount of such difference (**"Credit Support Return Amount"**) and Buyer shall be obligated to do so. Such Posted Collateral shall be returned to

Seller by the close of business on the second Business Day after Buyer's receipt of such request. The Parties agree that if Seller has posted more than one type of Credit Support to Buyer, Seller can, in its sole discretion, select the type of Credit Support for Buyer to return; provided, however, that Buyer shall not be required to return the specified Credit Support if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Operating Period Security.

6.5 Administration of Posted Collateral.

(a) Cash. Posted Collateral provided in the form of Cash to Buyer hereunder shall be subject to the following provisions.

(i) So long as no Event of Default has occurred and is continuing with respect to Buyer, Buyer will be entitled to either hold Cash or to appoint an agent which is a Qualified Institution (a **"Custodian"**) to hold Cash for Buyer. In the event that an Event of Default has occurred and is continuing with respect to Buyer, then the provisions of Section 6.5(a)(ii) shall not apply with respect to Buyer and Cash shall be held in a Qualified Institution in accordance with the provisions of Section 6.5(a)(iii)(B). Upon notice by Buyer to Seller of the appointment of a Custodian, Seller's Obligations to make any Transfer will be discharged by making the Transfer to that Custodian. The holding of Cash by a Custodian will be deemed to be the holding of Cash by Buyer for which the Custodian is acting. If Buyer or its Custodian fails to satisfy any conditions for holding Cash as set forth above, or if Buyer is not entitled to hold Cash at any time, then Buyer will Transfer, or cause its Custodian to Transfer, the Cash to a Qualified Institution and the Cash shall be maintained in accordance with Section 6.5(a)(iii)(B). Except as set forth in Section 6.5(c), Buyer will be liable for the acts or omissions of the Custodian to the same extent that Buyer would be held liable for its own acts or omissions.

(ii) Notwithstanding the provisions of applicable Law, if no Event of Default has occurred and is continuing with respect to Buyer and no termination date has occurred or been designated as a result of an Event of Default with respect to Buyer for which there exists any unsatisfied payment obligations with respect to Buyer, then Buyer shall have the right to sell, pledge, rehypothecate, assign, invest, use, comingle or otherwise use in its business any Cash that it holds as Posted Collateral hereunder, free from any claim or right of any nature whatsoever of Seller, including any equity or right of redemption by Seller.

(iii) Notwithstanding Section 6.5(a)(ii), if neither Buyer nor the Custodian is eligible to hold Cash pursuant to Section 6.5(a)(i) then:

(A) the provisions of Section 6.5(a)(ii) will not apply with respect to Buyer; and

(B) Buyer shall be required to Transfer (or cause to be Transferred) not later than the close of business within five (5) Business Days following the beginning of such ineligibility all Cash in its possession or held on its behalf to a Qualified Institution to be held in a segregated, safekeeping or custody account (the **"Collateral Account"**) within such Qualified Institution with the title of the account indicating that the property contained therein is being held as Cash for Buyer. The Qualified Institution shall serve as Custodian with respect to the Cash in the Collateral Account, and shall hold such Cash in accordance with the terms of this Article 6 and for the security interest of Buyer and execute such account control agreements as are necessary or applicable to perfect the security interest of Seller therein pursuant to Section 9-314 of the Uniform Commercial Code or otherwise, and subject to such security interest, for the ownership and benefit of Seller. The Qualified Institution holding the Cash will invest and reinvest or procure the investment and reinvestment of the Cash in accordance with the written instructions of Buyer, subject to the approval of such instructions by Seller (which approval shall not be unreasonably withheld). Buyer shall have no responsibility for any losses resulting from any investment or reinvestment effected in accordance with Seller's approval.

(iv) So long as no Event of Default with respect to Seller has occurred and is continuing, and no termination date has occurred or been designated for which any unsatisfied payment obligations of Seller exist as the result of an Event of Default with respect to Seller, in the event that Buyer or its Custodian is holding Cash, Buyer will Transfer (or cause to be Transferred) to Seller, in lieu of any interest or other amounts paid or deemed to have been paid with respect to such Cash (all of which shall be retained by Buyer), the Interest Amount. Interest on Cash shall accrue at the Collateral Interest Rate. Interest accrued during the previous month shall be paid by Buyer to Seller on the 3rd Business Day of each calendar month and on any Business Day that posted Credit Support in the form of Cash is returned to Seller, but solely to the extent that, after making such payment, the amount of the Posted Collateral will be at least equal to the required Development Period Security or Operating Period Security, as applicable. On or after the occurrence of an Event of Default with respect to Seller or a termination date as a result of an Event of Default with respect to Seller, Buyer or its Custodian shall retain any such Interest Amount as additional Posted Collateral hereunder until the Obligations of Seller under the Agreement have been satisfied in the case of a termination date or for so long as such Event of Default is continuing in the case of an Event of Default.

(b) Buyer's Rights and Remedies. If at any time an Event of Default with respect to Seller has occurred and is continuing, then, unless Seller has paid in full all of its Obligations that are then due, including those under Section 9.3(b) of this Agreement, Buyer may exercise one or more of the following rights and remedies: (i) all rights and remedies available to a secured party under applicable Law with respect to Posted Collateral held by Buyer, (ii) the right to set-off any amounts payable by Seller with respect to any Obligations against any Posted Collateral or the cash equivalent of any Posted Collateral held by Buyer, or (iii) the right to liquidate any Posted Collateral held by Buyer and to apply the proceeds of such liquidation of the Posted Collateral to any amounts payable to Buyer with respect to the Obligations in such order as Buyer may elect. For purposes of this Section 6.5, Buyer may draw on the undrawn portion of any Letter of Credit from time to time up to the amount of the Obligations that are due at the time of such drawing. Cash proceeds that are not applied to the Obligations shall be maintained in accordance with the terms of this Article 6. Seller shall remain liable for amounts due and owing to Buyer that remain unpaid after the application of Posted Collateral, pursuant to this Section 6.5.

(c) Seller's Rights and Remedies. If at any time a termination date has occurred or been designated as the result of an Event of Default with respect to Buyer and Buyer has provided Credit Support to Seller under Section 9.3(b), then unless Buyer has paid in full all of its obligations under Section 9.3(b) of this Agreement: (i) Seller may exercise all rights and remedies available to Seller under applicable Law with respect to any Posted Collateral provided by Buyer, (ii) Buyer will be obligated immediately to return all Posted Collateral provided by Seller, including any accrued interest to Seller, or (iii) to the extent that Posted Collateral provided by Seller, including any accrued interest, is not returned pursuant to (ii) above, Seller may set-off any amounts payable by Seller with respect to any Obligations against any posted Credit Support or the cash equivalent thereof or to the extent that Seller does not set off such amounts, withhold payment of any remaining amounts payable by Seller with respect to any obligations of Buyer, up to the value of the remaining posted Credit Support held by Buyer, until that posted Credit Support is Transferred to Seller. For avoidance of doubt, (i) Buyer will be obligated immediately to Transfer any Letter of Credit to Seller and (ii) Seller may do any one or more of the following: (x) to the extent that the Letter of Credit is not Transferred to Seller as required pursuant to (i) above, set-off any amounts payable by Seller with respect to any Obligations against any such Letter of Credit held by Buyer and, to the extent its rights to set-off are not exercised, withhold payment of any remaining amounts payable by Seller with respect to any Obligations, up to the value of any remaining posted Credit Support and the value of any Letter of Credit held by Buyer, until any such Posted Credit Support and such Letter of Credit is Transferred to Seller; and (y) exercise rights and remedies available to Seller under the terms of the Letter of Credit.

(d) Letters of Credit. Credit Support provided in the form of a Letter of Credit shall be subject to the following provisions.

(i) As one method of providing increased Credit Support, Seller may increase the amount of an outstanding Letter of Credit or establish one or more additional Letters of Credit.

(ii) Upon the occurrence of a Letter of Credit Default, Seller agrees to Transfer to Buyer either a substitute Letter of Credit or Cash, in each case on or before the first (1^{st}) Business Day after the occurrence thereof (or the third (3^{rd}) Business Day after the occurrence thereof if only clause (a) under the definition of Letter of Credit Default applies).

(iii) Notwithstanding Sections 6.3 and 6.4, (1) Buyer need not return a Letter of Credit unless the entire principal amount is required to be returned, (2) Buyer shall consent to a reduction of the principal amount of a Letter of Credit to the extent that a Credit Support Delivery Amount would not be created thereby (as of the time of the request or as of the last time the Credit Support Delivery Amount was determined), and (3) if there is more than one form of Posted Collateral when a Credit Support Return Amount is to be Transferred, the Secured Party may elect which to Transfer.

(e) Care of Posted Collateral. Each Party shall exercise reasonable care to assure the safe custody of all Posted Collateral to the extent required by applicable Law, and in any event a Party will be deemed to have exercised reasonable care if it exercises at least the same degree of care as it would exercise with respect to its own property. Except as specified in the preceding sentence, each Party will have no duty with respect to the Posted Collateral, including without limitation, any duty to enforce or preserve any rights thereto.

(f) Substitutions. Unless otherwise prohibited herein, upon notice to Buyer specifying the items of Posted Collateral to be exchanged, Seller may, on any Business Day, deliver to Buyer other Credit Support (**"Substitute Credit Support"**). On the Business Day following the day on which the Substitute Credit Support is delivered to Buyer, Buyer shall return to Seller the items of Credit Support specified in Seller's notice; provided, however, that Buyer shall not be required to return the specified Posted Collateral if immediately after such return, Seller would be required to post additional Credit Support pursuant to the calculation of Development Period Security or Operating Period Security set forth in Sections 6.2(a) and 6.2(b), respectively.

6.6 Exercise of Rights Against Posted Collateral

(a) Disputes regarding amount of Credit Support. If either Party disputes the amount of Credit Support to be provided or returned (such Party the "**Disputing Party**"), then the Disputing Party shall (a) deliver the undisputed amount of Credit Support to the other Party (such Party, the "**Requesting Party**") and (b) notify the Requesting Party of the existence and nature of the dispute no later than 5:00 p.m. Eastern Prevailing Time on the Business Day that the request for Credit Support was made (the "**Request Date**"). On the Business Day following the Request Date, the Parties shall consult with each other in order to reconcile the two conflicting amounts. If the Parties are not able to resolve their dispute, the Credit Support shall be recalculated, on the Business Day following the Request Date, by each Party requesting quotations from two (2) Reference Market-Makers for a total of four (4) quotations. The highest and lowest of the four (4) quotations shall be discarded and the arithmetic average shall be taken of the remaining two (2), which shall be used in order to determine the amount of Credit Support required. On the same day the Credit Support amount is recalculated, the Disputing Party shall deliver any additional Credit Support required pursuant to the recalculation or the Requesting Party shall return any excess Credit Support that is no longer required pursuant to the recalculation.

(b) Further Assurances. Promptly following a request by a Party, the other Party shall use commercially reasonable efforts to execute, deliver, file, and/or record any financing statement, specific assignment, or other document and take any other action that may be necessary or desirable to create, perfect, or validate any security interest or lien, to enable the requesting party to exercise or enforce its rights or remedies under this Agreement, or to effect or document a release of a security interest on posted Credit Support or accrued interest.

(c) Further Protection. Seller will promptly give notice to Buyer of, and defend against, any suit, action, proceeding, or lien (other than a banker's lien in favor of the Custodian appointed by Buyer so long as no amount owing from Seller to such Custodian is overdue) that involves the Posted Collateral delivered to Buyer by Seller or that could adversely affect any security interest or lien granted pursuant to this Agreement.

7. REPRESENTATIONS, WARRANTIES, COVENANTS AND ACKNOWLEDGEMENTS

7.1 Representations and Warranties of Buyer. Buyer hereby represents and warrants to Seller as follows:

(a) Organization and Good Standing; Power and Authority. Buyer is a corporation duly incorporated, validly existing and in good standing under the laws of Massachusetts. Subject to the receipt of the Regulatory Approval, Buyer has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Due Authorization; No Conflicts. The execution and delivery by Buyer of this Agreement, and the performance by Buyer of its obligations hereunder, have been duly authorized by all necessary actions on the part of Buyer and do not and, under existing facts and Law, shall not: (i) contravene its certificate of incorporation or any other governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) assuming receipt of the Regulatory Approvals, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing.

(c) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Buyer and, assuming the due execution hereof and performance hereunder by Seller and receipt of the Regulatory Approval, constitutes a legal, valid and binding obligation of Buyer, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(d) No Proceedings. Except to the extent relating to the Regulatory Approval, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Buyer or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Buyer reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Buyer's ability to perform its obligations under this Agreement.

(e) Consents and Approvals. Except to the extent associated with the Regulatory Approval, the execution, delivery and performance by Buyer of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken or that shall be duly obtained, made or taken on or prior to the date required, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable as required under applicable Law.

(f) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Buyer.

(g) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Buyer, or, to Buyer's knowledge, threatened against it.

(h) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Buyer of its obligations under this Agreement.

7.2 Representations and Warranties of Seller. Seller hereby represents and warrants to Buyer as of the Effective Date as follows:

(a) Organization and Good Standing; Power and Authority. Seller is a [______________], validly existing and in good standing under the laws of [___________]. Subject to the receipt of the Permits listed in Exhibit B, Seller has all requisite power and authority to execute, deliver, and perform its obligations under this Agreement.

(b) Authority. Seller (i) has the power and authority to own and operate its businesses and properties, to own or lease the property it occupies and to conduct the business in which it is currently engaged; (ii) is duly qualified and in good standing under the laws of each jurisdiction where its ownership, lease or operation of property or the conduct of its business requires such qualification; and (iii) holds, as of the Effective Date, or shall hold by the Commercial Operation Date, all rights and entitlements necessary to construct, own and operate the Facility and to deliver the Products to the Buyer in accordance with this Agreement.

(c) Due Authorization; No Conflicts. The execution and delivery by Seller of this Agreement, and the performance by Seller of its obligations hereunder, have been duly authorized by all necessary actions on the part of Seller and do not and, under existing facts and Law, shall not: (i) contravene any of its governing documents; (ii) conflict with, result in a breach of, or constitute a default under any note, bond, mortgage, indenture, deed of trust, license, contract or other agreement to which it is a party or by which any of its properties may be bound or affected; (iii) assuming receipt of the Permits listed on Exhibit B, violate any order, writ, injunction, decree, judgment, award, statute, law, rule, regulation or ordinance of any Governmental Entity or agency applicable to it or any of its properties; or (iv) result in the creation of any lien, charge or encumbrance upon any of its properties pursuant to any of the foregoing.

(d) Binding Agreement. This Agreement has been duly executed and delivered on behalf of Seller and, assuming the due execution hereof and performance hereunder by Seller and receipt of the Permits listed on Exhibit B, constitutes a legal, valid and binding obligation of Seller, enforceable against it in accordance with its terms, except as such enforceability may be limited by law or principles of equity.

(e) No Proceedings. Except to the extent associated with the Permits listed on Exhibit B, there are no actions, suits or other proceedings, at law or in equity, by or before any Governmental Entity or agency or any other body pending or, to the best of its knowledge, threatened against or affecting Seller or any of its properties (including, without limitation, this Agreement) which relate in any manner to this Agreement or any transaction contemplated hereby, or which Seller reasonably expects to lead to a material adverse effect on (i) the validity or enforceability of this Agreement or (ii) Seller's ability to perform its obligations under this Agreement.

(f) Consents and Approvals. Subject to the receipt of the Permits listed on Exhibit B on or prior to the date such Permits are required under applicable Law, the execution, delivery and performance by Seller of its obligations under this Agreement do not and, under existing facts and Law, shall not, require any Permit or any other action by, any Person which has not been duly obtained, made or taken, and all such approvals, consents, permits, licenses, authorizations, filings, registrations and actions are in full force and effect, final and non-appealable. To Seller's knowledge, Seller shall be able to receive the Permits listed in Exhibit B in due course and as required under applicable Law to the extent that those Permits have not previously been received.

(g) New RPS Class I Renewable Generation Unit. The Facility shall be an RPS Class I Renewable Generation Unit, qualified by the DOER as eligible to participate in the RPS program, under Section 11F of Chapter 25A (subject to Section 4.7(b) in the event of a change in Law affecting such qualification as a RPS Class I Renewable Generation Unit) and shall have a commercial operation date, as verified by the DOER, on or after January 1, 2013.

(h) Title to Products. Seller has and shall have good and marketable title to all Products sold and Delivered to Buyer under this Agreement, free and clear of all liens, charges and encumbrances. Seller has not sold and shall not sell any such Products to any other Person, and no Person other than Seller can claim an interest in any Product to be sold to Buyer under this Agreement.

(i) Negotiations. The terms and provisions of this Agreement are the result of arm's length and good faith negotiations on the part of Seller.

(j) Bankruptcy. There are no bankruptcy, insolvency, reorganization, receivership or other such proceedings pending against or being contemplated by Seller, or, to Seller's knowledge, threatened against it.

(k) No Default. No Default or Event of Default has occurred and is continuing and no Default or Event of Default shall occur as a result of the performance by Seller of its obligations under this Agreement.

7.3 Continuing Nature of Representations and Warranties. The representations and warranties set forth in this Section are made as of the Effective Date and deemed made continually throughout the Term. If at any time during the Term, any Party obtains actual knowledge of any event or information which causes any of the representations and warranties in this Article 7 to be materially untrue or misleading, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

8. REGULATORY APPROVAL

8.1 Receipt of Regulatory Approval. The obligations of the Parties to perform this Agreement, other than the Parties' obligations under Section 6.1, Section 6.2, Section 8.2, Section 8.3 and Section 12, are conditioned upon and shall not become effective or binding until the receipt of the Regulatory Approval. Buyer shall notify Seller within five (5) Business Days after receipt of the Regulatory Approval or receipt of an order of the MDPU regarding this Agreement that is not acceptable in form and substance to Buyer in its sole discretion.

8.2 Filing for Regulatory Approval. Buyer shall use commercially reasonable efforts to (i) file an application for the Regulatory Approval with the MDPU by not later than [________] [30 days from Effective Date] and (ii) at Buyer's sole discretion, exercise commercially reasonable efforts to obtain the Regulatory Approval, including using commercially reasonable efforts to obtain a favorable resolution in any appeal of an order of the MDPU with respect to this Agreement; provided that Buyer shall have no obligation to appeal a MDPU order that it determines is unacceptable. Seller shall have the right to intervene in the proceeding before the MDPU and shall use commercially reasonable efforts to cooperate with Buyer (but only as requested by Buyer) in obtaining the Regulatory Approval.

8.3 Failure to Obtain Regulatory Approval. If Buyer (i) on any date notifies Seller that it has received an order of the MDPU regarding this Agreement that is not acceptable in form and substance to Buyer in its sole discretion or (ii) has not notified Seller that it has received the Regulatory Approval by [_______] [300 days from Effective Date], either Party may terminate this Agreement within thirty (30) days after such date by delivery of written notice to the other Party in accordance with Section 17. Upon such termination, neither Party shall have any further liability hereunder except for any obligations arising under Sections 6.3 and 12 which accrued prior to such termination.

9. BREACHES; REMEDIES

9.1 Events of Default by Either Party. It shall constitute an event of default (**"Event of Default"**) by either Party hereunder if:

(a) Representation or Warranty. Any material breach of any representation or warranty of such Party set forth herein, or in filings or reports made pursuant to this Agreement, and such breach continues for more than thirty (30) days after the Non-Defaulting Party has provided written notice to the Defaulting Party that any material representation or warranty set forth herein is false, misleading or erroneous in any material respect without the breach having been cured; or

(b) Payment Obligations. Any undisputed payment due and payable hereunder is not made on the date due, and such failure continues for more than ten (10) Business Days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; or

(c) Other Covenants. Other than a Delivery Failure (the sole remedy for which shall be the payment of Cover Damages under Section 4.3), a Rejected Purchase (the sole remedy for which shall be the payment of Resale Damages under 4.4), or an Event of Default described in Section 9.1(a), 9.1(b), 9.1(d), 9.1(e) or 9.2, such Party fails to perform, observe or otherwise to comply with any obligation hereunder and such failure continues for more than thirty (30) days after notice thereof is given by the Non-Defaulting Party to the Defaulting Party; provided, however, that such period shall be extended for an additional reasonable period if the Defaulting Party is unable to cure within that thirty (30) day period and provided that corrective action has been taken by the Defaulting Party within such thirty (30) day period and so long as such cure is diligently pursued by the Defaulting Party until such Default had been corrected, but in any event within one hundred fifty (150) days; or

(d) Bankruptcy. Such Party (i) is adjudged bankrupt or files a petition in voluntary bankruptcy under any provision of any bankruptcy law or consents to the filing of any bankruptcy or reorganization petition against such Party under any such law, or (without limiting the generality of the foregoing) files a petition to reorganize pursuant to 11 U.S.C. § 101 or any similar statute applicable to such Party, as now or hereinafter in effect, (ii) makes an assignment for the benefit of creditors, or admits in writing an inability to pay its debts generally as they become due, or consents to the appointment of a receiver or liquidator or trustee or assignee in bankruptcy or insolvency of such Party, or (iii) is subject to an order of a court of competent jurisdiction appointing a receiver or liquidator or custodian or trustee of such Party or of a major part of such Party's property, which is not dismissed within sixty (60) days; or

(e) Permit Compliance. Such Party fails to obtain and maintain in full force and effect any Permit (other than the Regulatory Approval) necessary for such Party to perform its obligations under this Agreement.

9.2 Events of Default by Seller. In addition to the Events of Default described in Section 9.1, it shall constitute an Event of Default by Seller hereunder if:

(a) Taking of Facility Assets. Any asset of Seller that is material to the construction, operation or maintenance of the Facility or the performance of its obligations hereunder is taken upon execution or by other process of law directed against Seller, or any such asset is taken upon or subject to any attachment by any creditor of or claimant against Seller and such attachment is not disposed of within sixty (60) days after such attachment is levied; or

(b) Failure to Maintain Credit Support. The failure of Seller to provide, maintain and/or replenish the Development Period Security or the Operating Period Security as required pursuant to Article 6 of this Agreement, and such failure continues for more than five (5) Business Days after Buyer has provided written notice thereof to Seller; or

(c) Energy Output. The failure of the Facility to produce Energy for twenty-four (24) consecutive months during the Services Term for any reason, including due in whole or in part to a Force Majeure; or

(d) Failure to Satisfy ISO-NE Obligations. The failure of Seller to satisfy, or cause to be satisfied (other than by Buyer), any material obligation under the ISO-NE Rules or ISO-NE Practices or any other material obligation with respect to ISO-NE, and such failure has a material adverse effect on the Facility or Seller's ability to perform its obligations under this Agreement or on Buyer or Buyer's ability to receive the benefits under this Agreement, provided that if Seller's failure to satisfy any material obligation under the ISO-NE Rules or ISO-NE Practices does not have a material adverse effect on Buyer or Buyer's ability to receive the benefits under this Agreement, Seller may cure such failure within thirty (30) days of its occurrence; or

(e) Failure to Meet Critical Milestones. The failure of Seller to satisfy any Critical Milestone by the date set forth therefor in Section 3.1(a), as the same may be extended in accordance with Section 3.1(c).

9.3 Remedies.

(a) Suspension of Performance and Remedies at Law. Upon the occurrence and during the continuance of an Event of Default, the Non-Defaulting Party shall have the right, but not the obligation, to (i) withhold any payments due the Defaulting Party under this Agreement, (ii) suspend its performance hereunder, and (iii) exercise such other remedies as provided for in this Agreement or, to the extent not inconsistent with the terms of this Agreement, at law, including, without limitation, the termination right set forth in Section 9.3(b). In addition to the foregoing, the Non-Defaulting Party shall retain its right of specific performance to enforce the Defaulting Party's obligations under this Agreement.

(b) Termination and Termination Payment. Upon the occurrence of an Event of Default, a Non-Defaulting Party may terminate this Agreement at its sole discretion by providing written notice of such termination to the Defaulting Party. If the Non-Defaulting Party terminates this Agreement, it shall be entitled to calculate and receive as its sole remedy for such Event of Default a **"Termination Payment"** as follows:

(i) *Termination by Buyer Prior to Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring prior to the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the sum of (x) all Delay Damages due and owing by Seller through the date of such termination plus (y) the undrawn amount of any Development Period Security provided to Buyer by Seller.

(ii) *Termination by Seller Prior to Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer prior to the Commercial Operation Date, Seller shall only receive a Termination Payment if the Commercial Operation Date either occurs by the date set forth therefor in Section 3.1(a) (as the same may be extended in accordance with Section 3.1(c)) or would have occurred by such date but for the Event of Default by Buyer giving rise to the termination of this Agreement. In such case, (x) if Seller terminates this Agreement because of an Event of Default by Buyer prior to the Financial Closing Date, the Termination Payment due to Seller shall be equal to the lesser of: (i) all of Seller's out-of-pocket expenses incurred in connection with the development and construction of the Facility prior to such termination and (ii) the Termination Payment due to Seller shall be calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller; and (y) if Seller terminates this Agreement because of an Event of Default by Buyer on or after the Financial Closing Date, the Termination Payment due to Seller shall be calculated according to the methodology in Section 9.3(b)(iv), as if the Commercial Operation Date had occurred prior to the date of the termination by Seller.

(iii) *Termination by Buyer On or After Commercial Operation Date*. If Buyer terminates this Agreement because of an Event of Default by Seller occurring on or after the Commercial Operation Date, the Termination Payment due to Buyer shall be equal to the amount, if positive, calculated according to the following formula:

(x) the present value, discounted at a rate equal to the prime rate specified in the "Money Rates" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (i) the amount, if, any, by which the forward market price of Energy and Renewable Energy Credits, as determined by the average of the quotes of at least two nationally recognized energy consulting firms chosen by Buyer, for Replacement Energy and Replacement RECs, exceeds the applicable Price that would have been paid pursuant to Exhibit D of this Agreement, multiplied by (ii) the projected Energy output of the Facility as determined by a recognized third party expert selected by Buyer, using a probability of exceedance basis of 50%; plus, (y) any reasonable incidental costs incurred by Buyer as a result of the Event of Default and termination of the Agreement

All such amounts shall be determined by Buyer in good faith and in a commercially reasonable manner, and Buyer shall provide Seller with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iii).

(iv) *Termination by Seller On or After Commercial Operation Date*. If Seller terminates this Agreement because of an Event of Default by Buyer occurring on or after the Commercial Operation Date, the Termination Payment due to Seller shall be equal to the amount, if positive, calculated according to the following formula:

(x) the present value, discounted at a rate equal to the prime rate specified in the "Money Rates" section of *The Wall Street Journal* determined as of the date of the notice of default, plus 300 basis points, for each month remaining in the Services Term, of (i) the amount, if, any, by which the applicable Price that would have been paid pursuant to Exhibit D of this Agreement, exceeds the forward market price of energy and Renewable Energy Credits as determined by the average of the quotes of at least two nationally recognized energy consulting firms chosen by Seller, for Replacement Energy and Replacement RECs, multiplied by (ii) the projected Energy output of the Facility as determined by a recognized third party expert selected by Seller using a probability of exceedance basis of 50%; plus, (y) any reasonable incidental costs incurred by Seller as a result of the Event of Default and termination of the Agreement.

All such amounts shall be determined by Seller in good faith and in a commercially reasonable manner, and Seller shall provide Buyer with a reasonably detailed calculation of the Termination Payment due under this Section 9.3(b)(iv).

(v) *Acceptability of Liquidated Damages*. Each Party agrees and acknowledges that (i) the damages that the Parties would incur due to an Event of Default would be difficult or impossible to predict with certainty, and (ii) it is impractical and difficult to assess actual damages in the circumstances stated, and therefore the Termination Payment as agreed to by the Parties and set forth herein is a fair and reasonable calculation of such damages.

(vi) *Payment of Termination Payment*. The Defaulting Party shall make the Termination Payment within ten (10) Business Days after such notice is effective. If the Defaulting Party disputes the Non-Defaulting Party's calculation of the Termination Payment, in whole or in part, the Defaulting Party shall, within ten (10) Business Days of receipt of the calculation of the Termination Payment, provide to the Non-Defaulting Party a detailed written explanation of the basis for such dispute; provided, however, the Defaulting Party shall first transfer Credit Support to the Non-Defaulting Party in an amount equal to the Termination Payment as calculated by the Non-Defaulting Party. If the Parties are unable to resolve the dispute within thirty (30) days, Article 11 shall apply.

(vii) *Use and Return of Credit Support*. In the event that the Defaulting Party fails to pay the Termination Payment in full within the time period set forth in Section 9.3(b)(vii), the Non-Defaulting Party may draw upon any Credit Support provided by the Defaulting Party to satisfy the unpaid portion of the Termination Payment. Upon the payment of the Termination Payment in full, any undrawn Credit Support shall be promptly returned to each Party providing that Credit Support.

(viii) *Reinstatement of Agreement*. In the event that Buyer terminates this Agreement prior to the Commercial Operation Date pursuant to Section 9.3(b)(i) and Seller thereafter achieves the Commercial Operation Date within one (1) year after such termination, Buyer may elect to reinstate this Agreement in accordance with its terms by providing Seller with at least six (6) months' prior written notice of such reinstatement. Upon such reinstatement, Buyer shall return to Seller any Termination Payment made by Seller, together with interest accruing at the Late Payment Rate, on or prior to the date selected for reinstatement of this Agreement.

(c) Set-off. The Non-Defaulting Party shall be entitled, at its option and in its discretion, to withhold and set off any amounts owed by the Non-Defaulting Party to the Defaulting Party against any payments and any other amounts owed by the Defaulting Party to the Non-Defaulting Party, including any Termination Payment payable as a result of any early termination of this Agreement.

(d) Notice to Lenders. Buyer shall provide a copy of any notice given to Seller under this Section 9 to one, but not more than one, Lender of which Buyer shall have written notice, and Buyer shall afford such Lender the same opportunities to cure Events of Default under this Agreement as are provided to Seller hereunder.

(e) Limitation of Remedies, Liability and Damages. EXCEPT AS EXPRESSLY SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. UNLESS EXPRESSLY HEREIN PROVIDED, NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS

INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

10. FORCE MAJEURE

10.1 Force Majeure.

(a) The term **"Force Majeure"** means an unusual, unexpected and significant event: (i) that was not within the control of the Party claiming its occurrence; (ii) that could not have been prevented or avoided by such Party through the exercise of reasonable diligence; and (iii) that directly prohibits or prevents such Party from performing its obligations under this Agreement. Under no circumstances shall Force Majeure include (w) any occurrence or event that merely increases the costs or causes an economic hardship to a Party, (x) any occurrence or event that was caused by or contributed to by the Party claiming the Force Majeure, (y) Seller's ability to sell the Products at a price greater than that set out in this Agreement, or (z) Buyer's ability to procure the Products at a price lower than that set out in this Agreement. In addition, a delay or inability to perform attributable to a Party's lack of preparation, a Party's failure to timely obtain and maintain all necessary Permits (excepting the Regulatory Approval), a failure to satisfy contractual conditions or commitments, or lack of or deficiency in funding or other resources shall each not constitute a Force Majeure.

(b) If either Party is unable, wholly or in part, by Force Majeure to perform obligations under this Agreement, such performance shall be excused and suspended so long as the circumstances that give rise to such inability exist, but for no longer period. The Party whose performance is affected shall give prompt notice thereof; such notice may be given orally or in writing but, if given orally, it shall be promptly confirmed in writing, providing details regarding the nature, extent and expected duration of the Force Majeure, its anticipated effect on the ability of such Party to perform obligations under this Agreement, and the estimated duration of any interruption in service or other adverse effects resulting from such Force Majeure, and shall be updated or supplemented to keep the other Party advised of the effect and remedial measures being undertaken to overcome the Force Majeure. Such inability shall be promptly corrected to the extent it may be corrected through the exercise of due diligence. Neither party shall be liable for any losses or damages arising out of a suspension of performance that occurs because of Force Majeure.

(c) Notwithstanding the foregoing, if the Force Majeure prevents full or partial performance under this Agreement for a period of twelve (12) months or more, the Party whose performance is not prevented by Force Majeure shall have the right to terminate this Agreement upon written notice to the other Party and without further recourse.

(d) Neither Party may raise a claim of Force Majeure based in whole or in part on curtailment by a Transmission Provider unless (i) such Party has contracted for firm transmission with a Transmission Provider for the Energy to be delivered to or received at the Delivery Point and (ii) such curtailment is due to "force majeure" or "uncontrollable force" or a similar term as defined under the Transmission Provider's tariff; provided, however, that existence of the foregoing factors shall not be sufficient to conclusively or presumptively prove the existence of a Force Majeure absent a showing of other facts and circumstances which in the aggregate with such factors establish that a Force Majeure as defined in Section 10.1(a) has occurred.

11. DISPUTE RESOLUTION

11.1 Dispute Resolution. In the event of any dispute, controversy or claim between the Parties arising out of or relating to this Agreement (collectively, a **"Dispute"**), the Parties shall attempt in the first instance to resolve such Dispute through consultations between the Parties. If such consultations do not result in a resolution of the Dispute within fifteen (15) days after notice of the Dispute has been delivered to either Party, then such Dispute shall be referred to the senior management of the Parties for resolution. If the Dispute has not been resolved within fifteen (15) days after such referral to the senior management of the Parties, then the Parties may seek to resolve such Dispute in the courts of the Commonwealth of Massachusetts; provided, however, if the Dispute is subject to FERC's jurisdiction over wholesale power contracts, then either Party may elect to proceed with the mediation through the FERC's Dispute Resolution Service; provided, however, that if one Party fails to participate in the negotiations as provided in this Section 11.1, the other Party can initiate mediation prior to the expiration of the thirty (30) Business Days. Unless otherwise agreed, the Parties will select a mediator from the FERC panel. The procedure specified herein shall be the sole and exclusive procedure for the resolution of Disputes. To the fullest extent permitted by law, any mediation proceeding and the settlement shall be maintained in confidence by the Parties.

11.2 Allocation of Dispute Costs. The fees and expenses associated with mediation shall be divided equally between the Parties, and each Party shall be responsible for its own legal fees, including but not limited to attorney fees, associated with any Dispute. The Parties may, by written agreement signed by both Parties, alter any time deadline, location(s) for meeting(s), or procedure outlined herein or in the FERC's rules for mediation.

11.3 Consent to Jurisdiction. Subject to Section 11.1, the Parties agree to the exclusive jurisdiction of the state and federal courts located in the Commonwealth of Massachusetts for any legal proceedings that may be brought by a Party arising out of or in connection with any Dispute.

11.4 Waiver of Jury Trial. EACH PARTY HEREBY WAIVES TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY SUIT, ACTION OR PROCEEDING ARISING OUT OF, RESULTING FROM OR IN ANY WAY RELATING TO THIS AGREEMENT

12. CONFIDENTIALITY

12.1 Nondisclosure. Buyer and Seller each agrees not to disclose to any Person and to keep confidential, and to cause and instruct its Affiliates, officers, directors, employees, partners and representatives not to disclose to any Person and to keep confidential, any non-public information relating to the terms and provisions of this Agreement, and any information relating to the Products to be supplied by Seller hereunder, and such other non-public information that is designated as "Confidential." Notwithstanding the foregoing, any such information may be disclosed:

(a) to the extent Buyer determines it is appropriate in connection with efforts to obtain or maintain the Regulatory Approval or to seek rate recovery for amounts expended by Buyer under this Agreement;

(b) as required by applicable laws, regulations, rules or orders or by any subpoena or similar legal process of any Governmental Entity so long as the receiving Party gives the non-disclosing Party written notice at least three (3) Business Days prior to such disclosure, if practicable;

(c) to the Affiliates of either Party and to the consultants, attorneys, auditors, financial advisors, lenders or potential lenders and their advisors of either Party or their Affiliates, but solely to the extent they have a need to know that information;

(d) in order to comply with any rule or regulation of ISO-NE, any stock exchange or similar Person or for financial disclosure purposes;

(e) to the extent the non-disclosing Party shall have consented in writing prior to any such disclosure; and

(f) to the extent that the information was previously made publicly available other than as a result of a breach of this Section 12.1;

provided, however, in each case, that the Party seeking such disclosure shall, to the extent practicable, use commercially reasonable efforts to prevent or limit the disclosure. The Parties shall be entitled to all remedies available at law or in equity to enforce or seek relief in connection with this Section 12.1.

12.2 Public Statements. No public statement, press release or other voluntary publication regarding this Agreement or the transactions to be made hereunder shall be made or issued without the prior consent of the other Party.

13. INDEMNIFICATION

Seller shall indemnify, defend and hold Buyer and its partners, shareholders, directors, officers, employees and agents (including, but not limited to, Affiliates and contractors and their employees), harmless from and against all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever arising from or related to Seller's execution, delivery or performance of this Agreement, or Seller's negligence, gross negligence, or willful misconduct, or Seller's failure to satisfy any obligation or liability under this Agreement. Buyer shall not indemnify, defend or hold harmless Seller or its partners, members, shareholders, directors, officers, managers employees or agents from and against any liabilities, damages, losses, penalties, claims, demands, suits or proceedings claimed by, due to or instituted by any third party as a result of either Party's execution, delivery or performance of this Agreement.

14. ASSIGNMENT AND CHANGE OF CONTROL

14.1 Prohibition on Assignments. Except as permitted under this Section 14, this Agreement may not be assigned by either Party without the prior written consent of the other Party, which consent may not be unreasonably withheld, conditioned or delayed. When assignable, this Agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assignees of the Parties, except that no assignment, pledge or other transfer of this Agreement by either Party shall operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement unless the other Party (or its successors or assigns) consents in writing to the assignment, pledge or other transfer and expressly releases the assignor, pledgor, or transferor from its obligations thereunder.

14.2 Permitted Assignment by Seller. Seller may pledge or assign the Facility, this Agreement or the revenues under this Agreement to any Lender as security for the project financing of the Facility, subject to Buyer's execution of a consent to assignment that is in form and substance reasonably satisfactory to Seller and such Lender that incorporates terms and conditions customary for a transaction of this type (including the provisions included in Section 9.3(d)); provided, however, that Buyer shall not be obligated to enter into any consent which shall adversely affect Buyer's rights or obligations under this Agreement. Buyer shall not unreasonably withhold, condition or delay providing its consent to an assignment to a Lender.

14.3 Change in Control over Seller. Buyer's consent shall be required for any change in Control over Seller, which consent shall not be unreasonably withheld, conditioned or delayed and shall be provided if Buyer reasonably determines that such change in Control does not have a material adverse effect on Seller's creditworthiness or Seller's ability to perform its obligations under this Agreement.

14.4 Permitted Assignment by Buyer. Buyer shall have the right to assign this Agreement without consent of Seller (a) in connection with any merger or consolidation of the Buyer with or into another Person or any exchange of all of the common stock or other equity interests of Buyer or Buyer's parent for cash, securities or other property or any acquisition, reorganization, or other similar corporate transaction involving all or substantially all of the common stock or other equity interests in, or assets of, Buyer, or (b) to any substitute purchaser of the Products so long as in the case of either clause (a) or clause (b) of this Section 14.4, either (1) the proposed assignee's credit rating is at least either BBB- from S&P or Baa3 from Moody's or (2) the proposed assignee's credit rating is equal to or better than that of Buyer at the time of the proposed assignment, or (3) such assignment, or in the case of clause (a) above the transaction associated with such assignment, has been approved by the MDPU.

14.5 Prohibited Assignments. Any purported assignment of this Agreement not in compliance with the provisions of this Section 14 shall be null and void.

15. TITLE; RISK OF LOSS

Title to and risk of loss related to Buyer's Percentage Entitlement of the Energy shall transfer from Seller to Buyer at the Delivery Point. Title and risk of loss related to Buyer's Percentage Entitlement of the RECs shall transfer to Buyer when the same are credited to

Buyer's GIS account(s) or the GIS account(s) designated by Buyer to Seller in writing. Seller warrants that it shall deliver to Buyer the Products free and clear of all claims therein or thereto by any Person.

16. AUDIT

16.1 Audit. Each Party shall have the right, upon reasonable advance notice, and at its sole expense (unless the other Party has defaulted under this Agreement, in which case the Defaulting Party shall bear the expense) and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, a Party shall provide to the other Party statements evidencing the quantities of Products delivered or provided hereunder. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof shall be made promptly and shall bear interest at the Late Payment Rate from the date the overpayment or underpayment was made until paid.

16.2 Consolidation of Financial Information. The Parties agree that generally accepted accounting principles and U.S. Securities and Exchange Commission rules require Buyer to evaluate whether Buyer must consolidate Seller's financial information on Buyer's financial statements. Buyer shall require access to financial records and personnel to determine if consolidated financial reporting is required. If Buyer determines at any time that such consolidation is required, Buyer shall require the following from Seller within fifteen (15) days after the end of every calendar quarter for the Term of this Agreement:

(a) complete financial statements and notes to financial statements for such quarter;

(b) financial schedules underlying such financial statements; and

(c) access to records and personnel to enable Buyer's independent auditor to conduct financial audits (in accordance with generally accepted auditing standards) and internal control audits (in accordance with Section 404 of the Sarbanes-Oxley Act of 2002). Any information provided to Buyer under this Section 16.2 shall be treated as confidential except that such information may be disclosed for financial statement purposes.

17. NOTICES

Any notice or communication given pursuant hereto shall be in writing and (1) delivered personally (personally delivered notices shall be deemed given upon written acknowledgment of receipt after delivery to the address specified or upon refusal of receipt); (2) mailed by registered or certified mail, postage prepaid (mailed notices shall be deemed given on the actual date of delivery, as set forth in the return receipt, or upon refusal of receipt); or (3) delivered by fax or electronic mail (notices sent by fax or electronic mail shall be deemed given upon confirmation of delivery); in each case addressed as follows or to such other addresses as may hereafter be designated by either Party to the other in writing:

If to Buyer: [ ]

With a copy to: [ ]

If to Seller: [ ]

With a copy to: [ ]

18. WAIVER AND MODIFICATION

This Agreement may be amended and its provisions and the effects thereof waived only by a writing executed by the Parties, and no subsequent conduct of any Party or course of dealings between the Parties shall effect or be deemed to effect any such amendment or waiver. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provision hereof (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided. The failure of either Party to enforce any provision of this Agreement shall not be construed as a waiver of or acquiescence in or to such provision. Buyer shall determine in its sole discretion whether any amendment or waiver of the provisions of this Agreement shall require MDPU approval or filing, and if Buyer determines that MDPU approval or filing is required for any amendment or waiver of the provisions of this Agreement, then such amendment or waiver shall not become effective unless and until such MDPU approval is obtained or such MDPU filing is made.

19. INTERPRETATION

19.1 <u>Choice of Law</u>. Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the Commonwealth of Massachusetts (without regard to its principles of conflicts of law).

19.2 <u>Headings</u>. Article and Section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and exhibits are, unless the context otherwise requires, references to articles, sections and exhibits of this Agreement. The words “hereof” and “hereunder” shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

19.3 <u>Forward Contract; Commodities Exchange Act</u>. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereunder are a “forward contract” within the meaning of the United States Bankruptcy Code. Each Party represents and warrants, solely as to itself, that it is (i) a “forward merchant” within the meaning of the United States Bankruptcy Code and (ii) an “eligible commercial entity” and an “eligible contract participant” within the meaning of the United States Commodities Exchange Act.

19.4 <u>Standard of Review</u>. The Parties acknowledge and agree that the standard of review for any avoidance, breach, rejection, termination or other cessation of performance of or changes to any portion of this integrated, non-severable Agreement (as described in Section 22) over which FERC has jurisdiction, whether proposed by Seller, by Buyer, by a non-party of, by FERC acting *sua sponte* shall be the “public interest” standard of review set forth in <u>United Gas</u>

Pipe Line Co. v. Mobile Gas Serv. Co., 350 U.S. 332 (1956) and Federal Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348 (1956). Each Party agrees that if it seeks to amend any applicable power sales tariff during the Term, such amendment shall not in any way materially and adversely affect this Agreement without the prior written consent of the other Party. Each Party further agrees that it shall not assert, or defend itself, on the basis that any applicable tariff is inconsistent with this Agreement.

19.5 Change in ISO-NE Rules and Practices. This Agreement is subject to the ISO-NE Rules and ISO-NE Practices. If, during the Term of this Agreement, any ISO-NE Rule or ISO-NE Practice is terminated, modified or amended or is otherwise no longer applicable, resulting in a material alteration of a material right or obligation of a Party hereunder, the Parties agree to negotiate in good faith in an attempt to amend or clarify this Agreement to embody the Parties' original intent regarding their respective rights and obligations under this Agreement, provided that neither Party shall have any obligation to agree to any particular amendment or clarification of this Agreement. The intent of the Parties is that any such amendment or clarification reflect, as closely as possible, the intent, substance and effect of the ISO-NE Rule or ISO-NE Practice being replaced, modified, amended or made inapplicable as such ISO-NE Rule or ISO-NE Practice was in effect prior to such termination, modification, amendment, or inapplicability, provided that such amendment or clarification shall not in any event alter (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

19.6 Change in Law or Buyer's Accounting Treatment. If, during the Term of this Agreement, there is a change in Law or accounting standards or rules or a change in the interpretation of applicability thereof that would result in adverse balance sheet or creditworthiness impacts on Buyer associated with this Agreement or the amounts paid for Products purchased hereunder, the Parties agree to negotiate in good faith in an attempt to amend or clarify this Agreement to avoid or significantly mitigate such impacts. Provided, however, neither Party shall have any obligation to agree to any particular amendment or clarification of this Agreement, and such amendment or clarification shall not in any event alter (i) the purchase and sale obligations of the Parties pursuant to this Agreement, or (ii) the Price or the Adjusted Price, as applicable.

20. COUNTERPARTS; FACSIMILE SIGNATURES

Any number of counterparts of this Agreement may be executed, and each shall have the same force and effect as an original. Facsimile signatures hereon or on any notice or other instrument delivered under this Agreement shall have the same force and effect as original signatures.

21. NO DUTY TO THIRD PARTIES

Except as provided in any consent to assignment of this Agreement, nothing in this Agreement nor any action taken hereunder shall be construed to create any duty, liability or standard of care to any Person not a Party to this Agreement.

22. SEVERABILITY

If any term or provision of this Agreement or the interpretation or application of any term or provision to any prior circumstance is held to be unenforceable, illegal or invalid by a court or agency of competent jurisdiction, the remainder of this Agreement and the interpretation or application of all other terms or provisions to Persons or circumstances other than those which are unenforceable, illegal or invalid shall not be affected thereby, and each term and provision shall be valid and be enforced to the fullest extent permitted by law.

23. INDEPENDENT CONTRACTOR

Nothing in this Agreement shall be construed as creating any relationship between Buyer and Seller other than that of Seller as independent contractor for the sale of Products, and Buyer as principal and purchaser of the same. Neither Party shall be deemed to be the agent of the other Party for any purpose by reason of this Agreement, and no partnership or joint venture or fiduciary relationship between the Parties is intended to be created hereby.

24. ENTIRE AGREEMENT

This Agreement shall constitute the entire agreement and understanding between the Parties hereto and shall supersede all prior agreements and communications.

[Signature page follows]

IN WITNESS WHEREOF, each of Buyer and Seller has caused this Agreement to be duly executed on its behalf as of the date first above written.

[Buyer]

By: ___________________________________
Name:
Title:

[Seller]

By: ___________________________________
Name:
Title:

EXHIBIT A

DESCRIPTION OF FACILITY

Facility: [Describe fully, including the location (street address and county or if there is none, longitude and latitude), the technology, fuel type, Operational Limitations, Delivery Point and criteria for substantial completion of the Facility as specified by Seller in its response to the RFP.]

EXHIBIT B

SELLER'S CRITICAL MILESTONES
PERMITS AND REAL ESTATE RIGHTS

Part 1 – Permits

a. Construction Permits
[to be completed]

b. Operating Permits
[to be completed]

Part 2 – Real Estate Rights
[to be completed]

EXHIBIT C

FORM OF PROGRESS REPORT

For the Quarter Ending:__________________

Status of construction and significant construction milestones achieved during the quarter:

Status of permitting and significant Permits obtained during the quarter:

Status of Financing for Facility:

Events during quarter expected to results in delays in Commercial Operation Date:

Critical Milestones not yet achieved and projected date for achievement:

Current projection for Commercial Operation Date:

EXHIBIT D

PRODUCTS AND PRICING

1. Price.

(a) The Price per MWH for the Products shall be equal to [$__] per MWh, commencing on the Commercial Operation Date. The Price per MWh for each billing period shall be allocated between Energy and RECs as follows:

[Formulation for NU and Unitil]

(i) Energy = [amount bid by Seller]

(ii) RECs = [amount bid by Seller]

[Formulation for National Grid]

(i) Energy = The $/MWh price of Energy for the applicable month shall be equal to the weighted average of the Locational Marginal Price in that month (also on a $/MWh basis) for the Node on the Pool Transmission Facilities to which the Facility is interconnected.

(ii) RECs = The Price less the Energy allocation determined above for the applicable billing period, expressed in $/MWh.

(b) The Adjusted Price for Energy shall be equal to [$__] per MWh.

(c) In the event that the LMP for the Energy at the Delivery Point is less than $0.00 per MWh in any hour, Seller shall credit or reimburse Buyer (at Buyer's discretion) the difference between $0 and such negative LMP per MWh for that Energy for each such hour. Each monthly invoice shall reflect a credit or reimbursement for all hours in the applicable month in which the LMP for the Energy at the Delivery Point is less than $0.00 per MWh.

Examples. If delivered Energy equals 1 MWh and Price equals $50.00/MWh:

LMP at the Delivery Point equals (or is greater than) $0.00/MWh
Buyer payment of Price to Seller = $50.00
Seller credit/reimbursement for negative LMP to Buyer = $0.00
Net Result: Buyer pays Seller $50 for that hour

LMP at the Delivery Point equals -$150.00/MWh
Buyer payment of Price to Seller = $50.00
Seller credit/reimbursement for negative LMP to Buyer = $150.00
Net Result: Seller credits or reimburses Buyer: $150 - $50 = $100 for that hour

2. Payment. Buyer shall, in accordance with the terms of the Agreement and this Exhibit D, with respect to any month after the Commercial Operation Date, pay to Seller, in immediately available funds, for each MWh of Products Delivered by Seller during such month, the Price per MWh or Adjusted Price per MWh set forth in Section 1 above, as applicable. .

REDACTED - PUBLIC VERSION

Line #	Company	Project Name	COD	Type	ST	Net MW	Avg. MWH Per Year	YR	Avg. Bid ¢/kwh	Level-ized Bid ¢/kwh	Price Points	Non-Price Points	Total Points
1	[redacted]												
2													
3													
4													
5													
6													
7													
8													
9													
10													
11													
12													
13													
14													
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35													
36													
37													
38													
39													
40													

					A. Siting and Permitting			B. Project Development Status and Operational Viability				C. Experience and Capability of Bidder and Project Team	D. Financing	E. Exceptions to PPA	
Line #	Current ID	Bid Entity	Project Name		A.1 Site Status	A.2 Permits	A.3 Community Relations	B.1 Critical Path Schedule/Commercial Operation Date Certainty	B.2 Fuel Supply/Energy Resource Plan	B.3 Commercial Access to and Reliability of the Proposed Technology	B.4 Interconnection Status	C1. Experience of Bidder	D1. Financing Plan	E1. Contract Exceptions	Total
				Max Points	[redacted]										
1	9	[redacted]			[redacted]										
2	30														
3	7														
4	10														
5	12														
6	8														
7	18														
8	1														
9	16														
10	32														
11	31														
12	37														
13	33														
14	40														
15	39														

REDACTED - PUBLIC VERSION

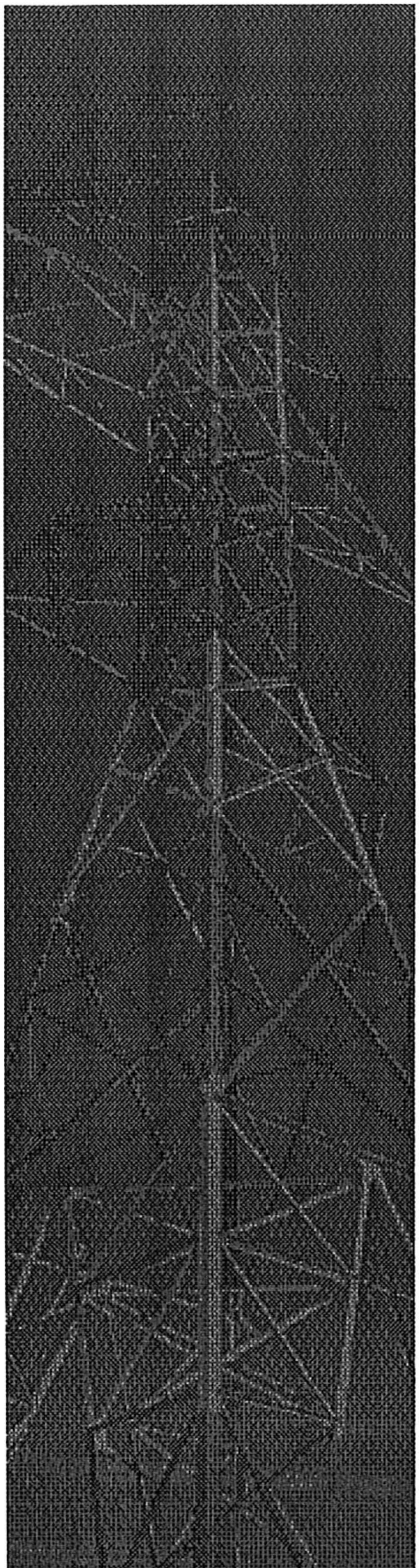
Line #	Company	Project Name	COD	ST	Net MW	Avg. MWH Per Year	YR	Avg. Bid ¢/kwh	Level-ized Bid ¢/kwh	Total Cost $M	Price Points	Non-Price Points	Total Points	Cum. Annual MWH	Target Req.
1	[redacted]														
2															
3															
4															
5															
6															
7															
8															
9															
10															
11															
12															
13															
14															
15															

Line #	Company	Project Name	COD	ST	Net MW	Avg. MWH Per Year	Ave. Rate ¢/kwh	Level-ized Bid ¢/kwh	Total Cost Nom $M	Price Points	Non-Price Points	Total Points	Target Req.
1	Exergy	Passamaquoddy	May-15	ME	38	[redacted]							
2	Iberdrola	Wild Meadows Wind	Dec-15	NH	74								
3	First Wind	Oakfield Wind	Dec-15	ME	148								
4	Exergy	Peskotmuhkati Wind Farm	Jul-14	ME	20								
5	First Wind	Bingham Wind	Dec-15	ME	186								
6	Iberdrola	Fletcher Mountain Wind	Dec-15	ME	99								
7	[redacted]												
8													
9													
10													
11													
12													
13													

[redacted]

Awarded

PUBLIC VERSION
REDACTED IN FULL



New England Energy & REC Outlook 2014-2038

A Study Prepared by
ESAI Power LLC
for
NStar Electric Company
National Grid
Western Massachusetts Electric Company
and Unitil Corporation

May 2013

ESAI
Power LLC

ESAI Power LLC
401 Edgewater Place, Suite 640, Wakefield, MA 01880
T: 781.245.2036 | F: 781.245.8706 | www.esai.com

WORKPAPERS

RFP Distribution List

Line #	Company Name	Last name	First Name	E-mail address
1	3Degrees		Darren	darren@3degreesinc.com
2	3Degrees	Favret	Leigh	lfavret@3degreesinc.com
3	3 Degrees	White	Omar	owhite@3degreesinc.com;
4	3 Phases Renewables	Hulin	Eric	ehulin@3phasesrenewables.com
5	3 Phases Renewables	Mazur	Mike	mmazur@3phasesRenewables.com
6	ABB	Vic	Lepage	vic.h.lepage@us.abb.com;
7	ABB	Rick	Ulam	rick.l.ulam@us.abb.com;
8	Acciona North America	Vickery	Chris	cvickery@acciona-na.com;
9	Achieve Renewable	Lessard	Larry	llessard@achieverenewable.com;
11	AL Advisors	McGee	JR	JRMcGee@aladvisors.net;
12	Aldi, Inc	McGee	Brian	brian.mcgee@aldi.us
13	Allco	Melone	Thomas	thomas.melone@allcous.com;
14	Alstom Power	Grina	Eric	eric.grina@power.alstom.com
15	Ameresco	Bakas	Michael	mbakas@ameresco.com;
16	Ameresco	Cohen	Shelley	scohen@ameresco.com;
17	Amerex Emissions, Ltd.	Schilling	John	john.schilling@amerexenergy.com
18	Amerex Energy	Sorkin	Elliot	esorkin@amerexenergy.com;
19	American Clean Energy	Ringel	George	george@amcleanenergy.com;
20	American Pro Wind	Jane	Rod	Neexpansion@aol.com
21	AQV Law	Vale	Quincy	Qvale@AQVLaw.com;
22	Arclight Capital	Chadbourne	Jonathan	jchadbourne@arclightcapital.com
24	Argus Media	Lamb	Celia	celia.lamb@argusmedia.com
25	Antrim Wind Energy LLC	Kenworthy	John B.	jkenworthy@eolian-energy.com
26	Attleboro Landfill	Long	William	wlong22@comcast.net;
28	Barclay's Capital	Dunton	Heather	heather.dunton@barcap.com;
29	BayCorp Holdings	Callendrello	Anthony	acallendrello@baycorpholdings.com;
30	Beacon Power	Lyons	Chet	lyons@beaconpower.com;
31	Beale Energy	Beale	Thomas	accordbeale@yahoo.com;
32	Beale Energy	Beale	Thomas	tbbeale@bealenergy.com;
33	Bella Energy	Strader	Hunter	hunter.strader@bellaenergy.com
34	BG Group	Black	David	david.black@bg-group.com;
35	Blackcomb Solar	Staiti	Mike	mikestaiti@keystonedev.net;
37	Borrego Solar	Chatterjee	Sam	schatterjee@borregosolar.com;
38	Bose	Bailey	Jack	jack_bailey@bose.com;
39	BP	Prescott	Randy	randy.prescott@bp.com;
40	Broadway Electric	Gallagher	John	jgallagher@broadelec.com
41	Broadway Electric	Hurwitz	Lawrence	lhurwitz@broadelec.com;
42	Broadway Electric	Wienslaw	Jonathan	jwienslaw@broadelec.com;
43	Broadway Electric	Wootan	Jeff	jwootan@broadelec.com;
44	Brookfield Energy Marketing	Couturier	Marcel	marcel.couturier@brookfieldpower.com;
45	Cape Wind	Olmsted	Craig	colmsted@capewind.org
46	Cape Wind Associates, LLC	Smith	Chris	csmith@emienergy.com
47	Capital Power	Ciullo	Daniel	dciullo@capitalpower.com
48	Capital Power	Kierstead	Michael	mkierstead@capitalpower.com;
49	Cargill	Alexander	Jay	Jay_Alexander@cargill.com;
50	Catalyst Renewables, LLC	Wiley	Colette	colettew@catalystrc.com
51	CCI Energy LLC	Sweeney	James	jim@ccienergy.com
52	Centerstone Partners	Fisher	Scott	sfisher@centerstonepartners.com;
53	Centerstone Partners	Prescott	Darrin	dprescott@centerstonepartners.com
54	Centerstone Partners	Roddy	Eric	eroddy@centerstonepartners.com
55	Central Vermont Public Service	Dunn	Dave	ddunn@cvps.com;
56	CEO Express	Boss	Peter	pbos@ceoexpress.com;
57	Citi	Clayton	Bob	Bo.clayton@citi.com;
58	Citi	Curry	Mike	mike.curry@citi.com;
59	Citi	Fleyhan	Ziad	ziad.fleyhan@citi.com;
60	Citi	Popovici	Roxana	roxana.popovici@citi.com;
61	Citizens Energy, Inc.	Male	Randy	rmale@citizensenergy.com
62	Clean Asset Partners	Denny-Brown	Doug	DDenny-Brown@CleanAssetPartners.com;
63	Clean Asset Partners	Kaufman	Steve	skaufman@cleanassetpartners.com;
65	Clear Energy Brokerage & Consulting LLC	Cook	Ryan	ryan.cook@clearenergybrokerage.com
66	Clear Energy Brokerage & Consulting LLC	Friskel	John	john.friskel@clearenergybrokerage.com
67	Clear Planet Energy	Pineda	Carlos	cpineda@clearplanetenergy.com;
68	Cocheco Falls	Straub	Gretchen	gstraub@gwi.net
69	Commonwealth Resource Management	Aronson	George	garonson@crmcx.com
70	Commonwealth Resource Management	Yeransian	Thomas	tyeransian@crmcx.com;

Line #	Company Name	Last name	First Name	E-mail address
71	Community Energy Inc.	Beerley	Brent	Brent.Beerley@communityenergyinc.com;
72	Community Energy Inc.	Sneed	Ian	ian.sneed@communityenergyinc.com;
73	Concord Power and Steam LLC	Bloomfield	Peter	peter@concordsteam.com
74	ConEd	Castellano	Anthony	castellanoa@conedenergy.com;
75	ConEd	Gilani	Rehan	gilanir@conedcss.com;
76	ConEd	Lai	Pamela	laip@conedenergy.com;
77	ConEd	Morgan	Sam	morgansa@conedsolutions.com;
78	ConEd	Sharif	Dipa	sharifd@coneddev.com;
79	ConEd	Sharif	Dipa	Sharifd@coneddev.com;
80	ConEd Solutions	Roskosky	Elise	RoskoskyE@conedsolutions.com;
81	Conservation Services Group	Barrett	Lisa	lisa.barrett@csgrp.com;
82	Conservation Services Group	Hamilton	Stephanie	Stephanie.hamilton@csgrp.com;
83	Conservation Services Group	Lange	Jennifer	jennifer.lange@csgrp.com;
84	Constellation	Bechta	Andrew	andrew.bechta@constellation.com;
85	Constellation	Marwaha	Rohit	Rohit.Marwaha@constellation.com;
86	Constellation	Ciccarone	Steve	Steve.Ciccarone@constellation.com;
87	Constellation	Ciccarone	Steve	Steve.Ciccarone@constellation.com;
88	Constellation	Johnson	Kyle	kyle.johnson@constellation.com;
89	Constellation	Chakraborty	Shuva	NENewEnglandStructuring@constellation.com;
90	Constellation	Rahm	Paul	paul.m.rahm@constellation.com;
91	Constellation	Nelson	Paul	paul.nelson@constellation.com;
92	Constellation	Rex	Jennifer	jennifer.rex@constellation.com;
93	Constellation	Rodocanachi	Stephen	Stephen.Rodocanachi@constellation.com;
94	Constellation	Sparks	Megan	megan.sparks@constellation.com;
96	Constellation	Heim	Dan	Dan.heim@constellation.com
97	Constellation ECG	Wangdi	Tsering	Tsering.Wangdi@constellation.com
98	CornerStone	Somers	Daniel	dsomers@CPDteam.com
99	Covanta	Kabbani	Sami	Skabbani@CovantaEnergy.com;
100	Covanta	Keyser	Eric	Ekeyser@CovantaEnergy.com;
101	Covanta	Nydam	Ken	knydam@covantaenergy.com;
102	CTC Electric	Tran	Tony	ttran@ctcelectric.com
103	CTC Electric	Roberts	John	jon@grenian.com
104	Deepwater Wind New England, LLC	Plummer	Clint	cplummer@dwwind.com
105	Deutsche Bank	Cox	Matt	matt.cox@db.com;
106	Deutsche Bank	Vinson	Donnie	donnie.vinson@db.com;
107	Direct Energy	Olsen	Dave	David.Olsen@directenergy.com;
108	Direct Energy	Segura	Stephanie	stephanie.segura@directenergy.com;
109	Direct Energy	Zager	David	david.zager@directenergy.com;
110	Direct Energy	Stewart	Ana	Ana.Stewart@directenergy.com
111	Dominion	Armstrong	Ron	ron.armstrong@dom.com;
112	Dominion	Howard	Murray	murray.howard@dom.com;
113	Dominion	Racelis	Joe	Joe_Racelis@dom.com;
114	DTE Energy	Alligood	Gary	alligoodg@dteenergy.com;
115	DTE Energy	Reicher	Erica	reichere@dteenergy.com;
116	DTE Energy	Schmelz	Rick	schmelzr@dteenergy.com;
117	DTE Energy	Wood	Joel	woodj@dteenergy.com;
118	Duke Energy	Wetzel	Mark	mawetzel@duke-energy.com;
119	E.ON AG	Franklin	John	john.franklin@eon.com;
121	Ecos Renewable	Nicholson	Blake	blake.nicholson@ecosrenewable.com
122	EDF Trading	Rich	Benjamin	Ben.Rich@edftrading.com;
123	EDP Renewables	Palmer	Mel	Mel.Palmer@edpr.com
124	EDP Renewables North America LLC	Steubing	Jacob	Jacob.Steubing@edpr.com
125	Edison Mission	Weiss	Paul	pweiss@edisonmission.com;
126	Element Markets	Matzen	Eric	ematzen@elementmarkets.com;
127	Element Markets	Nelson	Ken	knelson@elementmarkets.com;
128	Element Power	Glader	Anders	anders.glader@elpower.com
129	Elemental Power	Babcock	Robert	rbabcock@elemental-power.com
130	Elm Electrical	Rich	Kyle	krichard@elmelec.com;
131	Emera	Hutt	Karen	karen.hutt@emera.com;
132	Emera	McCullough	Andrew	Andrew.McCullogh@emeraenergy.com;
133	Emera	Munro	Patrick	patrick.munro@emeraenergy.com
134	Emera	O'Connor	Wayne	wayne.oconnor@emeraenergy.com;
135	Emergent Energy Group	Gossett	Jesse	jgossett@emergentgroup.com;
136	EMI	Duffy	Dennis	dduffy@emienergy.com
137	Encore Redevelopment	Mutty	Christopher	christopher@encoreredevelopment.com
138	Energy Acuity	Krebs	R. Paul	pkrebs@energyacuity.com

Line #	Company Name	Last name	First Name	E-mail address
139	Energy Consumers Alliance of NE	Wallenberg	Stephen	stephan@massenergy.org;
140	Energy New England	Coscia	Michelle	mcoscia@energynewengland.com;
141	Energy New England	Cunningham	Gary	gcunningham@energynewengland.com;
142	Energy New England	Hebert	Timothy	thebert@energynewengland.com
143	Energy New England	Myette	Gil	gmyette@energynewengland.com;
144	Energy ROI	Sullivan	William	bill@energyroi.net;
145	Energy Services Group	ESG		sales@energyservicesgroup.net;
146	Entergy	Potkin	Marc	mpotkin@entergy.com;
147	EnviroGen Marketing LLC	Kreppel	Robert J.	rkreppel@energypartnersusa.com
148	Environmental Markets	Mann	Dave	dave.mann@tradition.com;
149	Enxco	Peterson	Kristina	kristina.peterson@enxco.com
150	Eolian Renewable Energy LLC	Kenworthy	Jack	jkenworthy@eolian-energy.com
151	Eosol Energy	Abalo	Gus	gusabalo@avdg.us
152	EPICO USA, Inc.	Andreoli Bonazzi	Flavio	f.andreolibonazzi@epicoholding.it
153	Essex Hydro			dfa@essexhydro.com;
154	Essex Hydro Associates	Hickey	Stephen	sjh@essexhydro.com
155	Essex Hydro	Norman	Richard	ran@essexhydro.com;
156	Ethosde	Keenan	Joe	jkeenan@ethosde.com;
157	Evolution Markets LLC	Kolchins	Andrew	AKolchins@evomarkets.com
158	Evolution Markets	Zaborowsky	Peter	pzabo@evomarkets.com
159	First Wind	Birchby	Matt	mbirchby@firstwind.com;
160	First Wind	Chaytors	Ryan	rchaytors@firstwind.com;
162	First Wind	Khripko	Ilya	ikhripko@firstwind.com;
163	First Wind Energy	Kiely	Neil	nkiely@firstwind.com
164	First Wind Energy	Levin	Denys	DLevin@firstwind.com
165	First Wind	Wilby	David	dwilby@firstwind.com
166	First Wind	Zyla	Ivan	izyla@firstwind.com
167	Flett Exchange, LLC	Black	Ronald	rblack@flettexchange.com
168	Florida Power & Light	Boisvert	Larry	larry.boisvert@fpl.com;
169	Florida Power & Light	Camardese	David	David_V_Camardese@fpl.com;
170	Florida Power & Light			NEPOOL_LOAD@fpl.com;
171	Florida Power & Light	Tung	George	george_tung@fpl.com;
172	Florida Power & Light	Chiully	Peter	peter.chiulli@nexteraenergy.com;
173	Fole Hoag	Gentleman	Mary Beth	mgentleman@foleyhoag.com
174	Freepoint Commodities	Looram	Christopher	CLooram@freepoint.com;
175	Freepoint Commodities	Alptekin	Murat	MAlptekin@freepoint.com
176	FRS Development Services	Pineda	Carlos	cpineda@fr-sol.com
177	Gahagan & Associates	Gahagan	Hayes	hayes@gahaganllc.com;
178	Gas Recovery Systems	Passini	Massimo	mpassini@fortistar.com
179	GDF Suez	Adams	Steve	steve.adams@gdfsuezna.com;
180	Gentivity	Thompson	Bruce	brthompson@gentivity.com
181	GFI Group, Inc.	Alm	Erik	erik.alm@gfigroup.com
182	GFI Group	Woyshner	Greg	greg.woyshner@gfigroup.com;
183	Glacial Energy	Benson	Robert	robert.benson@glacialenergy.com;
185	GP Renewables & Trading		Adam	adam@gprenew.com;
186	GP Renewables & Trading		Alex	alex@gprenew.com;
187	GP Renewables & Trading	Phillips	Gabe	gabe@gprenew.com;
188	GP Renewables & Trading			rfp@gprenew.com;
189	Granby LFG	Gillis	Sandra	ips1@verizon.net;
191	Green Skies	Chester	Andrew	achester@greenskies.com;
192	GT Environmental Finance, LLC	Liggett	Will	will@gtenvfin.com
193	Harvard University	Chow	Joyceline	joyceline_chow@harvard.edu
194	Heartwood Group Inc	Unger	Fred	unger@hrtwd.com;
195	HelioSage	Foukal	Andrew	afoukal@heliosage.com;
196	HelioSage	Hantzmon	Matt	mhantzmon@heliosage.com;
197	HelioSage	Knetzger	Mike	mknetzger@heliosage.com
198	Hess	Chavan	Hambir	Hchavan@hess.com;
199	Hess	Little	Tyler	tlittle@hess.com
200	Hess	Miller	Tom	tsmiller@hess.com
201	Hess	Swenson	Nils	Nswenson@hess.com;
202	Highand Wind, LLC	Krich	Abigail	krich@boreasrenewables.com
203	Honeywell	McGrath	Bob	robert.mcgrath@honeywell.com;
204	Honeywell	Lucy	Jim	james.lucy@honeywell.com;
205	Hope Management			ziamk@hotmail.com;
206	Horizon Wind	Eckenrod	Erin	Erin.Eckenrod@horizonwind.com;
207	Horizon Wind	Irvin	Steve	Steve.Irvin@horizonwind.com;

Line #	Company Name	Last name	First Name	E-mail address
209	Hydro Quebec	Collins	Kyle	Collins.Kyle@hydro.qc.ca
210	Hydro Quebec	Levert	Hugo	Levert.Hugo@hydro.qc.ca;
211	Hydro Quebec	Tremblay	Mark	Tremblay.Mark@hydro.qc.ca
212	Iberdrola	Navitsky	Len	Leonard.Navitsky@iberdrolaren.com
213	ICAP Energy	Gibson	Tom	tom.gibson@us.icapenergy.com;
214	ICAP Energy	Sullivan	Brad	brad.sullivan@us.icapenergy.com;
215	ICAP United Inc.	Cecilia	Susan	Susan.Cecilia@us.icapenergy.com
216	ICAP United Inc.	Gibson	Thomas D.	tgibson@unitedpwr.com
217	IES	Koplas	David	dkoplas@ieslfge.com
218	Ignite Solar	Mahmud	Atif	amahmud@ignitesolar.com
219	IHS Emerging Energy	Klein	Alex	rfp@emerging-energy.com;
220	Independence Solar	Schwartz	James	jschwartz@independencesolar.com
221	Innovative Energy Solutions	Henningham	Scott	shenningham@ieslfge.com;
222	Innovative/DANC, LLC	Zeliff	Peter	pzeliff@ieslfge.com
223	Inspirra Energy	Gebhard	Thomas	tgebhard@inspirra.com
224	Interpower LLC	Barba	Doug	interpowerllc@aol.com;
227	Island Alliance	Powers	Tim	tpowers@islandalliance.org;
228	Jay Cashman Inc.	Kelley	Mike	mkelly@jaycashman.com;
229	Jimmy Peak Wind QF	Van Dyke	James	jvandyke@jiminy.com;
230	Jonesport wind Power, LLC	Nadeau	Kirk	knadeau@keanenergy.com
231	J. P. Morgan	Kelly	Brendan J	brendan.j.kelly@jpmorgan.com
232	JP Morgan	Samuels	David	david.a.samuels@jpmorgan.com;
233	K Road Power	Magaziner	Jonathan	jonathanm@kroadpower.com
234	Karbone Inc	Pouhe	Jacques	jacques.pouhe@karbone.com
235	Karbone Inc	Raphaely	Adam C.	adam.raphaely@karbone.com
236	Kean Energy	Whitney	Peter	pwhitney@keanenergy.com;
237	Keegan Werlin	Habib	Jack	jhabib@keeganwerlin.com;
238	Knollwood Energy	Lakritz	Alane	Alane@KnollwoodEnergy.com;
239	Laidlaw Energy	Bravikis	Lou	LTB@laidlawenergy.com;
240	Laidlaw Ware Biopower, LLC	Bravakis	Louis T.	LTB@laidlawenergy.com
241	Landcraft Corporation		George	gls02540@aol.com;
242	LB Energy Partners	Lukes	Tim	timothy.lukes@lbenergypartners.com;
243	LB Energy Partners	Lopez	Joseph	jlopez@equityone.net
244	LB Energy Partners	Peternell	Mark	MarkPeternell@regencycenters.com
245	LCM Commodities	Paftinos	Paul	ppaftinos@lcmcommodities.com;
246	LEE Energy Group	Bard	Todd	toddbard@yahoo.com;
247	Long Bay Management	Guscott	Ken	kguscott@longbaymgt.com;
248	Loranger Power Generation Corp	Brooks	David	brooks7818@aol.com;
249	Lorusso Corp/Plainville Generating	Grilli	Henry	henry.grilli@lorussocorp.com;
250	LS Power	Gorberg	Joe	Jgorberg@LSPower.com;
251	MMWEC	Smith	Stephen	ssmith@mmwec.org
252	Macquarie	Wilson	Mark	MVWilson@Macquarie.com
253	Macquarie	Konicki	Roberta	Roberta.Konicki@macquarie.com;
254	Macquarie	LaFrance	Bryan	Bryan.LaFrance@macquarie.com;
255	Macquarie	Merchant	Rafia	Rafia.Merchant@macquarie.com;
256	Macquarie	Mupparapu	Prashant	Prashant.Mupparapu@macquarie.com;
257	Mass Energu	Wollenburg	Stephan	Stephan@massenergy.org;
258	Minuteman Wind	McCauley	Don	don@minutemanwind.com;
259	ML Strategies	O'Connor	David	doconnor@mlstrategies.com
260	MWRA	Heidell	Pamela	pamela.heidell@mwra.state.ma.us;
261	National Grid	Meyer	Christopher	christopher.meyer@us.ngrid.com;
262	National Grid	Ruebenacker	James	james.ruebenacker@us.ngrid.com;
263	Natural Energy Generation	Marchand	Denis	dmarch1008@gmail.com
264	NEO Energy LLC	Callendrello	Anthony	acallendrello@baycorpholdings.com
265	NEO Energy, LLC.	Nicholson	Robert	rnicholson@neoenergyusa.com
266	NatSource	Intrator	Mike	mintrator@natsource.com
267	New England Clean Energy Council	Besser	Janet	jbesser@cleanenergycouncil.org
268	New England Clean Energy Council	Rothstein	Peter	prothstein@necec.org
269	New England Energy and Commerce Assn	Lawson	Lois	lois@necanews.org
270	New England Expansion Strategies	Jane	Rod	rodjane@neexpansion.com;
271	New England Power Generators Assn	Dolan	Daniel	ddolan@nepga.org
272	Nexamp	Kosciak	Emma	ekosciak@nexamp.com;
273	Nexant	Bedford	Kevin	kbedford@nexant.com;
274	Nexant Clean Energy Solutions	Flynn	Thomas J.	tflynn@nexant.com
275	Nexant	MacGregor	Paul	pmacgregor@nexant.com;
276	Nexant	Riley	Erin	eriley@nexant.com;

Line #	Company Name	Last name	First Name	E-mail address
277	NextEra Energy Resources	Camp	Adam	Adam.Camp@nexteraenergy.com
278	NextEra	Coleman	Melissa	melissa.coleman@nexteraenergy.com
279	NextEra Energy Canada, ULC	Geneau	Nicole	nicole.geneau@nexteraenergy.com
280	NextEra	Kujawa	Christopher	christopher.kujawa@nexteraenergy.com
281	NextEra	McLaughlin	Kevin	Kevin.McLaughlin@nexteraenergy.com;
283	NextEra	Tung	George	George.Tung@nexteraenergy.com
284	NextEra	Wang	Jessica	Jessica.Wang@nexteraenergy.com;
285	NextSun Energy	Laskin	Jacob	jake@nextsunenergy.com;
286	No Fossil Fuel	O'Donnell	Mary	mary@nofossilfuel.com
287	Noble Environmental Power	Rogers	David	RogersD@NOBLEPOWER.COM
288	Northeast Utilities	Bradway	Christie	bradwcl@nu.com;
289	Northeast Utilities	Olson	Robert	olsonrm@nu.com;
290	Northeast Utilities	Smith	Pat	smithpp@nu.com;
291	Notheast Wind	Zimmerman	John	johnz@northeastwind.com
292	Npower Corp		Nick	nick@npowercorp.com;
293	NRG Energy	Sawyer	Alan	alan.sawyer@nrgenergy.com;
294	NTE	Eves	Timothy	teves@nteenergy.com
295	NUGen Capital	Mclaren	Bob	rmclaren@nugencapital.com;
296	NUGen Capital	Milner	David	dmilner@nugencapital.com;
297	NYSEG	Converse	Jeff	jmconverse@nyseg.com;
298	NYSEG	Tigue	John	jrtigue@nyseg.com;
299	Oak Leaf Partners	McCabe	Mike	mike@oakleafep.com;
300	Orbit Energy Inc.	Shareef	Anwar	ashareef@orbitenergyinc.com
301	Orion Energy Systems			aibisevic@oriones.com;
302	Palmer Capital	Deane	Gordon	gdeane@palmcap.com
303	Patriot Renewables, LLC	Kelly	Michael	mkelly@patriotrenewables.com
304	Pattern Energy	McCune	Christopher	christopher.mccune@patternenergy.com
305	Pattern Energy	Metcalf	Kellie	kellie.metcalf@patternenergy.com
306	Patriot Renewables			info@patriotrenewables.com;
307	Patriot Renewables	Goldberg	Andrew	agoldberg@patriotrenewables.com
308	Patriot Renewables	Kelly	Michael	mkelly@patriotrenewables.com
309	Patriot Renewables	Presson	Todd	presson@gmavt.net
310	Penn Energy		Chris	chris@pennenergytrust.com;
311	Pepperell Hydro Co., LLC	Clark	Peter B.	pclark@swiftrivercompany.com
312	Pioneer Green Energy, LLC	Thompson	Bruce	bruce.thompson@pioneergreen.com
313	Pioneer Hydroelectric	Wright	Lucus	wareriverpower@aol.com
314	Platt's	Ciampoli	Paul	paul_ciampoli@platts.com;
315	Platt's	Craig	Geoffrey	Geoffrey_craig@platts.com;
316	Platt's			electric@platts.com;
317	Pope Energy	Pope	Doug	doug.pope@popeenergy.com;
318	Portsmouth Abbey	Ellen	Eggerman	eeggeman@portsmouthabbey.org
319	PPL	Babp	Alan	aababp@pplweb.com;
320	PPL	Fiore	Anne	awfiore@pplweb.com;
321	PPL	Moor	Roland	ramoor@pplweb.com;
322	PPL	Polaha	Joe	jppolaha@pplweb.com;
323	PPL	Stallings	Eric	SEStallings@pplweb.com;
324	PPL	Swope	John	jpswope@pplweb.com;
325	Princeton Municipal	Allen	Brian	brianallen@pmld.com;
326	Princeton Municipal Light Department	Fitch	Jonathan	jfitch@pmld.com
327	PSEG	Chung	Taewoo	taewoo.chung@pseg.com;
328	PSEG	Sutphen	Janice	janice.sutphen@pseg.com;
329	PSEG	Vinegra	Robert	robert.vinegra@pseg.com;
330	Putnam Hydro	Rosenfield	Charles	putnamhydro@charter.net;
331	Quantum Utility Generation	Swank	Tom	tswank@quantumug.com
332	RBC Dominion	Combs	Rene	Renee.Combs@rbccm.com;
333	Renewable Energy Development	Stricker	Peter	Peter.Stricker@nrgenergy.com
334	Renewable Energy Massachusetts LLC	Knowles	Bob	bknowles@remenergyco.com;
335	Renewable Energy Massachusetts LLC	Kopperl	Brian	bkopperl@remenergyco.com;
336	Renewable Energy New England	Pullaro	Francis	fpullaro@renew-ne.org
337	Revolution Energy, LLC	Behrmann	Mike	mike@rev-en.com
338	Rivermoor Energy	Tourtelotte	John	john@rivermoorenergy.com;
339	rTerra	Radeka	Mary Pat	mpradeka@rterra.com
340	Rumford Falls Hydro, LLC	Eckert	Steven E.	steve.eckert@brookfieldpower.com
341	Rural Aggregators of New England	Sax	Al	Al@ranesolar.com
342	Russell Biomass	Ramsey	James M.	jamesrams@verizon.net
343	Saywatt Hydroelectric, LLC	Zeleny	Rolland	indigoharbor@yahoo.com

Line #	Company Name	Last name	First Name	E-mail address
344	Senneca Falls Power Corp	Goodwin	Scott	scottgoodwin@hydroinsure.com;
345	Shell	Battersby	Robin	robin.battersby@shell.com;
346	Sigma Consulting	Fowler	William	wfowler@sigmaconsult.com;
347	Skystream Markets	Hofer	Christian	christian@skystreammarkets.com;
348	Skystream Markets	Mohindra	Kapil	kapil@skystreammarkets.com;
349	Skystream Markets	Nussbaum	David	dnussbaum@skystreammarkets.com;
350	Skystream Markets	Paul	Jason	jason@skystreammarkets.com;
351	SoCore Energy	Kadens	Pete	PKadens@socoreenergy.com;
352	Sol Systems	Horwitz	Yuri	yuri@solsystemscompany.com;
353	Sol Systems	Gollapudi	Sudha	sudha@solsystemscompany.com;
354	Sol Systems	Noucas	Anna	anna.noucas@solsystemscompany.com;
355	Sol Systems	Cauley	Christine	christine.cauley@solsystemscompany.com
356	Solar Power Partners, Inc	Hurley	Brian	bhurley@solarpowerpartners.com;
357	Solaya Energy LLC	Shah	Sumul	sumul@solayaenergy.com
358	Solterra	Plonsker	Steve	plonsker@solterrasolar.com;
359	Southern New Hampshire Hydroelectric	Webster	John	hydromagnt@yahoo.com
360	Southport Power, LLC	Selig	Gabriel	gselig@southportpower.com
361	Southcoast	Walton	Steve	SLW02136@yahoo.com
362	Southern Sky Renweable	Palumbo	Ralph	rpalumbo@southernskyrenewable.com;
363	Spectron Group			us.enviro@spectrongroup.com;
364	Spectron Energy, Inc.	Fergusen	Mike	enviro.us@spectrongroup.com
365	Spectron Energy	Restaino	Anthony	anthony.restaino@spectrongroup.com
366	Spectron Group	Velasquez	Jack	jack.Velasquez@spectrongroup.com;
367	SPG Solar	Connelly	Dylan	dylan.connelly@spgsolar.com;
368	SR Group			bbs@srgroup.org;
369	SREC Trading	Quilliam	Kevin	kevin.quilliam@srectrade.com;
370	Sterling Planet			rfp@sterlingplanet.com;
373	Suffolk University	Ferrey	Steve	sferrey@suffolk.edu;
374	Sun Edison	Lantz	Brian	blantz@sunedison.com
375	Sun Power Corp	Rein	Alex	Alex.Rein@sunpowercorp.com;
376	Sunbeam energy	Goldstein	Gregg	gregggoldstein@sunbeamenergy.net;
377	Sunbeam energy	Mahabir	Kris	krismahabir@sunbeamenergy.net;
378	Sustainable Energy Advantage	Gifford	Jason	jgifford@seadvantage.com;
379	Sustainable Energy Advantage	Grace	Bob	bgrace@seadvantage.com
380	Swift River Company	Whalley	Beth	bwhalley@swiftrivercompany.com
381	Tecta America	Beiser	Ken	kbeiser@tectaamerica.com;
382	Tecta America	Riedo	Katie	kriedo@tectaamerica.com;
383	TFS Energy, LLC.	Pinchin	Benjamin D.	Bpinchin@tfsenergy.com
384	TFS Energy	Swaine	Trevor	tswaine@tfsenergy.com;
385	Tioga Energy	Newman	Jordan	jordan@tiogaenergy.com;
386	Toshiba	Kilmer	Erica	erica.kilmer@tic.toshiba.com;
387	Toshiba	Lonkevych	Mark	mark.lonkevych@tic.toshiba.com
388	Town of Falmouth	Harper	Heather	hharper@falmouthmass.us;
389	TransCanada	Bertovic	Jasmin	jasmin_bertovic@transcanada.com ;
390	TransCanada	Hachey	Mike	mike_hachey@transcanada.com;
391	TransCanada	Ormsbee	Stuart	stuart_ormsbee@transcanada.com;
392	TransCanada	Tarves	Morgan	morgan_tarves@transcanada.com;
393	The Trustees of Reservations	Younger	James	jyounger@ttor.org
394	Turning Mill Energy	Giles	Alan	agiles@turningmillenergy.com;
395	Twin Cities Power	Bill	Bryce	ce@twincitiespower.com; bbryce@townsquareenergy.
396	Twin Cities Power	Miller	Randal	rmiller@twincitiespower.com
397	United Solar Consultants	McPherson	John	johnmcpherson@unitedsolarconsultants.com;
398	Unknown	Beebe	Brian	beebebp@gmail.com
399	Unknown	Bravakis	Lou	novus@together.net;
400	Unknown	Short	Bill	w.shortiii@verizon.net;
401	Unknown	Wood	George	georgewood4@verizon.net;
402	Unknown	Luke	Arthur	anluke@comcast.net;
		Lussier	Robert	lussier_Robert@yahoo.com
403	Uriel Wind			tbelousov@urielwind.com;
404	US Energy Saver LLC	Aney	Russ	RussAney@Yahoo.com
405	Vanguard Energy Partners	Gaeta	Marcia	mgaeta@vanguardenergypartners.com;
406	Veolia Energy North America Holdings, Inc	Plitch	Larry	lplitch@veoliaenergyna.com
407	Vitol, Inc	Wadsworth	Joe	jxw@vitol.com;
409	Waste Management	Glenn	LaToya	lglenn@wm.com;
410	Wells Fargo	Cotton	Cameron	cameron.cotten@wellsfargo.com;
411	Wells Fargo	Ryan	Kevin	kevin.c.ryan@wellsfargo.com;

Line #	Company Name	Last name	First Name	E-mail address
412	West Cape Wind Energy Inc.	Byrd	Lynn	Lynn.Byrd@gdfsuezna.com
413	Weston Solutions	Lindsay	Joel	joel.lindsay@westonsolutions.com;
414	Wheelabrator	Quinn	Ty	tquinn1@WM.COM
415	Wheelabrator	Qureshi	Asma	aqureshi@wm.com;
416	Winter Moon Organic	Docter	Mike	mdocter@wintermoonorganic.com;
417	WM Renewable Energy, LLC	Unger	David	dunger@wm.com
418	World Energy	Dumas	Jon	jdumas@worldenergy.com;
419	World Energy	Perry	Sean	sperry@worldenergy.com;
420	BNP Paribas	Rech	Amanda	amanda.rech@us.bnpparibas.com
421	Unknown	Selgrade	Ed	eselgrade@verizon.net;
422	Green Lake Capital	Sponseller	Michael	msponseller@greenlakecapital.co
423	NTF-energy	khawam	Maurice	maurice.khawam@ntf-energy.com
424	Pioneer Green	Thompson	Bruce	bruce.thompson@pioneergreen.com
425	unknown	Wood	Tyler	tylerowood@gmail.com

Notice of Intent participants

Line #	Company name	Technology	Project name/location
1	EDP Renewables North America LLC	Wind	Aroostook, ME
2	Wagner Wind Energy I, LLC	Wind	Coos County, NH
3	Apex Wind Energy Holdings, LLC	Wind	Rhode Island
4	Apex Wind Energy Holdings, LLC	Wind	Maine
5	Iberdrola Renewables LLC	Wind	Roaring Brook Wind Energy Project
6	Iberdrola Renewables LLC	Wind	Maine East Wind Energy Project
7	Iberdrola Renewables LLC	Wind	Fletcher Wind Energy Project
8	Iberdrola Renewables LLC	Wind	Wild Meadows Wind Energy Project
9	Halcyon Tidal Power LLC	Ocean Tidal Energy	Pembroke, ME
10	Orbit Energy, Inc.	Anaerobic Digestion	Georgetown, MA
11	Orbit Energy, Inc.	Anaerobic Digestion	Leominster, MA
12	Orbit Energy, Inc.	Anaerobic Digestion	Agawam, MA
13	Patriot Renewables, LLC	Wind	Canton, ME
14	Cape Wind Associates, LLC	Offshore Wind Energy	Horseshoe Shoal, Nantucket Sound
15	Minuteman Wind LLC/EDP Renewables NorthAmerica LLC	Wind	Savoy, MA
16	Alder stream Renewables LLC	Wind	Western Maine
17	Greenskies Renewable Energy LLC	Wind	MA
18	EDP Renewables North America LLC/American Pro Wind LLC	Wind	Douglas, MA
19	EDP Renewables North America LLC	Wind	Franklin County, NY
20	EDP Renewables North America LLC	Wind	Groton, NH
21	Highland Wind LLC	Wind	Maine
22	Garnet Hill Wind Farm, LLC and Lightship Energy, LLC	Wind	Peru, MA
23	Future Generation Wind LLC	Wind	Buzzards Bay, MA
24	South Mountain Wind LLC	Wind	Delaware County, NY
25	Monticello Hills Wind LLC	Wind	Otsego County, NY
26	Dry Lots Wind LLC	Wind	Herkimer County, NY
27	Deepwater Wind New England, LLC	Offshore Wind Energy	MA and RI
28	SunEdison Utility Solutions, LLC	Solar	Sandwich, MA
29	Timbertop Wind I, LLC	Wind	Temple, NH
30	Blue Sky West LLC (Bingham Wind project) [First Wind]	Wind	Bingham Wind project
31	Evergreen Windpower II LLC (Oakfield Wind project) [First Wind]	Wind	Oakfield Wind project
32	Hancock Wind LLC (Hancock Wind project) [First Wind]	Wind	Hancock Wind project
33	Weaver Wind LLC (Weavr Wind project) [First Wind]	Wind	Weavr Wind project
34	West Brand Community Wind LLC (Chester Wind project) First Wind]	Wind	Chester Wind project
35	Somerset Wind LLC (Somerset Wind project) [First Wind]	Wind	Somerset Wind project
36	Coye Hill Wind I, LLC	Wind	Union, CT
37	Snow Hill Wind I, LLC	Wind	Ashford, CT
38	Hecate Energy	Wind	Granby, MA
39	Green Peak Solar, LLC	Solar	Middlebury, VT
40	NextEra Energy Resources LLC	Wind	Watkins glen, NY

NSTAR ELECTRIC COMPANY

Direct Testimony of Richard D. Chin

D.P.U. 13-148

Q. Please state your name and business address.

A. My name is Richard D. Chin. My business address is One NSTAR Way, Westwood, Massachusetts 02090.

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

A. I am Manager of Rates for the Massachusetts regulated operating companies of Northeast Utilities which includes NSTAR Electric ("the Company"). In this capacity, I am responsible for pricing and rate design activities for the Company, which provides service in the territories formerly served by Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), and Commonwealth Electric Company ("Commonwealth").

Q. Please describe your education and professional background.

A. I graduated from Yale University in 1994 with a Bachelor of Arts degree in History. Upon graduation, I worked for two years as a corporate legal assistant at the law firm of Fried, Frank, Harris, Shriver, & Jacobson. I subsequently enrolled in Columbia University's School of International and Public Affairs, completing a Master of Public Administration in May 1999. In July 1999, I took a position as a consultant with London Economics, LLC, an economic consulting firm specializing in energy and utilities. My primary responsibilities were to model energy markets across the US and Canada for both regulatory bodies and independent power producers. In

January 2005, I joined NSTAR Electric & Gas as a Senior Regulatory Policy and Rate Analyst. In September 2012, I was named to my current position.

Q. Please describe your present responsibilities.

A. As Manager of Rates, I am responsible for the preparation and design of rate schedules and the pricing of special contracts for NSTAR Electric, NSTAR Gas and Western Massachusetts Electric Company. In addition, I am responsible for ensuring that new rate designs and programs are properly implemented.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes, I have presented testimony before the Department of Public Utilities (the "Department") in the Company's last three NSTAR Green semiannual rate adjustment filings, D.P.U. 12-36, 12-99 and 13-76, and the NSTAR Green Program Redesign filing D.P.U. 13-80. I have also testified in formal hearings in D.P.U. 10-RAAF-07/10-RAAF-10 concerning the Company's Residential Assistance Adjustment Factor, D.P.U. 08-52 concerning retail access for competitive suppliers of renewable energy generation attributes, and most recently in D.P.U. 10-169/D.P.U. 11-94 concerning the Company's Net Metering Recovery Surcharge.

Q. What is the purpose of your testimony?

A. My testimony will describe and support the use of the Company's Long-Term Renewable Contract Adjustment Tariff (the "LTRCA Tariff"), M.D.P.U. No. 164A for cost recovery of the six long-term contracts with (i) Passamaquoddy Wind, LLC

("Passamaquoddy Wind"); (ii) Peskotmuhkati Wind, LLC ("Peskotmuhkati Wind"); (iii) Evergreen Wind Power II, LLC ("Oakfield Wind"); (iv) Blue Sky West, LLC ("Bingham Wind"); (v) Iberdrola Renewables, LLC ("Fletcher Mountain"), and; (vi) Iberdrola Renewables, LLC ("Wild Meadows"). The six contracts consist of renewable generation attributes in New England over the contract term of fifteen or twenty years associated with a total of approximately 565 megawatts ("MW") of on-shore wind renewable generation supply.

Q. Is the Company sponsoring other witnesses to support this filing?

A. The cost components of the LTRCA Tariff used in deriving the Long Term Renewable Contract Adjustment Factor ("LTRCAF") are based upon the testimony of NSTAR Electric's other witness in this proceeding, Jeffrey S. Waltman. Mr. Waltman, in his Joint Testimony, describes the six contracts that NSTAR Electric has executed to procure the renewable energy attributes that will be used to satisfy the requirements of the Green Communities Act (St. 2008, c. 169, § 83A) ("GCA").

Q. What exhibits are you sponsoring in your testimony?

A. In addition to my testimony, I am sponsoring Exhibit NSTAR-RDC-1 [**Confidential**] which sets forth the cost elements that would be used to develop the rate under the provisions of the LTRCA Tariff. I am also sponsoring Exhibits NSTAR-RDC-2, NSTAR-RDC-3, and NSTAR-RDC-4 which provide illustrative bill impacts. In addition, Exhibit NSTAR-RDC-5 is the revised LTRCA tariff reflecting the Section 83A amendment to the GCA which modified the contracting distribution company's annual remuneration from 4 percent to 2.75 percent for contracts entered into on or after January 1, 2013.

Q. Please describe the Tariff.

A. The LTRCA Tariff is a an approved rate schedule describing the availability, definition, pricing and term of service for the recovery from distribution customers of costs relating to long-term renewable contracts, pursuant to Sections 83 and 83A of the GCA and 220 C.M.R. 21.00, et seq..

Q. Please describe the costs eligible to be recovered by the LTRCA Tariff.

A. The LTRCA Tariff, approved by the Department in D.P.U. 12-30 (first approved in D.P.U. 11-05; D.P.U. 11-06; and D.P.U. 11-07) and the proposed revision allows the Company to recover the following costs associated with the Company's various long-term renewable contracts procured pursuant to Sections 83 and 83A: (1) the net costs of the energy sold into the ISO-New England Real Time Energy Market; (2) the net costs of capacity sold into the Forward Capacity Market; (3) the net costs of the Class I Renewable Energy Credits ("RECs") obtained under the long-term contracts and (4) the remuneration associated with procuring long-term contracts allowed by Sections 83 and 83A. The costs included in the determination of the LTRCAF for the recovery year will be estimated based upon the contract prices and the estimated deliveries under the contracts.

Q. Will the Company reconcile estimated costs to actual contract costs under the LTRCA tariff?

A. Yes, the LTRCA Tariff provides that each year the Company will compare the net of its actual costs associated with the Company's Department-approved renewable contracts, as described above, and the actual proceeds received from the wholesale electricity market (associated with the sale of energy procured by the contracts), during the year with the actual revenue collected from customers in the year through the LTRCAF. Any over- or under-collection that results will be included in the annual calculation of the LTRCAF applicable in the following year.

Q. Please explain how the LTRCAF will recover costs associated with the purchase and transfer of Energy and RECs associated with the six contracts.

A. The net cost of the Energy and RECs under the six contracts on an annual basis will be recovered from the Company's distribution customers as part of the annual LTRCAF. As described by Mr. Waltman, the Company will then charge basic service customers for any contract RECs retained and applied to satisfy the Company's RPS obligations related to basic service, not at the contract price but at the average REC prices obtained in the Company's periodic solicitations for RECs procured to meet its basic service RPS requirements. This average REC price represents the market value of the contract RECs and is included as a credit to the cost to be recovered by the LTRCAF. This is the same methodology for the recovery of REC costs that the Department reviewed and approved in D.P.U. 11-05; D.P.U. 11-06 and D.P.U. 11-07.

Q. Please describe Exhibit NSTAR-RDC-1.

A. Exhibit NSTAR-RDC-1 [**Confidential**] is an illustrative template for the inclusion of the six contracts in the LTRCAF. The total market value of the products obtained under the Company's six long-term contracts is subtracted from the total recoverable cost of these contracts. Any prior period reconciliation, either positive or negative, of the actual contract costs, proceeds and customer revenue would also be included in the calculation of the current period LTRCAF.

Q. When will the costs of the six contracts be incorporated into the LTRCAF?

A. As described in Mr. Waltman's testimony, the proposed commercial operation dates range from year end 2014 to year end 2016. Therefore, the first year all six contracts will be in operation collectively is 2017. Accordingly, the Company estimates that it will commence including the costs of the six contracts in its LTRCAF filing for approval on October 31, 2016, for effect January 1, 2017. It should be noted that the Company's final development of the LRTCAF for 2017 will include the Secton 83 renewable contracts approved by the Department in D.P.U. 11-05; D.P.U. 11-06; and D.P.U. 11-07 and will be submitted to the Department as part of the Company's annual distribution rate adjustment/reconciliation filing.

Q. Have you provided bill impacts related to the recovery of the contract costs associated with the six contracts?

A. Yes, bill impacts are presented in Exhibits NSTAR-RDC-2, NSTAR-RDC-3, and NSTAR-RDC-4. Since the Company is not proposing in this filing actual recovery through the LTRCAF of the costs of the six contracts, the included bill impacts are intended to provide only an illustration of how the contracts would impact customers based on the current market environment. Moreover, the net costs of the six contracts will be just one part of the development of the LTRCAF, which will also include the net costs of the Company's other long-term renewable energy contracts.

Q. Does this conclude your testimony?

A. Yes, it does.

REDACTED - PUBLIC VERSION

NSTAR Electric Company
2017 Long-Term Renewable Contract Adjustment Forecast
Illustrative
$ in Millions

Line #		A/C	Energy	RECs	Remuneration (A)	REC Transfer (B)	Market Monitoring	Total	Reference
1	Long-Term Renewable Contract Adjustment Costs								
2	Wild Meadows Project	555	$ [redacted]						
3	Fletcher Mountain Project	555							
4	Oakfield Wind Project	555							
5	Bingham Wind Project	555							
6	Passamaquoddy Wind Project	555							
7	Peskotmuhkati Wind Project	555							
8	Subtotal		$						Sum Lines 2 thru 7
9	Long-Term Renewable Contract Market Revenues								
10	Wild Meadows Project	447	$ [redacted]						
11	Fletcher Mountain Project	447							
12	Oakfield Wind Project	447							
13	Bingham Wind Project	447							
14	Passamaquoddy Wind Project	447							
15	Peskotmuhkati Wind Project	447							
16	Subtotal		$						Sum Lines 10 thru 15
17	Current Year activity (net)							$ (32.127)	Line 8 + Line 16
18	Prior Year (Over)/Under Collection							-	
19	Long-Term Renewable Contract Adjustment to be Collected							$ (32.127)	Line 17 + Line 18
20	Forecast 2017 Billed GWH							21,400.000	
21	2017 Long-Term Renewable Contract Adjustment Factor ($/kWh)							$ (0.00150)	Line 19 / Line 20

(A) Remuneration = (Energy Cost + REC Cost) * 2.75%
(B) RECs transferred to Basic Service for RPS requirements at market price for vintage Class I RECs

BOSTON EDISON
TYPICAL BILL COMPARISONS
AUGUST 2013 DELIVERY RATES

					Proposed vs. Current Change in Total Bill	
Class	Rate	Hrs Use	Avg Kw	Avg Kwh	Amount	%
Residential	Res Rate R-1			586	(0.76)	-0.75%
	Res Assist R-2 (R1)			449	(0.42)	-0.77%
	Res Space Htg R-3 (Winter)			1,071	(1.38)	-0.80%
	Res Space Htg R-3 (Summer)			689	(0.89)	-0.76%
	Res Assist R-2 (R3) Winter			1,072	(1.03)	-0.86%
	Res Assist R-2 (R3) Summer			537	(0.52)	-0.79%
	Res TOU R-4 Winter			1,020	(1.32)	-0.81%
	Res TOU R-4 Summer			1,429	(1.84)	-0.77%
Small Comm.	Genral G-1 w/o Demand - Winter			615	(0.80)	-0.75%
	Genral G-1 w/o Demand - Summer			595	(0.77)	-0.64%
	Genral G-1 w/ Demand - Winter	150	5	750	(0.97)	-0.80%
	Genral G-1 w/ Demand - Summer	150	5	750	(0.97)	-0.69%
	Genral G-1 w/ Demand - Winter	300	5	1,500	(1.93)	-0.83%
	Genral G-1 w/ Demand - Summer	300	5	1,500	(1.94)	-0.72%
	Genral G-2 - Winter	200	27	5,400	(6.97)	-0.82%
	Genral G-2 - Summer	200	29	5,800	(7.48)	-0.57%
	Genral G-2 - Winter	250	27	6,750	(8.71)	-0.88%
	Genral G-2 - Summer	250	29	7,250	(9.35)	-0.63%
	Genral G-2 - Winter	300	27	10,800	(13.93)	-1.00%
	Genral G-2 - Summer	300	29	11,600	(14.96)	-0.78%
	Genral TOU T-1 Winter			1,265	(1.63)	-0.75%
	Genral TOU T-1 Summer			969	(1.25)	-0.54%
Lg Comm/Ind	Genral G-3 - Winter NEMA	350	1,171	409,850	(528.71)	-0.93%
	Genral G-3 - Summer NEMA	350	1,373	480,550	(619.91)	-0.83%
	Genral G-3 - Winter NEMA	450	1,171	526,950	(679.76)	-1.02%
	Genral G-3 - Summer NEMA	450	1,373	617,850	(797.03)	-0.93%
	Genral G-3 - Winter NEMA	500	1,171	585,500	(755.30)	-1.06%
	Genral G-3 - Summer NEMA	500	1,373	686,500	(885.59)	-0.97%
	Genral TOU T-2 - Winter NEMA	350	316	110,600	(142.67)	-0.90%
	Genral TOU T-2 - Summer NEMA	350	337	117,950	(152.16)	-0.77%
	Genral TOU T-2 - Winter NEMA	400	316	126,400	(163.06)	-0.94%
	Genral TOU T-2 - Summer NEMA	400	337	134,800	(173.89)	-0.82%
	Genral TOU T-2 - Winter NEMA	450	316	142,200	(183.44)	-0.99%
	Genral TOU T-2 - Summer NEMA	450	337	151,650	(195.63)	-0.86%
	Genral G-3 - Winter SEMA	350	823	288,050	(371.59)	-0.95%
	Genral G-3 - Summer SEMA	350	914	319,900	(412.67)	-0.84%
	Genral G-3 - Winter SEMA	450	823	370,350	(477.76)	-1.04%
	Genral G-3 - Summer SEMA	450	914	411,300	(530.58)	-0.94%
	Genral G-3 - Winter SEMA	500	823	411,500	(530.84)	-1.08%
	Genral G-3 - Summer SEMA	500	914	457,000	(589.53)	-0.98%
	Genral TOU T-2 - Winter SEMA	350	238	83,300	(107.46)	-0.91%
	Genral TOU T-2 - Summer SEMA	350	262	91,700	(118.29)	-0.78%
	Genral TOU T-2 - Winter SEMA	400	238	95,200	(122.81)	-0.96%
	Genral TOU T-2 - Summer SEMA	400	262	104,800	(135.19)	-0.83%
	Genral TOU T-2 - Winter SEMA	450	238	107,100	(138.16)	-1.00%
	Genral TOU T-2 - Summer SEMA	450	262	117,900	(152.09)	-0.87%

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL RATE R-1

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		148	$30.47	$11.14	$19.33	$30.28	$11.14	$19.14	($0.19)	-0.6%
20		206	$39.79	$15.46	$24.33	$39.52	$15.46	$24.06	($0.27)	-0.7%
30		268	$49.84	$20.12	$29.72	$49.50	$20.12	$29.38	($0.34)	-0.7%
40		333	$60.44	$25.03	$35.41	$60.01	$25.03	$34.98	($0.43)	-0.7%
50		408	$72.47	$30.60	$41.87	$71.94	$30.60	$41.34	($0.53)	-0.7%
60		497	$86.92	$37.30	$49.62	$86.28	$37.30	$48.98	($0.64)	-0.7%
70		610	$105.16	$45.75	$59.41	$104.38	$45.75	$58.63	($0.78)	-0.7%
80		762	$129.89	$57.21	$72.68	$128.91	$57.21	$71.70	($0.98)	-0.8%
90		1,008	$169.68	$75.65	$94.03	$168.38	$75.65	$92.73	($1.30)	-0.8%
AVG.USE		586	$101.36	$43.99	$57.37	$100.60	$43.99	$56.61	($0.76)	-0.7%

Current

RESIDENTIAL RATE R-1

DELIVERY SERVICES:

CUSTOMER		$6.43	PER BILL
DISTRIBUTION	ALL KWH @	4.598	CENTS/KWH
TRANSITION	" "	0.783	" "
TRANSMISSION	" "	1.762	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
TRANSITION RATE ADJ	" "	0.000	" "
DEFAULT SERV ADJ	" "	0.000	" "
DIST ADJ	" "	1.249	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	

Proposed

RESIDENTIAL RATE R-1

DELIVERY SERVICES:

CUSTOMER		$6.43	PER BILL
DISTRIBUTION	ALL KWH @	4.598	CENTS/KWH
TRANSITION	" "	0.783	" "
TRANSMISSION	" "	1.762	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
TRANSITION RATE ADJ	" "	0.000	" "
DEFAULT SERV ADJ	" "	0.000	" "
DIST ADJ	" "	1.120	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL ASSISTANCE RATE R-2 (W/O SPACE HEATING) (R1)

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		143	$20.69	$7.85	$12.84	$20.55	$7.85	$12.70	($0.14)	-0.7%
20		188	$25.73	$10.32	$15.41	$25.55	$10.32	$15.23	($0.18)	-0.7%
30		234	$30.86	$12.84	$18.02	$30.64	$12.84	$17.80	($0.22)	-0.7%
40		282	$36.18	$15.45	$20.73	$35.92	$15.45	$20.47	($0.26)	-0.7%
50		333	$41.89	$18.25	$23.64	$41.57	$18.25	$23.32	($0.32)	-0.8%
60		392	$48.47	$21.48	$26.99	$48.10	$21.48	$26.62	($0.37)	-0.8%
70		463	$56.44	$25.39	$31.05	$56.01	$25.39	$30.62	($0.43)	-0.8%
80		559	$67.15	$30.65	$36.50	$66.63	$30.65	$35.98	($0.52)	-0.8%
90		717	$84.77	$39.29	$45.48	$84.10	$39.29	$44.81	($0.67)	-0.8%
AVG.USE		449	$54.85	$24.61	$30.24	$54.43	$24.61	$29.82	($0.42)	-0.8%

Current

RESIDENTIAL ASSISTANCE RATE R-2 (W/O SPACE HEATING)

DELIVERY SERVICES:

CUSTOMER		$6.43	PER BILL
DISTRIBUTION	ALL KWH @	4.598	CENTS/KWH
TRANSITION	" "	0.783	" "
TRANSMISSION	" "	1.762	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
TRANSITION RATE ADJ	" "	-0.001	" "
DEFAULT SERV ADJ	" "	0.000	" "
DIST ADJ	" "	0.349	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	

LOW INCOME DISCOUNT 27.0%

Proposed

RESIDENTIAL ASSISTANCE RATE R-2 (W/O SPACE HEATING)

DELIVERY SERVICES:

CUSTOMER		$6.43	PER BILL
DISTRIBUTION	ALL KWH @	4.598	CENTS/KWH
TRANSITION	" "	0.783	" "
TRANSMISSION	" "	1.762	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
TRANSITION RATE ADJ	" "	-0.001	" "
DEFAULT SERV ADJ	" "	0.000	" "
DIST ADJ		0.220	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	

LOW INCOME DISCOUNT 27.0%

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SPACE HEATING RATE R-3

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	WINTER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		297	$52.21	$22.29	$29.92	$51.82	$22.29	$29.53	($0.39)	-0.7%
20		417	$70.71	$31.30	$39.41	$70.17	$31.30	$38.87	($0.54)	-0.8%
30		536	$89.05	$40.23	$48.82	$88.36	$40.23	$48.13	($0.69)	-0.8%
40		654	$107.24	$49.09	$58.15	$106.39	$49.09	$57.30	($0.85)	-0.8%
50		779	$126.50	$58.47	$68.03	$125.50	$58.47	$67.03	($1.00)	-0.8%
60		932	$150.09	$69.96	$80.13	$148.89	$69.96	$78.93	($1.20)	-0.8%
70		1,115	$178.29	$83.69	$94.60	$176.86	$83.69	$93.17	($1.43)	-0.8%
80		1,370	$217.60	$102.83	$114.77	$215.83	$102.83	$113.00	($1.77)	-0.8%
90		1,841	$290.21	$138.19	$152.02	$287.83	$138.19	$149.64	($2.38)	-0.8%
AVG.USE		1,071	$171.51	$80.39	$91.12	$170.13	$80.39	$89.74	($1.38)	-0.8%

Current

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.249	1.249	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.120	1.120	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SPACE HEATING RATE R-3

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		219	$41.85	$16.44	$25.41	$41.57	$16.44	$25.13	($0.28)	-0.7%
20		285	$52.52	$21.39	$31.13	$52.15	$21.39	$30.76	($0.37)	-0.7%
30		355	$63.85	$26.65	$37.20	$63.39	$26.65	$36.74	($0.46)	-0.7%
40		422	$74.68	$31.68	$43.00	$74.14	$31.68	$42.46	($0.54)	-0.7%
50		488	$85.35	$36.63	$48.72	$84.73	$36.63	$48.10	($0.62)	-0.7%
60		568	$98.29	$42.63	$55.66	$97.56	$42.63	$54.93	($0.73)	-0.7%
70		677	$115.93	$50.82	$65.11	$115.05	$50.82	$64.23	($0.88)	-0.8%
80		831	$140.82	$62.37	$78.45	$139.75	$62.37	$77.38	($1.07)	-0.8%
90		1,041	$174.79	$78.14	$96.65	$173.45	$78.14	$95.31	($1.34)	-0.8%
AVG.USE		689	$117.87	$51.72	$66.15	$116.98	$51.72	$65.26	($0.89)	-0.8%

Current

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.249	1.249	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.120	1.120	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RES ASSISTANCE RATE R-2 (with SPACE HEATING) (R3)

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	WINTER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		284	$35.41	$15.84	$19.57	$35.13	$15.84	$19.29	($0.28)	-0.8%
20		423	$50.39	$23.59	$26.80	$49.99	$23.59	$26.40	($0.40)	-0.8%
30		559	$65.06	$31.18	$33.88	$64.53	$31.18	$33.35	($0.53)	-0.8%
40		682	$78.32	$38.03	$40.29	$77.67	$38.03	$39.64	($0.65)	-0.8%
50		812	$92.34	$45.28	$47.06	$91.56	$45.28	$46.28	($0.78)	-0.8%
60		962	$108.52	$53.65	$54.87	$107.60	$53.65	$53.95	($0.92)	-0.8%
70		1,144	$128.14	$63.80	$64.34	$127.05	$63.80	$63.25	($1.09)	-0.9%
80		1,429	$158.87	$79.69	$79.18	$157.51	$79.69	$77.82	($1.36)	-0.9%
90		1,832	$202.34	$102.17	$100.17	$200.58	$102.17	$98.41	($1.76)	-0.9%
AVG.USE		1,072	$120.38	$59.78	$60.60	$119.35	$59.78	$59.57	($1.03)	-0.9%

Current

RES ASSISTANCE RATE R-2 WITH SPACE HEATING

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.349	0.349	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	
LOW INCOME DISCOUNT	25.7%	25.7%	

Proposed

RES ASSISTANCE RATE R-2 WITH SPACE HEATING

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.220	0.220	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "
LOW INCOME DISCOUNT	25.7%	25.7%	

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RES ASSISTANCE RATE R-2 (with SPACE HEATING)(R3)

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		222	$29.97	$12.38	$17.59	$29.76	$12.38	$17.38	($0.21)	-0.7%
20		257	$33.94	$14.33	$19.61	$33.69	$14.33	$19.36	($0.25)	-0.7%
30		325	$41.66	$18.13	$23.53	$41.35	$18.13	$23.22	($0.31)	-0.7%
40		369	$46.65	$20.58	$26.07	$46.30	$20.58	$25.72	($0.35)	-0.8%
50		440	$54.71	$24.54	$30.17	$54.29	$24.54	$29.75	($0.42)	-0.8%
60		516	$63.34	$28.78	$34.56	$62.84	$28.78	$34.06	($0.50)	-0.8%
70		598	$72.64	$33.35	$39.29	$72.06	$33.35	$38.71	($0.58)	-0.8%
80		661	$79.78	$36.86	$42.92	$79.15	$36.86	$42.29	($0.63)	-0.8%
90		827	$98.62	$46.12	$52.50	$97.83	$46.12	$51.71	($0.79)	-0.8%
AVG.USE		537	$65.72	$29.95	$35.77	$65.20	$29.95	$35.25	($0.52)	-0.8%

Current

RES ASSISTANCE RATE R-2 WITH SPACE HEATING

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.349	0.349	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	
LOW INCOME DISCOUNT	25.7%	25.7%	

Proposed

RES ASSISTANCE RATE R-2 WITH SPACE HEATING

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$6.43	PER BILL
DISTRIBUTION	4.596	3.837	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	1.739	1.739	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.220	0.220	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "
LOW INCOME DISCOUNT	25.7%	25.7%	

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL TOU RATE R-4

			Current			**Proposed**			**DIFFERENCE**	
CUM % BILLS	KW	WINTER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		217	$42.42	$16.29	$26.13	$42.14	$16.29	$25.85	($0.28)	-0.7%
20		407	$70.80	$30.55	$40.25	$70.28	$30.55	$39.73	($0.52)	-0.7%
30		519	$87.54	$38.96	$48.58	$86.87	$38.96	$47.91	($0.67)	-0.8%
40		635	$104.87	$47.66	$57.21	$104.05	$47.66	$56.39	($0.82)	-0.8%
50		766	$124.45	$57.50	$66.95	$123.46	$57.50	$65.96	($0.99)	-0.8%
60		918	$147.16	$68.91	$78.25	$145.98	$68.91	$77.07	($1.18)	-0.8%
70		1,050	$166.88	$78.81	$88.07	$165.52	$78.81	$86.71	($1.36)	-0.8%
80		1,347	$211.26	$101.11	$110.15	$209.53	$101.11	$108.42	($1.73)	-0.8%
90		2,095	$323.03	$157.25	$165.78	$320.32	$157.25	$163.07	($2.71)	-0.8%
AVG.USE		1,020	$162.40	$76.56	$85.84	$161.08	$76.56	$84.52	($1.32)	-0.8%

Current

RESIDENTIAL TOU RATE R-4

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$9.99	PER BILL
DISTRIBUTION Peak	10.966	5.569	CENTS/KWH
TRANSITION Peak	0.783	0.783	" "
TRANSMISSION Peak	7.264	5.500	" "
DISTRIBUTION Off Pk	2.333	2.230	" "
TRANSITION Off Pk	0.877	0.877	" "
TRANSMISSION Off Pk	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	CENTS/KWH
RENEWABLE ENERGY	0.050	0.050	" "
TRANSIT RATE ADJ PEAK	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.249	1.249	" "

SUPPLIER SERVICES:

	Summer	Winter	
DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

RESIDENTIAL TOU RATE R-4

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$9.99	PER BILL
DISTRIBUTION Peak	10.966	5.569	CENTS/KWH
TRANSITION Peak	0.783	0.783	" "
TRANSMISSION Peak	7.264	5.500	" "
DISTRIBUTION Off Pk	2.333	2.230	" "
TRANSITION Off Pk	0.877	0.877	" "
TRANSMISSION Off Pk	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	CENTS/KWH
RENEWABLE ENERGY	0.050	0.050	" "
TRANSIT RATE ADJ PEAK	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.120	1.120	" "

SUPPLIER SERVICES:

	Summer	Winter	
DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL TOU RATE R-4

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		232	$47.27	$17.41	$29.86	$46.97	$17.41	$29.56	($0.30)	-0.6%
20		392	$72.98	$29.42	$43.56	$72.48	$29.42	$43.06	($0.50)	-0.7%
30		564	$100.62	$42.33	$58.29	$99.89	$42.33	$57.56	($0.73)	-0.7%
40		717	$125.21	$53.82	$71.39	$124.29	$53.82	$70.47	($0.92)	-0.7%
50		828	$143.05	$62.15	$80.90	$141.98	$62.15	$79.83	($1.07)	-0.7%
60		983	$167.96	$73.78	$94.18	$166.69	$73.78	$92.91	($1.27)	-0.8%
70		1,183	$200.10	$88.80	$111.30	$198.58	$88.80	$109.78	($1.52)	-0.8%
80		1,382	$232.08	$103.73	$128.35	$230.29	$103.73	$126.56	($1.79)	-0.8%
90		1,951	$323.52	$146.44	$177.08	$321.00	$146.44	$174.56	($2.52)	-0.8%
AVG.USE		1,429	$239.63	$107.26	$132.37	$237.79	$107.26	$130.53	($1.84)	-0.8%

Current

RESIDENTIAL TOU RATE R-4

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$9.99	PER BILL
DISTRIBUTION Peak	10.966	5.569	CENTS/KWH
TRANSITION Peak	0.783	0.783	" "
TRANSMISSION Peak	7.264	5.500	" "
DISTRIBUTION Off Pk	2.333	2.230	" "
TRANSITION Off Pk	0.877	0.877	" "
TRANSMISSION Off Pk	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	CENTS/KWH
RENEWABLE ENERGY	0.050	0.050	" "
TRANSIT RATE ADJ PEAK	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.249	1.249	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

RESIDENTIAL TOU RATE R-4

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$9.99	PER BILL
DISTRIBUTION Peak	10.966	5.569	CENTS/KWH
TRANSITION Peak	0.783	0.783	" "
TRANSMISSION Peak	7.264	5.500	" "
DISTRIBUTION Off Pk	2.333	2.230	" "
TRANSITION Off Pk	0.877	0.877	" "
TRANSMISSION Off Pk	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	CENTS/KWH
RENEWABLE ENERGY	0.050	0.050	" "
TRANSIT RATE ADJ PEAK	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	1.120	1.120	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.452	7.452	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (W/O DEMAND)

			Current			**Proposed**			**DIFFERENCE**	
CUM % BILLS	KW	WINTER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		30	$12.94	$2.23	$10.71	$12.90	$2.23	$10.67	($0.04)	-0.3%
20		70	$19.34	$5.20	$14.14	$19.25	$5.20	$14.05	($0.09)	-0.5%
30		128	$28.63	$9.51	$19.12	$28.46	$9.51	$18.95	($0.17)	-0.6%
40		207	$41.26	$15.37	$25.89	$40.99	$15.37	$25.62	($0.27)	-0.7%
50		302	$56.47	$22.43	$34.04	$56.08	$22.43	$33.65	($0.39)	-0.7%
60		427	$76.47	$31.71	$44.76	$75.91	$31.71	$44.20	($0.56)	-0.7%
70		582	$101.27	$43.22	$58.05	$100.52	$43.22	$57.30	($0.75)	-0.7%
80		852	$144.47	$63.27	$81.20	$143.37	$63.27	$80.10	($1.10)	-0.8%
90		1,302	$216.48	$96.69	$119.79	$214.80	$96.69	$118.11	($1.68)	-0.8%
AVG.USE		615	$106.55	$45.67	$60.88	$105.75	$45.67	$60.08	($0.80)	-0.8%

Current

GENERAL RATE G-1 (W/O DEMAND)

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$8.14	PER BILL
DISTRIBUTION	7.441	4.642	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	2.270	2.270	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.002	0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1 (W/O DEMAND)

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$8.14	PER BILL
DISTRIBUTION	7.441	4.642	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	2.270	2.270	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.002	0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (W/O DEMAND)

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		23	$12.47	$1.71	$10.76	$12.44	$1.71	$10.73	($0.03)	-0.2%
20		57	$18.85	$4.23	$14.62	$18.78	$4.23	$14.55	($0.07)	-0.4%
30		111	$29.01	$8.24	$20.77	$28.86	$8.24	$20.62	($0.15)	-0.5%
40		182	$42.36	$13.52	$28.84	$42.13	$13.52	$28.61	($0.23)	-0.5%
50		279	$60.59	$20.72	$39.87	$60.23	$20.72	$39.51	($0.36)	-0.6%
60		392	$81.84	$29.11	$52.73	$81.33	$29.11	$52.22	($0.51)	-0.6%
70		555	$112.48	$41.21	$71.27	$111.76	$41.21	$70.55	($0.72)	-0.6%
80		785	$155.72	$58.29	$97.43	$154.70	$58.29	$96.41	($1.02)	-0.7%
90		1,275	$247.84	$94.68	$153.16	$246.19	$94.68	$151.51	($1.65)	-0.7%
AVG.USE		595	$120.00	$44.18	$75.82	$119.23	$44.18	$75.05	($0.77)	-0.6%

Current

GENERAL RATE G-1 (W/O DEMAND)

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$8.14	PER BILL
DISTRIBUTION	7.441	4.642	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	2.270	2.270	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.002	0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1 (W/O DEMAND)

DELIVERY SERVICES:

	Summer	Winter	
CUSTOMER		$8.14	PER BILL
DISTRIBUTION	7.441	4.642	CENTS/KWH
TRANSITION	0.783	0.783	" "
TRANSMISSION	2.270	2.270	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	0.002	0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

HRS USE= 150			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	1	150	$34.02	$11.14	$22.88	$33.82	$11.14	$22.68	($0.20)	-0.6%
20	2	300	$55.94	$22.28	$33.66	$55.55	$22.28	$33.27	($0.39)	-0.7%
30	3	450	$77.87	$33.42	$44.45	$77.28	$33.42	$43.86	($0.59)	-0.8%
40	3	450	$77.87	$33.42	$44.45	$77.28	$33.42	$43.86	($0.59)	-0.8%
50	4	600	$99.79	$44.56	$55.23	$99.02	$44.56	$54.46	($0.77)	-0.8%
60	5	750	$121.72	$55.70	$66.02	$120.75	$55.70	$65.05	($0.97)	-0.8%
70	6	900	$143.63	$66.83	$76.80	$142.47	$66.83	$75.64	($1.16)	-0.8%
80	6	900	$143.63	$66.83	$76.80	$142.47	$66.83	$75.64	($1.16)	-0.8%
90	8	1,200	$187.48	$89.11	$98.37	$185.93	$89.11	$96.82	($1.55)	-0.8%
AVG.USE	5	750	$121.72	$55.70	$66.02	$120.75	$55.70	$65.05	($0.97)	-0.8%

Current

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)	$0.00	$37.32	" "	
TRANSMISSION (winter)	$0.00	$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	" "
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)	$0.00	$37.32	" "	
TRANSMISSION (winter)	$0.00	$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

HRS USE= 150 CUM % BILLS	SUMMER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	1	150	$37.84	$11.14	$26.70	$37.65	$11.14	$26.51	($0.19)	-0.5%
20	2	300	$63.59	$22.28	$41.31	$63.21	$22.28	$40.93	($0.38)	-0.6%
30	3	450	$89.34	$33.42	$55.92	$88.76	$33.42	$55.34	($0.58)	-0.6%
40	4	600	$115.10	$44.56	$70.54	$114.32	$44.56	$69.76	($0.78)	-0.7%
50	4	600	$115.10	$44.56	$70.54	$114.32	$44.56	$69.76	($0.78)	-0.7%
60	5	750	$140.85	$55.70	$85.15	$139.88	$55.70	$84.18	($0.97)	-0.7%
70	6	900	$166.59	$66.83	$99.76	$165.43	$66.83	$98.60	($1.16)	-0.7%
80	7	1,050	$192.34	$77.97	$114.37	$190.99	$77.97	$113.02	($1.35)	-0.7%
90	8	1,200	$218.09	$89.11	$128.98	$216.54	$89.11	$127.43	($1.55)	-0.7%
AVG.USE	5	750	$140.85	$55.70	$85.15	$139.88	$55.70	$84.18	($0.97)	-0.7%

Current

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)	$0.00	$37.32	" "	
TRANSMISSION (winter)	$0.00	$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	" "
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)		$37.32	" "	
TRANSMISSION (winter)		$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

HRS USE= 300			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	1	300	$55.94	$22.28	$33.66	$55.55	$22.28	$33.27	($0.39)	-0.7%
20	2	600	$99.79	$44.56	$55.23	$99.02	$44.56	$54.46	($0.77)	-0.8%
30	3	900	$143.63	$66.83	$76.80	$142.47	$66.83	$75.64	($1.16)	-0.8%
40	3	900	$143.63	$66.83	$76.80	$142.47	$66.83	$75.64	($1.16)	-0.8%
50	4	1,200	$187.48	$89.11	$98.37	$185.93	$89.11	$96.82	($1.55)	-0.8%
60	5	1,500	$231.33	$111.39	$119.94	$229.40	$111.39	$118.01	($1.93)	-0.8%
70	6	1,800	$275.18	$133.67	$141.51	$272.86	$133.67	$139.19	($2.32)	-0.8%
80	6	1,800	$275.18	$133.67	$141.51	$272.86	$133.67	$139.19	($2.32)	-0.8%
90	8	2,400	$360.68	$178.22	$182.46	$357.58	$178.22	$179.36	($3.10)	-0.9%
AVG.USE	5	1,500	$231.33	$111.39	$119.94	$229.40	$111.39	$118.01	($1.93)	-0.8%

Current

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL
	FIRST 10 kw	OVER 10 kw	
DISTRIBUTION (summer)	$0.00	$0.86	PER KW
DISTRIBUTION (winter)	$0.00	$0.28	
TRANSMISSION (summer)	$0.00	$37.32	" "
TRANSMISSION (winter)	$0.00	$12.17	" "

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	" "
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL
	FIRST 10 kw	OVER 10 kw	
DISTRIBUTION (summer)	$0.00	$0.86	PER KW
DISTRIBUTION (winter)	$0.00	$0.28	
TRANSMISSION (summer)	$0.00	$37.32	" "
TRANSMISSION (winter)	$0.00	$12.17	" "

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

HRS USE= 300 CUM % BILLS	SUMMER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	1	300	$63.59	$22.28	$41.31	$63.21	$22.28	$40.93	($0.38)	-0.6%
20	2	600	$115.10	$44.56	$70.54	$114.32	$44.56	$69.76	($0.78)	-0.7%
30	3	900	$166.59	$66.83	$99.76	$165.43	$66.83	$98.60	($1.16)	-0.7%
40	4	1,200	$218.09	$89.11	$128.98	$216.54	$89.11	$127.43	($1.55)	-0.7%
50	4	1,200	$218.09	$89.11	$128.98	$216.54	$89.11	$127.43	($1.55)	-0.7%
60	5	1,500	$269.60	$111.39	$158.21	$267.66	$111.39	$156.27	($1.94)	-0.7%
70	6	1,800	$321.10	$133.67	$187.43	$318.78	$133.67	$185.11	($2.32)	-0.7%
80	7	2,100	$369.95	$155.95	$214.00	$367.24	$155.95	$211.29	($2.71)	-0.7%
90	8	2,400	$413.48	$178.22	$235.26	$410.38	$178.22	$232.16	($3.10)	-0.7%
AVG.USE	5	1,500	$269.60	$111.39	$158.21	$267.66	$111.39	$156.27	($1.94)	-0.7%

Current

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)	$0.00	$37.32	" "	
TRANSMISSION (winter)	$0.00	$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	" "
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

GENERAL RATE G-1 (WITH DEMAND)

DELIVERY SERVICES:

CUSTOMER		$12.09	PER BILL	
	FIRST 10 kw	OVER 10 kw		
DISTRIBUTION (summer)	$0.00	$0.86	PER KW	
DISTRIBUTION (winter)	$0.00	$0.28		
TRANSMISSION (summer)	$0.00	$37.32	" "	
TRANSMISSION (winter)	$0.00	$12.17	" "	
	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	6.809	4.155	2.606	CENTS/KWH
DISTRIBUTION (winter)	4.258	3.710	2.482	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	1.267	1.267	0.000	" "
TRANSMISSION (winter)	1.267	1.267	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSIT RATE ADJ (summer)	0.004	0.004	0.004	
TRANSIT RATE ADJ (winter)	0.004	0.004	0.004	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 200			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	8	1,600	$193.09	$118.82	$74.27	$191.03	$118.82	$72.21	($2.06)	-1.1%
20	10	2,000	$236.81	$148.52	$88.29	$234.23	$148.52	$85.71	($2.58)	-1.1%
30	12	2,400	$308.45	$178.22	$130.23	$305.35	$178.22	$127.13	($3.10)	-1.0%
40	14	2,800	$380.10	$207.93	$172.17	$376.49	$207.93	$168.56	($3.61)	-0.9%
50	16	3,200	$451.74	$237.63	$214.11	$447.61	$237.63	$209.98	($4.13)	-0.9%
60	20	4,000	$595.03	$297.04	$297.99	$589.87	$297.04	$292.83	($5.16)	-0.9%
70	24	4,800	$738.32	$356.45	$381.87	$732.13	$356.45	$375.68	($6.19)	-0.8%
80	33	6,600	$1,060.72	$490.12	$570.60	$1,052.21	$490.12	$562.09	($8.51)	-0.8%
90	49	9,800	$1,633.03	$727.75	$905.28	$1,620.39	$727.75	$892.64	($12.64)	-0.8%
AVG.USE	27	5,400	$845.78	$401.00	$444.78	$838.81	$401.00	$437.81	($6.97)	-0.8%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER		$18.19		PER BILL
		> 10 Kw		
DISTRIBUTION (summer)		$20.22		PER KVA
DISTRIBUTION (winter)		$9.43		
TRANSMISSION (summer)		$14.68		
TRANSMISSION (winter)		$5.54		

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER		$18.19		PER BILL
		> 10 Kw		
DISTRIBUTION (summer)		$20.22		PER KVA
DISTRIBUTION (winter)		$9.43		
TRANSMISSION (summer)		$14.68		
TRANSMISSION (winter)		$5.54		

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 200			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	9	1,800	$232.82	$133.67	$99.15	$230.50	$133.67	$96.83	($2.32)	-1.0%
20	10	2,000	$256.67	$148.52	$108.15	$254.09	$148.52	$105.57	($2.58)	-1.0%
30	12	2,400	$368.86	$178.22	$190.64	$365.77	$178.22	$187.55	($3.09)	-0.8%
40	15	3,000	$537.16	$222.78	$314.38	$533.29	$222.78	$310.51	($3.87)	-0.7%
50	18	3,600	$705.46	$267.34	$438.12	$700.81	$267.34	$433.47	($4.65)	-0.7%
60	21	4,200	$873.75	$311.89	$561.86	$868.33	$311.89	$556.44	($5.42)	-0.6%
70	26	5,200	$1,154.24	$386.15	$768.09	$1,147.53	$386.15	$761.38	($6.71)	-0.6%
80	36	7,200	$1,715.22	$534.67	$1,180.55	$1,705.93	$534.67	$1,171.26	($9.29)	-0.5%
90	54	10,800	$2,722.81	$802.01	$1,920.80	$2,708.88	$802.01	$1,906.87	($13.93)	-0.5%
AVG.USE	29	5,800	$1,322.53	$430.71	$891.82	$1,315.05	$430.71	$884.34	($7.48)	-0.6%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 250			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	8	2,000	$236.81	$148.52	$88.29	$234.23	$148.52	$85.71	($2.58)	-1.1%
20	10	2,500	$288.94	$185.65	$103.29	$285.72	$185.65	$100.07	($3.22)	-1.1%
30	12	3,000	$371.01	$222.78	$148.23	$367.14	$222.78	$144.36	($3.87)	-1.0%
40	14	3,500	$453.08	$259.91	$193.17	$448.57	$259.91	$188.66	($4.51)	-1.0%
50	16	4,000	$535.15	$297.04	$238.11	$529.99	$297.04	$232.95	($5.16)	-1.0%
60	20	5,000	$699.29	$371.30	$327.99	$692.84	$371.30	$321.54	($6.45)	-0.9%
70	24	6,000	$862.68	$445.56	$417.12	$854.94	$445.56	$409.38	($7.74)	-0.9%
80	33	8,250	$1,230.32	$612.65	$617.67	$1,219.68	$612.65	$607.03	($10.64)	-0.9%
90	49	12,250	$1,883.89	$909.69	$974.20	$1,868.08	$909.69	$958.39	($15.81)	-0.8%
AVG.USE	27	6,750	$985.23	$501.26	$483.97	$976.52	$501.26	$475.26	($8.71)	-0.9%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 250			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	9	2,250	$283.17	$167.09	$116.08	$280.27	$167.09	$113.18	($2.90)	-1.0%
20	10	2,500	$309.67	$185.65	$124.02	$306.44	$185.65	$120.79	($3.23)	-1.0%
30	12	3,000	$432.46	$222.78	$209.68	$428.59	$222.78	$205.81	($3.87)	-0.9%
40	15	3,750	$616.66	$278.48	$338.18	$611.82	$278.48	$333.34	($4.84)	-0.8%
50	18	4,500	$800.85	$334.17	$466.68	$795.04	$334.17	$460.87	($5.81)	-0.7%
60	21	5,250	$984.73	$389.87	$594.86	$977.96	$389.87	$588.09	($6.77)	-0.7%
70	26	6,500	$1,290.16	$482.69	$807.47	$1,281.77	$482.69	$799.08	($8.39)	-0.7%
80	36	9,000	$1,901.02	$668.34	$1,232.68	$1,889.41	$668.34	$1,221.07	($11.61)	-0.6%
90	54	13,500	$3,000.58	$1,002.51	$1,998.07	$2,983.17	$1,002.51	$1,980.66	($17.41)	-0.6%
AVG.USE	29	7,250	$1,473.42	$538.39	$935.03	$1,464.07	$538.39	$925.68	($9.35)	-0.6%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

	> 10 Kw	
CUSTOMER	$18.19	PER BILL
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

	> 10 Kw	
CUSTOMER	$18.19	PER BILL
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 300			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	8	3,200	$361.92	$237.63	$124.29	$357.79	$237.63	$120.16	($4.13)	-1.1%
20	10	4,000	$444.40	$297.04	$147.36	$439.24	$297.04	$142.20	($5.16)	-1.2%
30	12	4,800	$556.81	$356.45	$200.36	$550.62	$356.45	$194.17	($6.19)	-1.1%
40	14	5,600	$669.23	$415.86	$253.37	$662.00	$415.86	$246.14	($7.23)	-1.1%
50	16	6,400	$781.63	$475.26	$306.37	$773.37	$475.26	$298.11	($8.26)	-1.1%
60	20	8,000	$1,006.46	$594.08	$412.38	$996.14	$594.08	$402.06	($10.32)	-1.0%
70	24	9,600	$1,231.29	$712.90	$518.39	$1,218.91	$712.90	$506.01	($12.38)	-1.0%
80	33	13,200	$1,737.14	$980.23	$756.91	$1,720.11	$980.23	$739.88	($17.03)	-1.0%
90	49	19,600	$2,636.45	$1,455.50	$1,180.95	$2,611.17	$1,455.50	$1,155.67	($25.28)	-1.0%
AVG.USE	27	10,800	$1,399.91	$802.01	$597.90	$1,385.98	$802.01	$583.97	($13.93)	-1.0%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER		$18.19		PER BILL
		> 10 Kw		
DISTRIBUTION	(summer)	$20.22		PER KVA
DISTRIBUTION	(winter)	$9.43		
TRANSMISSION	(summer)	$14.68		
TRANSMISSION	(winter)	$5.54		

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER		$18.19		PER BILL
		> 10 Kw		
DISTRIBUTION	(summer)	$20.22		PER KVA
DISTRIBUTION	(winter)	$9.43		
TRANSMISSION	(summer)	$14.68		
TRANSMISSION	(winter)	$5.54		

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

HOURS USE 300			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	9	3,600	$425.48	$267.34	$158.14	$420.84	$267.34	$153.50	($4.64)	-1.1%
20	10	4,000	$467.10	$297.04	$170.06	$461.94	$297.04	$164.90	($5.16)	-1.1%
30	12	4,800	$620.13	$356.45	$263.68	$613.94	$356.45	$257.49	($6.19)	-1.0%
40	15	6,000	$849.69	$445.56	$404.13	$841.95	$445.56	$396.39	($7.74)	-0.9%
50	18	7,200	$1,079.24	$534.67	$544.57	$1,069.95	$534.67	$535.28	($9.29)	-0.9%
60	21	8,400	$1,308.79	$623.78	$685.01	$1,297.96	$623.78	$674.18	($10.83)	-0.8%
70	26	10,400	$1,691.39	$772.30	$919.09	$1,677.97	$772.30	$905.67	($13.42)	-0.8%
80	36	14,400	$2,456.57	$1,069.34	$1,387.23	$2,438.00	$1,069.34	$1,368.66	($18.57)	-0.8%
90	54	21,600	$3,833.91	$1,604.02	$2,229.89	$3,806.05	$1,604.02	$2,202.03	($27.86)	-0.7%
AVG.USE	29	11,600	$1,920.95	$861.42	$1,059.53	$1,905.99	$861.42	$1,044.57	($14.96)	-0.8%

Current

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.578	0.578	0.578	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL RATE G-2

DELIVERY SERVICES:

CUSTOMER	$18.19	PER BILL
	> 10 Kw	
DISTRIBUTION (summer)	$20.22	PER KVA
DISTRIBUTION (winter)	$9.43	
TRANSMISSION (summer)	$14.68	
TRANSMISSION (winter)	$5.54	

	1st 2000 kwh	next 150 hrs	additional kwh	
DISTRIBUTION (summer)	2.834	1.509	1.198	CENTS/KWH
DISTRIBUTION (winter)	1.841	1.336	1.149	" "
TRANSITION (summer)	0.783	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	0.783	" "
TRANSMISSION (summer)	0.000	0.000	0.000	" "
TRANSMISSION (winter)	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
TRANSITION RATE ADJ	0.003	0.003	0.003	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DIST ADJ	0.449	0.449	0.449	" "

SUPPLIER SERVICES:

DEAULT SERVI CE - FIXED	7.372	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE 350 CUM % BILLS	WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	92	32,200	$4,664.30	$2,330.96	$2,333.34	$4,622.76	$2,330.96	$2,291.80	-$41.54	-0.9%
20	160	56,000	$7,936.59	$4,053.84	$3,882.75	$7,864.35	$4,053.84	$3,810.51	-$72.24	-0.9%
30	317	110,950	$15,491.74	$8,031.67	$7,460.07	$15,348.62	$8,031.67	$7,316.95	-$143.12	-0.9%
40	471	164,850	$22,902.53	$11,933.49	$10,969.04	$22,689.87	$11,933.49	$10,756.38	-$212.66	-0.9%
50	567	198,450	$27,522.25	$14,365.80	$13,156.45	$27,266.25	$14,365.80	$12,900.45	-$256.00	-0.9%
60	679	237,650	$32,911.90	$17,203.48	$15,708.42	$32,605.34	$17,203.48	$15,401.86	-$306.56	-0.9%
70	1,019	356,650	$49,273.38	$25,817.89	$23,455.49	$48,813.31	$25,817.89	$22,995.42	-$460.07	-0.9%
80	1,545	540,750	$74,585.56	$39,144.89	$35,440.67	$73,887.99	$39,144.89	$34,743.10	-$697.57	-0.9%
90	2,368	828,800	$114,189.96	$59,996.83	$54,193.13	$113,120.81	$59,996.83	$53,123.98	-$1,069.15	-0.9%
AVG.USE	1,171	409,850	$56,587.93	$29,669.04	$26,918.89	$56,059.22	$29,669.04	$26,390.18	-$528.71	-0.9%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION	(summer)		$14.83	PER KVA
DISTRIBUTION	(winter)		$8.86	
TRANSITION	(summer)		$2.73	
TRANSITION	(winter)		$2.73	
TRANSMISSION	(summer)		$7.37	
TRANSMISSION	(winter)		$7.37	

		PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION	(summer)		$14.83	PER KVA
DISTRIBUTION	(winter)		$8.86	
TRANSITION	(summer)		$2.73	
TRANSITION	(winter)		$2.73	
TRANSMISSION	(summer)		$7.37	
TRANSMISSION	(winter)		$7.37	

		PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE 350 CUM % BILLS	SUMMER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	96	33,600	$5,429.90	$2,432.30	$2,997.60	$5,386.55	$2,432.30	$2,954.25	-$43.35	-0.8%
20	196	68,600	$10,839.10	$4,965.95	$5,873.15	$10,750.60	$4,965.95	$5,784.65	-$88.50	-0.8%
30	346	121,100	$18,952.90	$8,766.43	$10,186.47	$18,796.68	$8,766.43	$10,030.25	-$156.22	-0.8%
40	516	180,600	$28,148.54	$13,073.63	$15,074.91	$27,915.56	$13,073.63	$14,841.93	-$232.98	-0.8%
50	620	217,000	$33,774.11	$15,708.63	$18,065.48	$33,494.18	$15,708.63	$17,785.55	-$279.93	-0.8%
60	837	292,950	$45,512.07	$21,206.65	$24,305.42	$45,134.17	$21,206.65	$23,927.52	-$377.90	-0.8%
70	1,134	396,900	$61,577.40	$28,731.59	$32,845.81	$61,065.40	$28,731.59	$32,333.81	-$512.00	-0.8%
80	1,724	603,400	$93,491.68	$43,680.13	$49,811.55	$92,713.30	$43,680.13	$49,033.17	-$778.38	-0.8%
90	2,906	1,017,100	$157,428.42	$73,627.87	$83,800.55	$156,116.36	$73,627.87	$82,488.49	-$1,312.06	-0.8%
AVG.USE	1,373	480,550	$74,505.38	$34,787.01	$39,718.37	$73,885.47	$34,787.01	$39,098.46	-$619.91	-0.8%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	
	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	
	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE CUM % BILLS	450 WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	92	41,400	$5,430.84	$2,996.95	$2,433.89	$5,377.44	$2,996.95	$2,380.49	-$53.40	-1.0%
20	160	72,000	$9,269.71	$5,212.08	$4,057.63	$9,176.83	$5,212.08	$3,964.75	-$92.88	-1.0%
30	317	142,650	$18,132.98	$10,326.43	$7,806.55	$17,948.97	$10,326.43	$7,622.54	-$184.01	-1.0%
40	471	211,950	$26,826.90	$15,343.06	$11,483.84	$26,553.49	$15,343.06	$11,210.43	-$273.41	-1.0%
50	567	255,150	$32,246.49	$18,470.31	$13,776.18	$31,917.35	$18,470.31	$13,447.04	-$329.14	-1.0%
60	679	305,550	$38,569.33	$22,118.76	$16,450.57	$38,175.17	$22,118.76	$16,056.41	-$394.16	-1.0%
70	1,019	458,550	$57,763.69	$33,194.43	$24,569.26	$57,172.16	$33,194.43	$23,977.73	-$591.53	-1.0%
80	1,545	695,250	$87,458.50	$50,329.15	$37,129.35	$86,561.63	$50,329.15	$36,232.48	-$896.87	-1.0%
90	2,368	1,065,600	$133,920.14	$77,138.78	$56,781.36	$132,545.51	$77,138.78	$55,406.73	-$1,374.63	-1.0%
AVG.USE	1,171	526,950	$66,344.70	$38,145.91	$28,198.79	$65,664.94	$38,145.91	$27,519.03	-$679.76	-1.0%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	96	43,200	$6,229.78	$3,127.25	$3,102.53	$6,174.05	$3,127.25	$3,046.80	-$55.73	-0.9%
20	196	88,200	$12,472.18	$6,384.80	$6,087.38	$12,358.40	$6,384.80	$5,973.60	-$113.78	-0.9%
30	346	155,700	$21,835.77	$11,271.12	$10,564.65	$21,634.92	$11,271.12	$10,363.80	-$200.85	-0.9%
40	516	232,200	$32,447.86	$16,808.96	$15,638.90	$32,148.32	$16,808.96	$15,339.36	-$299.54	-0.9%
50	620	279,000	$38,939.95	$20,196.81	$18,743.14	$38,580.04	$20,196.81	$18,383.23	-$359.91	-0.9%
60	837	376,650	$52,485.95	$27,265.69	$25,220.26	$52,000.08	$27,265.69	$24,734.39	-$485.87	-0.9%
70	1,134	510,300	$71,025.89	$36,940.62	$34,085.27	$70,367.60	$36,940.62	$33,426.98	-$658.29	-0.9%
80	1,724	775,800	$107,856.04	$56,160.16	$51,695.88	$106,855.26	$56,160.16	$50,695.10	-$1,000.78	-0.9%
90	2,906	1,307,700	$181,641.21	$94,664.40	$86,976.81	$179,954.28	$94,664.40	$85,289.88	-$1,686.93	-0.9%
AVG.USE	1,373	617,850	$85,945.22	$44,726.16	$41,219.06	$85,148.19	$44,726.16	$40,422.03	-$797.03	-0.9%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE CUM % BILLS	500 WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	92	46,000	$5,814.11	$3,329.94	$2,484.17	$5,754.77	$3,329.94	$2,424.83	-$59.34	-1.0%
20	160	80,000	$9,936.27	$5,791.20	$4,145.07	$9,833.07	$5,791.20	$4,041.87	-$103.20	-1.0%
30	317	158,500	$19,453.62	$11,473.82	$7,979.80	$19,249.15	$11,473.82	$7,775.33	-$204.47	-1.1%
40	471	235,500	$28,789.10	$17,047.85	$11,741.25	$28,485.30	$17,047.85	$11,437.45	-$303.80	-1.1%
50	567	283,500	$34,608.62	$20,522.57	$14,086.05	$34,242.90	$20,522.57	$13,720.33	-$365.72	-1.1%
60	679	339,500	$41,398.06	$24,576.41	$16,821.65	$40,960.10	$24,576.41	$16,383.69	-$437.96	-1.1%
70	1,019	509,500	$62,008.86	$36,882.71	$25,126.15	$61,351.60	$36,882.71	$24,468.89	-$657.26	-1.1%
80	1,545	772,500	$93,894.98	$55,921.28	$37,973.70	$92,898.45	$55,921.28	$36,977.17	-$996.53	-1.1%
90	2,368	1,184,000	$143,785.23	$85,709.76	$58,075.47	$142,257.87	$85,709.76	$56,548.11	-$1,527.36	-1.1%
AVG.USE	1,171	585,500	$71,223.10	$42,384.35	$28,838.75	$70,467.80	$42,384.35	$28,083.45	-$755.30	-1.1%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - NEMA

HOURS USE 500			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	96	48,000	$6,629.71	$3,474.72	$3,154.99	$6,567.79	$3,474.72	$3,093.07	-$61.92	-0.9%
20	196	98,000	$13,288.71	$7,094.22	$6,194.49	$13,162.29	$7,094.22	$6,068.07	-$126.42	-1.0%
30	346	173,000	$23,277.21	$12,523.47	$10,753.74	$23,054.04	$12,523.47	$10,530.57	-$223.17	-1.0%
40	516	258,000	$34,597.51	$18,676.62	$15,920.89	$34,264.69	$18,676.62	$15,588.07	-$332.82	-1.0%
50	620	310,000	$41,522.87	$22,440.90	$19,081.97	$41,122.97	$22,440.90	$18,682.07	-$399.90	-1.0%
60	837	418,500	$55,972.91	$30,295.22	$25,677.69	$55,433.04	$30,295.22	$25,137.82	-$539.87	-1.0%
70	1,134	567,000	$75,750.13	$41,045.13	$34,705.00	$75,018.70	$41,045.13	$33,973.57	-$731.43	-1.0%
80	1,724	862,000	$115,038.23	$62,400.18	$52,638.05	$113,926.25	$62,400.18	$51,526.07	-$1,111.98	-1.0%
90	2,906	1,453,000	$193,747.61	$105,182.67	$88,564.94	$191,873.24	$105,182.67	$86,690.57	-$1,874.37	-1.0%
AVG.USE	1,373	686,500	$91,665.15	$49,695.74	$41,969.41	$90,779.56	$49,695.74	$41,083.82	-$885.59	-1.0%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION (summer)			$14.83	PER KVA
DISTRIBUTION (winter)			$8.86	
TRANSITION (summer)			$2.73	
TRANSITION (winter)			$2.73	
TRANSMISSION (summer)			$7.37	
TRANSMISSION (winter)			$7.37	

	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION (summer)			$14.83	PER KVA
DISTRIBUTION (winter)			$8.86	
TRANSITION (summer)			$2.73	
TRANSITION (winter)			$2.73	
TRANSMISSION (summer)			$7.37	
TRANSMISSION (winter)			$7.37	

	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL TOU RATE T-1

	WINTER		Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		200	$42.99	$14.85	$28.14	$42.73	$14.85	$27.88	-$0.26	-0.6%
20		300	$59.42	$22.28	$37.14	$59.03	$22.28	$36.75	-$0.39	-0.7%
30		500	$92.28	$37.13	$55.15	$91.63	$37.13	$54.50	-$0.65	-0.7%
40		600	$108.71	$44.56	$64.15	$107.94	$44.56	$63.38	-$0.77	-0.7%
50		700	$125.14	$51.98	$73.16	$124.23	$51.98	$72.25	-$0.91	-0.7%
60		800	$141.57	$59.41	$82.16	$140.54	$59.41	$81.13	-$1.03	-0.7%
70		1,000	$174.43	$74.26	$100.17	$173.14	$74.26	$98.88	-$1.29	-0.7%
80		1,200	$207.29	$89.11	$118.18	$205.74	$89.11	$116.63	-$1.55	-0.7%
90		1,400	$240.14	$103.96	$136.18	$238.34	$103.96	$134.38	-$1.80	-0.7%
AVG.USE		1,265	$217.97	$93.94	$124.03	$216.34	$93.94	$122.40	-$1.63	-0.7%

Current

GENERAL TOU RATE T-1

DELIVERY SERVICES:

	PEAK	OFF-PEAK	
CUSTOMER		$10.13	PER BILL
	58.08%	41.92%	
DISTRIBUTION (summer)	15.764	2.128	CENTS/KWH
DISTRIBUTION (winter)	7.421	1.934	" "
TRANSITION (summer)	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	" "
TRANSMISSION (summer)	8.071	0.000	" "
TRANSMISSION (winter)	3.826	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ (summer)	0.000	0.000	" "
TRANSITION RATE ADJ (winter)	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

GENERAL TOU RATE T-1

DELIVERY SERVICES:

	PEAK	OFF-PEAK	
CUSTOMER		$10.13	PER BILL
	58.08%	41.92%	
DISTRIBUTION (summer)	15.764	2.128	CENTS/KWH
DISTRIBUTION (winter)	7.421	1.934	" "
TRANSITION (summer)	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	" "
TRANSMISSION (summer)	8.071	0.000	" "
TRANSMISSION (winter)	3.826	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ (summer)	0.000	0.000	
TRANSITION RATE ADJ (winter)	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
GENERAL TOU RATE T-1

	SUMMER		Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		200	$56.14	$14.85	$41.29	$55.88	$14.85	$41.03	-$0.26	-0.5%
20		300	$79.15	$22.28	$56.87	$78.76	$22.28	$56.48	-$0.39	-0.5%
30		500	$125.16	$37.13	$88.03	$124.52	$37.13	$87.39	-$0.64	-0.5%
40		600	$148.17	$44.56	$103.61	$147.40	$44.56	$102.84	-$0.77	-0.5%
50		700	$171.17	$51.98	$119.19	$170.27	$51.98	$118.29	-$0.90	-0.5%
60		800	$194.19	$59.41	$134.78	$193.15	$59.41	$133.74	-$1.04	-0.5%
70		1,000	$240.20	$74.26	$165.94	$238.91	$74.26	$164.65	-$1.29	-0.5%
80		1,200	$286.21	$89.11	$197.10	$284.66	$89.11	$195.55	-$1.55	-0.5%
90		1,400	$332.22	$103.96	$228.26	$330.41	$103.96	$226.45	-$1.81	-0.5%
AVG.USE		969	$233.07	$71.96	$161.11	$231.82	$71.96	$159.86	-$1.25	-0.5%

Current

GENERAL TOU RATE T-1

DELIVERY SERVICES:

	PEAK 54.32%	OFF-PEAK 45.68%	
CUSTOMER		$10.13	PER BILL
DISTRIBUTION (summer)	15.764	2.128	CENTS/KWH
DISTRIBUTION (winter)	7.421	1.934	" "
TRANSITION (summer)	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	" "
TRANSMISSION (summer)	8.071	0.000	" "
TRANSMISSION (winter)	3.826	0.000	" "
DEMAND-SIDE MGT	0.250	0.000	" "
RENEWABLE ENERGY	0.050	0.000	" "
TRANSITION RATE ADJ (summer)	0.000	0.000	" "
TRANSITION RATE ADJ (winter)	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

GENERAL TOU RATE T-1

DELIVERY SERVICES:

	PEAK 54.32%	OFF-PEAK 45.68%	
CUSTOMER		$10.13	PER BILL
DISTRIBUTION (summer)	15.764	2.128	CENTS/KWH
DISTRIBUTION (winter)	7.421	1.934	" "
TRANSITION (summer)	0.783	0.783	" "
TRANSITION (winter)	0.783	0.783	" "
TRANSMISSION (summer)	8.071	0.000	" "
TRANSMISSION (winter)	3.826	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ (summer)	0.000	0.000	
TRANSITION RATE ADJ (winter)	0.000	0.000	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use 350 CUM % BILLS	WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	48	16,800	$2,421.91	$1,216.15	$1,205.76	$2,400.24	$1,216.15	$1,184.09	-$21.67	-0.9%
20	74	25,900	$3,718.74	$1,874.90	$1,843.84	$3,685.33	$1,874.90	$1,810.43	-$33.41	-0.9%
30	124	43,400	$6,212.65	$3,141.73	$3,070.92	$6,156.66	$3,141.73	$3,014.93	-$55.99	-0.9%
40	145	50,750	$7,260.08	$3,673.79	$3,586.29	$7,194.61	$3,673.79	$3,520.82	-$65.47	-0.9%
50	179	62,650	$9,042.78	$4,535.23	$4,507.55	$8,961.96	$4,535.23	$4,426.73	-$80.82	-0.9%
60	224	78,400	$11,287.30	$5,675.38	$5,611.92	$11,186.16	$5,675.38	$5,510.78	-$101.14	-0.9%
70	285	99,750	$14,329.85	$7,220.90	$7,108.95	$14,201.17	$7,220.90	$6,980.27	-$128.68	-0.9%
80	375	131,250	$18,870.92	$9,501.19	$9,369.73	$18,701.61	$9,501.19	$9,200.42	-$169.31	-0.9%
90	528	184,800	$26,502.25	$13,377.67	$13,124.58	$26,263.86	$13,377.67	$12,886.19	-$238.39	-0.9%
AVG.USE	316	110,600	$15,928.11	$8,006.33	$7,921.78	$15,785.44	$8,006.33	$7,779.11	-$142.67	-0.9%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use 350 CUM % BILLS	SUMMER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	48	16,800	$2,827.51	$1,216.15	$1,611.36	$2,805.84	$1,216.15	$1,589.69	-$21.67	-0.8%
20	82	28,700	$4,810.66	$2,077.59	$2,733.07	$4,773.64	$2,077.59	$2,696.05	-$37.02	-0.8%
30	121	42,350	$7,085.46	$3,065.72	$4,019.74	$7,030.83	$3,065.72	$3,965.11	-$54.63	-0.8%
40	156	54,600	$9,213.78	$3,952.49	$5,261.29	$9,143.35	$3,952.49	$5,190.86	-$70.43	-0.8%
50	202	70,700	$11,896.87	$5,117.97	$6,778.90	$11,805.67	$5,117.97	$6,687.70	-$91.20	-0.8%
60	239	83,650	$14,055.01	$6,055.42	$7,999.59	$13,947.10	$6,055.42	$7,891.68	-$107.91	-0.8%
70	307	107,450	$18,073.37	$7,778.31	$10,295.06	$17,934.76	$7,778.31	$10,156.45	-$138.61	-0.8%
80	407	142,450	$23,906.17	$10,311.96	$13,594.21	$23,722.41	$10,311.96	$13,410.45	-$183.76	-0.8%
90	572	200,200	$33,530.29	$14,492.48	$19,037.81	$33,272.03	$14,492.48	$18,779.55	-$258.26	-0.8%
AVG.USE	337	117,950	$19,823.21	$8,538.40	$11,284.81	$19,671.05	$8,538.40	$11,132.65	-$152.16	-0.8%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:				
CUSTOMER	KW < 150	$27.77		PER BILL
	150<KW<=300	$114.62		
	300<KW<=100	$166.67		
	KW > 1000	$374.57		
DISTRIBUTION (summer)		$19.88		PER KVA
DISTRIBUTION (winter)		$11.43		
TRANSITION (summer)		$1.66		
TRANSITION (winter)		$1.66		
TRANSMISSION (summer)		$7.08		
TRANSMISSION (winter)		$7.08		
	PEAK 37.67%	OFF-PEAK 62.33%		
TRANSITION (summer)	0.376	0.376		CENTS/KWH
TRANSITION (winter)	0.376	0.376		" "
DEMAND-SIDE MGT	0.250	0.250		" "
RENEWABLE ENERGY	0.050	0.050		" "
TRANSITION RATE ADJ	-0.005	-0.005		" "
DEFAULT SERV ADJ	0.000	0.000		" "
DIST ADJ	0.578	0.578		" "
SUPPLIER SERVICES:				
DEFAULT SERVICE NEMA - FIXED	7.185	7.185		CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054		

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:				
CUSTOMER	KW < 150	$27.77		PER BILL
	150<KW<=300	$114.62		
	300<KW<=100	$166.67		
	KW > 1000	$374.57		
DISTRIBUTION (summer)		$19.88		PER KVA
DISTRIBUTION (winter)		$11.43		
TRANSITION (summer)		$1.66		
TRANSITION (winter)		$1.66		
TRANSMISSION (summer)		$7.08		
TRANSMISSION (winter)		$7.08		
	PEAK 37.67%	OFF-PEAK 62.33%		
TRANSITION (summer)	0.376	0.376		CENTS/KWH
TRANSITION (winter)	0.376	0.376		" "
DEMAND-SIDE MGT	0.250	0.250		" "
RENEWABLE ENERGY	0.050	0.050		" "
TRANSITION RATE ADJ	-0.005	-0.005		" "
DEFAULT SERV ADJ	0.000	0.000		" "
DIST ADJ	0.449	0.449		" "
SUPPLIER SERVICES:				
DEFAULT SERVICE NEMA - FIXED	7.185	7.185		CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054		" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use 400			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	48	19,200	$2,625.63	$1,389.89	$1,235.74	$2,600.86	$1,389.89	$1,210.97	-$24.77	-0.9%
20	74	29,600	$4,032.79	$2,142.74	$1,890.05	$3,994.61	$2,142.74	$1,851.87	-$38.18	-0.9%
30	124	49,600	$6,738.89	$3,590.54	$3,148.35	$6,674.91	$3,590.54	$3,084.37	-$63.98	-0.9%
40	145	58,000	$7,875.46	$4,198.62	$3,676.84	$7,800.64	$4,198.62	$3,602.02	-$74.82	-1.0%
50	179	71,600	$9,802.45	$5,183.12	$4,619.33	$9,710.09	$5,183.12	$4,526.97	-$92.36	-0.9%
60	224	89,600	$12,237.94	$6,486.14	$5,751.80	$12,122.36	$6,486.14	$5,636.22	-$115.58	-0.9%
70	285	114,000	$15,539.39	$8,252.46	$7,286.93	$15,392.33	$8,252.46	$7,139.87	-$147.06	-0.9%
80	375	150,000	$20,462.42	$10,858.50	$9,603.92	$20,268.92	$10,858.50	$9,410.42	-$193.50	-0.9%
90	528	211,200	$28,743.09	$15,288.77	$13,454.32	$28,470.64	$15,288.77	$13,181.87	-$272.45	-0.9%
AVG.USE	316	126,400	$17,269.23	$9,150.10	$8,119.13	$17,106.17	$9,150.10	$7,956.07	-$163.06	-0.9%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:				
CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

		PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION	(summer)	0.376	0.376	CENTS/KWH
TRANSITION	(winter)	0.376	0.376	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.005	-0.005	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.578	0.578	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE	NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:				
CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

		PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION	(summer)	0.376	0.376	CENTS/KWH
TRANSITION	(winter)	0.376	0.376	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.005	-0.005	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.449	0.449	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE	NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER		0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use 400			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	48	19,200	$3,031.23	$1,389.89	$1,641.34	$3,006.46	$1,389.89	$1,616.57	-$24.77	-0.8%
20	82	32,800	$5,158.67	$2,374.39	$2,784.28	$5,116.36	$2,374.39	$2,741.97	-$42.31	-0.8%
30	121	48,400	$7,598.99	$3,503.68	$4,095.31	$7,536.55	$3,503.68	$4,032.87	-$62.44	-0.8%
40	156	62,400	$9,875.86	$4,517.14	$5,358.72	$9,795.36	$4,517.14	$5,278.22	-$80.50	-0.8%
50	202	80,800	$12,754.16	$5,849.11	$6,905.05	$12,649.93	$5,849.11	$6,800.82	-$104.23	-0.8%
60	239	95,600	$15,069.32	$6,920.48	$8,148.84	$14,946.00	$6,920.48	$8,025.52	-$123.32	-0.8%
70	307	122,800	$19,376.27	$8,889.49	$10,486.78	$19,217.86	$8,889.49	$10,328.37	-$158.41	-0.8%
80	407	162,800	$25,633.47	$11,785.09	$13,848.38	$25,423.46	$11,785.09	$13,638.37	-$210.01	-0.8%
90	572	228,800	$35,957.85	$16,562.83	$19,395.02	$35,662.70	$16,562.83	$19,099.87	-$295.15	-0.8%
AVG.USE	337	134,800	$21,253.43	$9,758.17	$11,495.26	$21,079.54	$9,758.17	$11,321.37	-$173.89	-0.8%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use	450		Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	48	21,600	$2,829.33	$1,563.62	$1,265.71	$2,801.47	$1,563.62	$1,237.85	-$27.86	-1.0%
20	74	33,300	$4,346.86	$2,410.59	$1,936.27	$4,303.90	$2,410.59	$1,893.31	-$42.96	-1.0%
30	124	55,800	$7,265.15	$4,039.36	$3,225.79	$7,193.17	$4,039.36	$3,153.81	-$71.98	-1.0%
40	145	65,250	$8,490.84	$4,723.45	$3,767.39	$8,406.67	$4,723.45	$3,683.22	-$84.17	-1.0%
50	179	80,550	$10,562.13	$5,831.01	$4,731.12	$10,458.22	$5,831.01	$4,627.21	-$103.91	-1.0%
60	224	100,800	$13,188.60	$7,296.91	$5,891.69	$13,058.57	$7,296.91	$5,761.66	-$130.03	-1.0%
70	285	128,250	$16,748.93	$9,284.02	$7,464.91	$16,583.49	$9,284.02	$7,299.47	-$165.44	-1.0%
80	375	168,750	$22,053.92	$12,215.81	$9,838.11	$21,836.23	$12,215.81	$9,620.42	-$217.69	-1.0%
90	528	237,600	$30,983.91	$17,199.86	$13,784.05	$30,677.41	$17,199.86	$13,477.55	-$306.50	-1.0%
AVG.USE	316	142,200	$18,610.33	$10,293.86	$8,316.47	$18,426.89	$10,293.86	$8,133.03	-$183.44	-1.0%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - NEMA

Hours Use 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	48	21,600	$3,234.93	$1,563.62	$1,671.31	$3,207.07	$1,563.62	$1,643.45	-$27.86	-0.9%
20	82	36,900	$5,506.68	$2,671.19	$2,835.49	$5,459.08	$2,671.19	$2,787.89	-$47.60	-0.9%
30	121	54,450	$8,112.51	$3,941.64	$4,170.87	$8,042.27	$3,941.64	$4,100.63	-$70.24	-0.9%
40	156	70,200	$10,537.92	$5,081.78	$5,456.14	$10,447.36	$5,081.78	$5,365.58	-$90.56	-0.9%
50	202	90,900	$13,611.45	$6,580.25	$7,031.20	$13,494.19	$6,580.25	$6,913.94	-$117.26	-0.9%
60	239	107,550	$16,083.64	$7,785.54	$8,298.10	$15,944.90	$7,785.54	$8,159.36	-$138.74	-0.9%
70	307	138,150	$20,679.18	$10,000.68	$10,678.50	$20,500.97	$10,000.68	$10,500.29	-$178.21	-0.9%
80	407	183,150	$27,360.78	$13,258.23	$14,102.55	$27,124.52	$13,258.23	$13,866.29	-$236.26	-0.9%
90	572	257,400	$38,385.43	$18,633.19	$19,752.24	$38,053.38	$18,633.19	$19,420.19	-$332.05	-0.9%
AVG.USE	337	151,650	$22,683.66	$10,977.94	$11,705.72	$22,488.03	$10,977.94	$11,510.09	-$195.63	-0.9%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:			
CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK	OFF-PEAK	
	37.67%	62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:			
CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK	OFF-PEAK	
	37.67%	62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE NEMA - FIXED	7.185	7.185	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE 350			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	78	27,300	$3,936.81	$1,922.47	$2,014.34	$3,901.59	$1,922.47	$1,979.12	-$35.22	-0.9%
20	131	45,850	$6,450.73	$3,228.76	$3,221.97	$6,391.58	$3,228.76	$3,162.82	-$59.15	-0.9%
30	223	78,050	$10,814.52	$5,496.28	$5,318.24	$10,713.83	$5,496.28	$5,217.55	-$100.69	-0.9%
40	246	86,100	$11,905.46	$6,063.16	$5,842.30	$11,794.39	$6,063.16	$5,731.23	-$111.07	-0.9%
50	339	118,650	$16,316.68	$8,355.33	$7,961.35	$16,163.63	$8,355.33	$7,808.30	-$153.05	-0.9%
60	448	156,800	$21,486.83	$11,041.86	$10,444.97	$21,284.56	$11,041.86	$10,242.70	-$202.27	-0.9%
70	553	193,550	$26,467.24	$13,629.79	$12,837.45	$26,217.56	$13,629.79	$12,587.77	-$249.68	-0.9%
80	1,193	417,550	$56,824.04	$29,403.87	$27,420.17	$56,285.40	$29,403.87	$26,881.53	-$538.64	-0.9%
90	1,499	524,650	$71,338.38	$36,945.85	$34,392.53	$70,661.59	$36,945.85	$33,715.74	-$676.79	-0.9%
AVG.USE	823	288,050	$39,274.02	$20,284.48	$18,989.54	$38,902.43	$20,284.48	$18,617.95	-$371.59	-0.9%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE 350			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	75	26,250	$4,242.26	$1,848.53	$2,393.73	$4,208.40	$1,848.53	$2,359.87	-$33.86	-0.8%
20	100	35,000	$5,577.32	$2,464.70	$3,112.62	$5,532.17	$2,464.70	$3,067.47	-$45.15	-0.8%
30	230	80,500	$12,519.65	$5,668.81	$6,850.84	$12,415.80	$5,668.81	$6,746.99	-$103.85	-0.8%
40	248	86,800	$13,480.89	$6,112.46	$7,368.43	$13,368.92	$6,112.46	$7,256.46	-$111.97	-0.8%
50	372	130,200	$20,102.80	$9,168.68	$10,934.12	$19,934.84	$9,168.68	$10,766.16	-$167.96	-0.8%
60	499	174,650	$26,884.91	$12,298.85	$14,586.06	$26,659.62	$12,298.85	$14,360.77	-$225.29	-0.8%
70	738	258,300	$39,648.12	$18,189.49	$21,458.63	$39,314.91	$18,189.49	$21,125.42	-$333.21	-0.8%
80	1,332	466,200	$71,369.20	$32,829.80	$38,539.40	$70,767.80	$32,829.80	$37,938.00	-$601.40	-0.8%
90	1,738	608,300	$93,050.62	$42,836.49	$50,214.13	$92,265.91	$42,836.49	$49,429.42	-$784.71	-0.8%
AVG.USE	914	319,900	$49,046.96	$22,527.36	$26,519.60	$48,634.29	$22,527.36	$26,106.93	-$412.67	-0.8%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION	(summer)		$14.83	PER KVA
DISTRIBUTION	(winter)		$8.86	
TRANSITION	(summer)		$2.73	
TRANSITION	(winter)		$2.73	
TRANSMISSION	(summer)		$7.37	
TRANSMISSION	(winter)		$7.37	

		PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER			$237.07	PER BILL
DISTRIBUTION	(summer)		$14.83	PER KVA
DISTRIBUTION	(winter)		$8.86	
TRANSITION	(summer)		$2.73	
TRANSITION	(winter)		$2.73	
TRANSMISSION	(summer)		$7.37	
TRANSMISSION	(winter)		$7.37	

		PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	78	35,100	$4,571.33	$2,471.74	$2,099.59	$4,526.05	$2,471.74	$2,054.31	-$45.28	-1.0%
20	131	58,950	$7,516.41	$4,151.26	$3,365.15	$7,440.37	$4,151.26	$3,289.11	-$76.04	-1.0%
30	223	100,350	$12,628.63	$7,066.65	$5,561.98	$12,499.17	$7,066.65	$5,432.52	-$129.46	-1.0%
40	246	110,700	$13,906.67	$7,795.49	$6,111.18	$13,763.87	$7,795.49	$5,968.38	-$142.80	-1.0%
50	339	152,550	$19,074.45	$10,742.57	$8,331.88	$18,877.66	$10,742.57	$8,135.09	-$196.79	-1.0%
60	448	201,600	$25,131.31	$14,196.67	$10,934.64	$24,871.24	$14,196.67	$10,674.57	-$260.07	-1.0%
70	553	248,850	$30,965.90	$17,524.02	$13,441.88	$30,644.88	$17,524.02	$13,120.86	-$321.02	-1.0%
80	1,193	536,850	$66,529.10	$37,804.98	$28,724.12	$65,836.56	$37,804.98	$28,031.58	-$692.54	-1.0%
90	1,499	674,550	$83,532.75	$47,501.81	$36,030.94	$82,662.58	$47,501.81	$35,160.77	-$870.17	-1.0%
AVG.USE	823	370,350	$45,969.13	$26,080.05	$19,889.08	$45,491.37	$26,080.05	$19,411.32	-$477.76	-1.0%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER	$237.07	PER BILL
DISTRIBUTION (summer)	$14.83	PER KVA
DISTRIBUTION (winter)	$8.86	
TRANSITION (summer)	$2.73	
TRANSITION (winter)	$2.73	
TRANSMISSION (summer)	$7.37	
TRANSMISSION (winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER	$237.07	PER BILL
DISTRIBUTION (summer)	$14.83	PER KVA
DISTRIBUTION (winter)	$8.86	
TRANSITION (summer)	$2.73	
TRANSITION (winter)	$2.73	
TRANSMISSION (summer)	$7.37	
TRANSMISSION (winter)	$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	75	33,750	$4,852.39	$2,376.68	$2,475.71	$4,808.85	$2,376.68	$2,432.17	-$43.54	-0.9%
20	100	45,000	$6,390.82	$3,168.90	$3,221.92	$6,332.77	$3,168.90	$3,163.87	-$58.05	-0.9%
30	230	103,500	$14,390.70	$7,288.47	$7,102.23	$14,257.18	$7,288.47	$6,968.71	-$133.52	-0.9%
40	248	111,600	$15,498.37	$7,858.87	$7,639.50	$15,354.40	$7,858.87	$7,495.53	-$143.97	-0.9%
50	372	167,400	$23,129.02	$11,788.31	$11,340.71	$22,913.08	$11,788.31	$11,124.77	-$215.94	-0.9%
60	499	224,550	$30,944.28	$15,812.81	$15,131.47	$30,654.61	$15,812.81	$14,841.80	-$289.67	-0.9%
70	738	332,100	$45,651.74	$23,386.48	$22,265.26	$45,223.33	$23,386.48	$21,836.85	-$428.41	-0.9%
80	1,332	599,400	$82,205.02	$42,209.75	$39,995.27	$81,431.80	$42,209.75	$39,222.05	-$773.22	-0.9%
90	1,738	782,100	$107,189.24	$55,075.48	$52,113.76	$106,180.33	$55,075.48	$51,104.85	-$1,008.91	-0.9%
AVG.USE	914	411,300	$56,482.35	$28,963.75	$27,518.60	$55,951.77	$28,963.75	$26,988.02	-$530.58	-0.9%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	
	PEAK	OFF-PEAK	
	42.82%	57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	
	PEAK	OFF-PEAK	
	33.82%	66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE	500		Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	78	39,000	$4,888.60	$2,746.38	$2,142.22	$4,838.29	$2,746.38	$2,091.91	-$50.31	-1.0%
20	131	65,500	$8,049.26	$4,612.51	$3,436.75	$7,964.76	$4,612.51	$3,352.25	-$84.50	-1.0%
30	223	111,500	$13,535.68	$7,851.83	$5,683.85	$13,391.84	$7,851.83	$5,540.01	-$143.84	-1.1%
40	246	123,000	$14,907.28	$8,661.66	$6,245.62	$14,748.61	$8,661.66	$6,086.95	-$158.67	-1.1%
50	339	169,500	$20,453.34	$11,936.19	$8,517.15	$20,234.68	$11,936.19	$8,298.49	-$218.66	-1.1%
60	448	224,000	$26,953.55	$15,774.08	$11,179.47	$26,664.59	$15,774.08	$10,890.51	-$288.96	-1.1%
70	553	276,500	$33,215.23	$19,471.13	$13,744.10	$32,858.54	$19,471.13	$13,387.41	-$356.69	-1.1%
80	1,193	596,500	$71,381.63	$42,005.53	$29,376.10	$70,612.14	$42,005.53	$28,606.61	-$769.49	-1.1%
90	1,499	749,500	$89,629.94	$52,779.79	$36,850.15	$88,663.08	$52,779.79	$35,883.29	-$966.86	-1.1%
AVG.USE	823	411,500	$49,316.68	$28,977.83	$20,338.85	$48,785.84	$28,977.83	$19,808.01	-$530.84	-1.1%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

		PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION	(summer)	$14.83	PER KVA
DISTRIBUTION	(winter)	$8.86	
TRANSITION	(summer)	$2.73	
TRANSITION	(winter)	$2.73	
TRANSMISSION	(summer)	$7.37	
TRANSMISSION	(winter)	$7.37	

		PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION	(summer)	0.217	0.217	CENTS/KWH
TRANSITION	(winter)	0.217	0.217	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.002	-0.002	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 - SEMA

HOURS USE	500		Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	75	37,500	$5,157.45	$2,640.75	$2,516.70	$5,109.07	$2,640.75	$2,468.32	-$48.38	-0.9%
20	100	50,000	$6,797.57	$3,521.00	$3,276.57	$6,733.07	$3,521.00	$3,212.07	-$64.50	-0.9%
30	230	115,000	$15,326.22	$8,098.30	$7,227.92	$15,177.87	$8,098.30	$7,079.57	-$148.35	-1.0%
40	248	124,000	$16,507.11	$8,732.08	$7,775.03	$16,347.15	$8,732.08	$7,615.07	-$159.96	-1.0%
50	372	186,000	$24,642.13	$13,098.12	$11,544.01	$24,402.19	$13,098.12	$11,304.07	-$239.94	-1.0%
60	499	249,500	$32,973.97	$17,569.79	$15,404.18	$32,652.11	$17,569.79	$15,082.32	-$321.86	-1.0%
70	738	369,000	$48,653.56	$25,984.98	$22,668.58	$48,177.55	$25,984.98	$22,192.57	-$476.01	-1.0%
80	1,332	666,000	$87,622.93	$46,899.72	$40,723.21	$86,763.79	$46,899.72	$39,864.07	-$859.14	-1.0%
90	1,738	869,000	$114,258.56	$61,194.98	$53,063.58	$113,137.55	$61,194.98	$51,942.57	-$1,121.01	-1.0%
AVG.USE	914	457,000	$60,200.04	$32,181.94	$28,018.10	$59,610.51	$32,181.94	$27,428.57	-$589.53	-1.0%

Current

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	

	PEAK 42.82%	OFF-PEAK 57.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3

DELIVERY SERVICES:

CUSTOMER		$237.07	PER BILL
DISTRIBUTION (summer)		$14.83	PER KVA
DISTRIBUTION (winter)		$8.86	
TRANSITION (summer)		$2.73	
TRANSITION (winter)		$2.73	
TRANSMISSION (summer)		$7.37	
TRANSMISSION (winter)		$7.37	

	PEAK 33.82%	OFF-PEAK 66.18%	
TRANSITION (summer)	0.217	0.217	CENTS/KWH
TRANSITION (winter)	0.217	0.217	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.002	-0.002	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 350 CUM % BILLS	WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	27	9,450	$1,355.86	$665.47	$690.39	$1,343.67	$665.47	$678.20	-$12.19	-0.9%
20	48	16,800	$2,388.82	$1,183.06	$1,205.76	$2,367.15	$1,183.06	$1,184.09	-$21.67	-0.9%
30	92	32,200	$4,553.11	$2,267.52	$2,285.59	$4,511.57	$2,267.52	$2,244.05	-$41.54	-0.9%
40	99	34,650	$4,897.43	$2,440.05	$2,457.38	$4,852.73	$2,440.05	$2,412.68	-$44.70	-0.9%
50	160	56,000	$7,984.78	$3,943.52	$4,041.26	$7,912.54	$3,943.52	$3,969.02	-$72.24	-0.9%
60	214	74,900	$10,640.96	$5,274.46	$5,366.50	$10,544.34	$5,274.46	$5,269.88	-$96.62	-0.9%
70	302	105,700	$15,021.59	$7,443.39	$7,578.20	$14,885.24	$7,443.39	$7,441.85	-$136.35	-0.9%
80	350	122,500	$17,382.65	$8,626.45	$8,756.20	$17,224.62	$8,626.45	$8,598.17	-$158.03	-0.9%
90	433	151,550	$21,465.29	$10,672.15	$10,793.14	$21,269.79	$10,672.15	$10,597.64	-$195.50	-0.9%
AVG.USE	238	83,300	$11,821.49	$5,865.99	$5,955.50	$11,714.03	$5,865.99	$5,848.04	-$107.46	-0.9%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150		$27.77	PER BILL
	150<KW<=300		$114.62	
	300<KW<=100		$166.67	
	KW > 1000		$374.57	
DISTRIBUTION (summer)			$19.88	PER KVA
DISTRIBUTION (winter)			$11.43	
TRANSITION (summer)			$1.66	
TRANSITION (winter)			$1.66	
TRANSMISSION (summer)			$7.08	
TRANSMISSION (winter)			$7.08	
	PEAK 45.51%	OFF-PEAK 54.49%		
TRANSITION (summer)	0.376	0.376	CENTS/KWH	
TRANSITION (winter)	0.376	0.376	" "	
DEMAND-SIDE MGT	0.250	0.250	" "	
RENEWABLE ENERGY	0.050	0.050	" "	
TRANSITION RATE ADJ	-0.005	-0.005	" "	
DEFAULT SERV ADJ	0.000	0.000	" "	
DIST ADJ		0.578	" "	

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150		$27.77	PER BILL
	150<KW<=300		$114.62	
	300<KW<=100		$166.67	
	KW > 1000		$374.57	
DISTRIBUTION (summer)			$19.88	PER KVA
DISTRIBUTION (winter)			$11.43	
TRANSITION (summer)			$1.66	
TRANSITION (winter)			$1.66	
TRANSMISSION (summer)			$7.08	
TRANSMISSION (winter)			$7.08	
	PEAK 45.51%	OFF-PEAK 54.49%		
TRANSITION (summer)	0.376	0.376	CENTS/KWH	
TRANSITION (winter)	0.376	0.376	" "	
DEMAND-SIDE MGT	0.250	0.250	" "	
RENEWABLE ENERGY	0.050	0.050	" "	
TRANSITION RATE ADJ	-0.005	-0.005	" "	
DEFAULT SERV ADJ	0.000	0.000	" "	
DIST ADJ	0.449	0.449	" "	

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 350			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	17	5,950	$1,007.63	$419.00	$588.63	$999.95	$419.00	$580.95	-$7.68	-0.8%
20	44	15,400	$2,563.87	$1,084.47	$1,479.40	$2,544.00	$1,084.47	$1,459.53	-$19.87	-0.8%
30	86	30,100	$4,984.68	$2,119.64	$2,865.04	$4,945.85	$2,119.64	$2,826.21	-$38.83	-0.8%
40	94	32,900	$5,445.79	$2,316.82	$3,128.97	$5,403.35	$2,316.82	$3,086.53	-$42.44	-0.8%
50	153	53,550	$8,933.31	$3,770.99	$5,162.32	$8,864.23	$3,770.99	$5,093.24	-$69.08	-0.8%
60	243	85,050	$14,120.77	$5,989.22	$8,131.55	$14,011.06	$5,989.22	$8,021.84	-$109.71	-0.8%
70	338	118,300	$19,648.49	$8,330.69	$11,317.80	$19,495.88	$8,330.69	$11,165.19	-$152.61	-0.8%
80	358	125,300	$20,801.26	$8,823.63	$11,977.63	$20,639.62	$8,823.63	$11,815.99	-$161.64	-0.8%
90	547	191,450	$31,694.93	$13,481.91	$18,213.02	$31,447.96	$13,481.91	$17,966.05	-$246.97	-0.8%
AVG.USE	262	91,700	$15,215.90	$6,457.51	$8,758.39	$15,097.61	$6,457.51	$8,640.10	-$118.29	-0.8%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK	OFF-PEAK	
	37.67%	62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK	OFF-PEAK	
	37.67%	62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 400 CUM % BILLS	WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	27	10,800	$1,467.79	$760.54	$707.25	$1,453.86	$760.54	$693.32	-$13.93	-0.9%
20	48	19,200	$2,587.80	$1,352.06	$1,235.74	$2,563.03	$1,352.06	$1,210.97	-$24.77	-1.0%
30	92	36,800	$4,934.50	$2,591.46	$2,343.04	$4,887.03	$2,591.46	$2,295.57	-$47.47	-1.0%
40	99	39,600	$5,307.83	$2,788.63	$2,519.20	$5,256.75	$2,788.63	$2,468.12	-$51.08	-1.0%
50	160	64,000	$8,648.06	$4,506.88	$4,141.18	$8,565.50	$4,506.88	$4,058.62	-$82.56	-1.0%
60	214	85,600	$11,528.09	$6,027.95	$5,500.14	$11,417.67	$6,027.95	$5,389.72	-$110.42	-1.0%
70	302	120,800	$16,273.54	$8,506.74	$7,766.80	$16,117.71	$8,506.74	$7,610.97	-$155.83	-1.0%
80	350	140,000	$18,833.57	$9,858.80	$8,974.77	$18,652.97	$9,858.80	$8,794.17	-$180.60	-1.0%
90	433	173,200	$23,260.29	$12,196.74	$11,063.55	$23,036.86	$12,196.74	$10,840.12	-$223.43	-1.0%
AVG.USE	238	95,200	$12,808.11	$6,703.98	$6,104.13	$12,685.30	$6,703.98	$5,981.32	-$122.81	-1.0%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

		PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION	(summer)	0.376	0.376	CENTS/KWH
TRANSITION	(winter)	0.376	0.376	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.005	-0.005	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

		PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION	(summer)	0.376	0.376	CENTS/KWH
TRANSITION	(winter)	0.376	0.376	" "
DEMAND-SIDE MGT		0.250	0.250	" "
RENEWABLE ENERGY		0.050	0.050	" "
TRANSITION RATE ADJ		-0.005	-0.005	" "
DEFAULT SERV ADJ		0.000	0.000	" "
DIST ADJ		0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 400			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	17	6,800	$1,078.10	$478.86	$599.24	$1,069.33	$478.86	$590.47	-$8.77	-0.8%
20	44	17,600	$2,746.26	$1,239.39	$1,506.87	$2,723.56	$1,239.39	$1,484.17	-$22.70	-0.8%
30	86	34,400	$5,341.20	$2,422.45	$2,918.75	$5,296.82	$2,422.45	$2,874.37	-$44.38	-0.8%
40	94	37,600	$5,835.46	$2,647.79	$3,187.67	$5,786.96	$2,647.79	$3,139.17	-$48.50	-0.8%
50	153	61,200	$9,567.57	$4,309.70	$5,257.87	$9,488.62	$4,309.70	$5,178.92	-$78.95	-0.8%
60	243	97,200	$15,128.13	$6,844.82	$8,283.31	$15,002.74	$6,844.82	$8,157.92	-$125.39	-0.8%
70	338	135,200	$21,049.66	$9,520.78	$11,528.88	$20,875.25	$9,520.78	$11,354.47	-$174.41	-0.8%
80	358	143,200	$22,285.34	$10,084.14	$12,201.20	$22,100.61	$10,084.14	$12,016.47	-$184.73	-0.8%
90	547	218,800	$33,962.52	$15,407.90	$18,554.62	$33,680.27	$15,407.90	$18,272.37	-$282.25	-0.8%
AVG.USE	262	104,800	$16,302.03	$7,380.02	$8,922.01	$16,166.84	$7,380.02	$8,786.82	-$135.19	-0.8%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	WINTER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	27	12,150	$1,579.71	$855.60	$724.11	$1,564.04	$855.60	$708.44	-$15.67	-1.0%
20	48	21,600	$2,786.78	$1,521.07	$1,265.71	$2,758.92	$1,521.07	$1,237.85	-$27.86	-1.0%
30	92	41,400	$5,315.89	$2,915.39	$2,400.50	$5,262.48	$2,915.39	$2,347.09	-$53.41	-1.0%
40	99	44,550	$5,718.24	$3,137.21	$2,581.03	$5,660.77	$3,137.21	$2,523.56	-$57.47	-1.0%
50	160	72,000	$9,311.34	$5,070.24	$4,241.10	$9,218.46	$5,070.24	$4,148.22	-$92.88	-1.0%
60	214	96,300	$12,415.24	$6,781.45	$5,633.79	$12,291.01	$6,781.45	$5,509.56	-$124.23	-1.0%
70	302	135,900	$17,525.48	$9,570.08	$7,955.40	$17,350.17	$9,570.08	$7,780.09	-$175.31	-1.0%
80	350	157,500	$20,284.50	$11,091.15	$9,193.35	$20,081.32	$11,091.15	$8,990.17	-$203.18	-1.0%
90	433	194,850	$25,055.30	$13,721.34	$11,333.96	$24,803.94	$13,721.34	$11,082.60	-$251.36	-1.0%
AVG.USE	238	107,100	$13,794.74	$7,541.98	$6,252.76	$13,656.58	$7,541.98	$6,114.60	-$138.16	-1.0%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER		KW < 150	$27.77	PER BILL
		150<KW<=300	$114.62	
		300<KW<=100	$166.67	
		KW > 1000	$374.57	
DISTRIBUTION	(summer)		$19.88	PER KVA
DISTRIBUTION	(winter)		$11.43	
TRANSITION	(summer)		$1.66	
TRANSITION	(winter)		$1.66	
TRANSMISSION	(summer)		$7.08	
TRANSMISSION	(winter)		$7.08	

	PEAK 45.51%	OFF-PEAK 54.49%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

BOSTON EDISON COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE T-2 - SEMA

Hours Use 450			Current			Proposed			DIFFERENCE	
CUM % BILLS	SUMMER KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	17	7,650	$1,148.57	$538.71	$609.86	$1,138.70	$538.71	$599.99	-$9.87	-0.9%
20	44	19,800	$2,928.67	$1,394.32	$1,534.35	$2,903.13	$1,394.32	$1,508.81	-$25.54	-0.9%
30	86	38,700	$5,697.70	$2,725.25	$2,972.45	$5,647.78	$2,725.25	$2,922.53	-$49.92	-0.9%
40	94	42,300	$6,225.15	$2,978.77	$3,246.38	$6,170.58	$2,978.77	$3,191.81	-$54.57	-0.9%
50	153	68,850	$10,201.84	$4,848.42	$5,353.42	$10,113.02	$4,848.42	$5,264.60	-$88.82	-0.9%
60	243	109,350	$16,135.49	$7,700.43	$8,435.06	$15,994.43	$7,700.43	$8,294.00	-$141.06	-0.9%
70	338	152,100	$22,450.84	$10,710.88	$11,739.96	$22,254.63	$10,710.88	$11,543.75	-$196.21	-0.9%
80	358	161,100	$23,769.43	$11,344.66	$12,424.77	$23,561.61	$11,344.66	$12,216.95	-$207.82	-0.9%
90	547	246,150	$36,230.10	$17,333.88	$18,896.22	$35,912.57	$17,333.88	$18,578.69	-$317.53	-0.9%
AVG.USE	262	117,900	$17,388.15	$8,302.52	$9,085.63	$17,236.06	$8,302.52	$8,933.54	-$152.09	-0.9%

Current

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.578	0.578	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE T-2

DELIVERY SERVICES:

CUSTOMER	KW < 150	$27.77	PER BILL
	150<KW<=300	$114.62	
	300<KW<=100	$166.67	
	KW > 1000	$374.57	
DISTRIBUTION (summer)		$19.88	PER KVA
DISTRIBUTION (winter)		$11.43	
TRANSITION (summer)		$1.66	
TRANSITION (winter)		$1.66	
TRANSMISSION (summer)		$7.08	
TRANSMISSION (winter)		$7.08	

	PEAK 37.67%	OFF-PEAK 62.33%	
TRANSITION (summer)	0.376	0.376	CENTS/KWH
TRANSITION (winter)	0.376	0.376	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
TRANSITION RATE ADJ	-0.005	-0.005	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DIST ADJ	0.449	0.449	" "

SUPPLIER SERVICES:

DEFAULT SERVICE SEMA - FIXED	6.988	6.988	CENTS/KWH
DEAULT SERVI CE - ADDER	0.054	0.054	" "

COMMONWEALTH ELECTRIC TYPICAL BILL COMPARISONS AUGUST 2013 DELIVERY RATES						
					Proposed vs. Current Change in Total Bill	
Class	Rate	Load Fact	Avg Kw	Avg Kwh	Amount	%
Residential	Res Rate R-1 Annual			584	(0.75)	-0.7%
	Res Rate R-1 Seasonal Winter			141	(0.18)	-0.5%
	Res Rate R-1 Seasonal Summer			401	(0.52)	-0.5%
	Res Assist R-2 Annual			483	(0.48)	-0.7%
	Res Assist R-2 Seasonal Winter			313	(0.29)	-0.5%
	Res Assist R-2 Seasonal Summer			385	(0.36)	-0.5%
	Res Space Heating R-3			859	(1.10)	-0.7%
	Res Assist Spc Htg R-4			934	(0.97)	-0.8%
	Res Controlled Wtr Htg R-5			187	(0.24)	-0.8%
	Res TOU R-6			1,049	(1.35)	-0.7%
Small Comm.	General G-1 Annual	0.440	8	2,396	(3.09)	-0.7%
	General G-1 Annual	0.508	6	2,396	(3.09)	-0.7%
	General G-1 Annual	0.308	11	2,396	(3.09)	-0.7%
	General G-1 Seasonal Winter	0.300	3	539	(0.70)	-0.6%
	General G-1 Seasonal Summer	0.300	9	1,605	(2.07)	-0.6%
	General Power G-4	0.225	42	6,844	(8.83)	-0.8%
	General Power G-4	0.325	29	6,844	(8.83)	-0.8%
	General Power G-4	0.125	75	6,844	(8.83)	-0.7%
	Comm Space Heating G-5			1,563	(2.01)	-0.7%
	All Electric School G-6			88,287	(113.89)	-0.9%
	General TOU G-7 Annual	0.466	14	4,742	(6.12)	-0.8%
	General TOU G-7 Annual	0.666	10	4,742	(6.12)	-0.8%
	General TOU G-7 Annual	0.266	24	4,742	(6.12)	-0.7%
	General TOU G-7 Seasonal Winter	0.172	4	532	(0.68)	-0.6%
	General TOU G-7 Seasonal Summ	0.172	7	919	(1.19)	-0.6%
Lg Comm/Ind	Medium General G-2	0.528	272	101,737	(131.24)	-0.9%
	Medium General G-2	0.712	272	141,375	(182.37)	-0.9%
	Medium General G-2	0.312	272	61,951	(79.91)	-0.8%
	Large General G-3	0.586	1,285	488,724	(630.52)	-0.9%
	Large General G-3	0.721	1,285	676,334	(872.56)	-1.0%
	Large General G-3	0.321	1,285	301,114	(388.48)	-0.8%

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL RATE R-1

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		160	$33.98	$12.01	$21.97	$33.78	$12.01	$21.77	($0.20)	-0.6%
20		230	$47.21	$17.26	$29.95	$46.92	$17.26	$29.66	(0.29)	-0.6%
30		306	$61.59	$22.97	$38.62	$61.19	$22.97	$38.22	(0.40)	-0.6%
40		382	$75.95	$28.67	$47.28	$75.46	$28.67	$46.79	(0.49)	-0.6%
50		464	$91.46	$34.83	$56.63	$90.86	$34.83	$56.03	(0.60)	-0.7%
60		555	$108.67	$41.66	$67.01	$107.95	$41.66	$66.29	(0.72)	-0.7%
70		660	$128.52	$49.54	$78.98	$127.67	$49.54	$78.13	(0.85)	-0.7%
80		793	$153.66	$59.52	$94.14	$152.64	$59.52	$93.12	(1.02)	-0.7%
90		997	$192.23	$74.83	$117.40	$190.94	$74.83	$116.11	(1.29)	-0.7%
AVG.USE		584	$114.15	$43.84	$70.31	$113.40	$43.84	$69.56	(0.75)	-0.7%

Current

RESIDENTIAL RATE R-1 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	4.961	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.863	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.355	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RESIDENTIAL RATE R-1 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	4.961	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.863	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.226	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SEASONAL RATE R-1

CUM % BILLS	KW	WINTER KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		14	$7.11	$1.05	$6.06	$7.09	$1.05	$6.04	($0.02)	-0.3%
20		23	$9.29	$1.73	$7.56	$9.26	$1.73	$7.53	(0.03)	-0.3%
30		34	$11.94	$2.55	$9.39	$11.89	$2.55	$9.34	(0.05)	-0.4%
40		46	$14.83	$3.45	$11.38	$14.77	$3.45	$11.32	(0.06)	-0.4%
50		65	$19.42	$4.88	$14.54	$19.34	$4.88	$14.46	(0.08)	-0.4%
60		90	$25.46	$6.76	$18.70	$25.35	$6.76	$18.59	(0.11)	-0.4%
70		125	$33.91	$9.38	$24.53	$33.75	$9.38	$24.37	(0.16)	-0.5%
80		179	$46.95	$13.44	$33.51	$46.72	$13.44	$33.28	(0.23)	-0.5%
90		287	$73.02	$21.54	$51.48	$72.65	$21.54	$51.11	(0.37)	-0.5%
AVG.USE		141	$37.77	$10.58	$27.19	$37.59	$10.58	$27.01	(0.18)	-0.5%

Current

RESIDENTIAL RATE R-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.355	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RESIDENTIAL RATE R-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.226	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SEASONAL RATE R-1

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		80	$23.04	$6.00	$17.04	$22.94	$6.00	$16.94	($0.10)	-0.4%
20		123	$33.42	$9.23	$24.19	$33.27	$9.23	$24.04	(0.15)	-0.4%
30		163	$43.08	$12.23	$30.85	$42.87	$12.23	$30.64	(0.21)	-0.5%
40		208	$53.95	$15.61	$38.34	$53.68	$15.61	$38.07	(0.27)	-0.5%
50		261	$66.75	$19.59	$47.16	$66.41	$19.59	$46.82	(0.34)	-0.5%
60		328	$82.92	$24.62	$58.30	$82.50	$24.62	$57.88	(0.42)	-0.5%
70		417	$104.41	$31.30	$73.11	$103.87	$31.30	$72.57	(0.54)	-0.5%
80		543	$134.83	$40.76	$94.07	$134.13	$40.76	$93.37	(0.70)	-0.5%
90		739	$182.15	$55.47	$126.68	$181.20	$55.47	$125.73	(0.95)	-0.5%
AVG.USE		401	$100.55	$30.10	$70.45	$100.03	$30.10	$69.93	(0.52)	-0.5%

Current

RESIDENTIAL RATE R-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.355	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RESIDENTIAL RATE R-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.226	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL ASSISTANCE RATE R-2 (R1)

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		146	$23.26	$8.49	$14.77	$23.12	$8.49	$14.63	($0.14)	-0.6%
20		194	$29.97	$11.29	$18.68	$29.78	$11.29	$18.49	(0.19)	-0.6%
30		243	$36.81	$14.14	$22.67	$36.56	$14.14	$22.42	(0.25)	-0.7%
40		293	$43.78	$17.04	$26.74	$43.48	$17.04	$26.44	(0.30)	-0.7%
50		350	$51.73	$20.36	$31.37	$51.38	$20.36	$31.02	(0.35)	-0.7%
60		416	$60.95	$24.20	$36.75	$60.53	$24.20	$36.33	(0.42)	-0.7%
70		497	$72.25	$28.91	$43.34	$71.75	$28.91	$42.84	(0.50)	-0.7%
80		608	$87.74	$35.37	$52.37	$87.13	$35.37	$51.76	(0.61)	-0.7%
90		785	$112.44	$45.66	$66.78	$111.65	$45.66	$65.99	(0.79)	-0.7%
AVG.USE		483	$70.30	$28.10	$42.20	$69.82	$28.10	$41.72	(0.48)	-0.7%

Current

RESIDENTIAL ASSISTANCE RATE R-2 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	4.961	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.863	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.455	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 22.5%

Proposed

RESIDENTIAL ASSISTANCE RATE R-2 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	4.961	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.863	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.326	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 22.5%

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL ASSISTANCE SEASONAL RATE R-2 (R1S)

CUM % BILLS	KW	WINTER KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		17	$5.60	$0.93	$4.67	$5.58	$0.93	$4.65	($0.02)	-0.4%
20		42	$9.84	$2.30	$7.54	$9.80	$2.30	$7.50	(0.04)	-0.4%
30		91	$18.14	$4.98	$13.16	$18.05	$4.98	$13.07	(0.09)	-0.5%
40		155	$28.98	$8.48	$20.50	$28.84	$8.48	$20.36	(0.14)	-0.5%
50		171	$31.70	$9.36	$22.34	$31.54	$9.36	$22.18	(0.16)	-0.5%
60		267	$47.96	$14.61	$33.35	$47.71	$14.61	$33.10	(0.25)	-0.5%
70		344	$61.01	$18.82	$42.19	$60.68	$18.82	$41.86	(0.33)	-0.5%
80		395	$69.65	$21.61	$48.04	$69.28	$21.61	$47.67	(0.37)	-0.5%
90		624	$108.45	$34.14	$74.31	$107.86	$34.14	$73.72	(0.59)	-0.5%
AVG.USE		313	$55.76	$17.13	$38.63	$55.47	$17.13	$38.34	(0.29)	-0.5%

Current

RESIDENTIAL ASSISTANCE RATE R-2 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.455	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 27.1%

Proposed

RESIDENTIAL ASSISTANCE RATE R-2 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.326	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT 27.1%

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL ASSISTANCE SEASONAL RATE R-2 (R1S)

			Current			Proposed			DIFFERENCE	
CUM % BILLS	KW	SUMMER KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		122	$23.40	$6.68	$16.72	$23.28	$6.68	$16.60	($0.12)	-0.5%
20		172	$31.86	$9.41	$22.45	$31.70	$9.41	$22.29	(0.16)	-0.5%
30		273	$48.98	$14.94	$34.04	$48.72	$14.94	$33.78	(0.26)	-0.5%
40		298	$53.22	$16.31	$36.91	$52.94	$16.31	$36.63	(0.28)	-0.5%
50		342	$60.67	$18.71	$41.96	$60.35	$18.71	$41.64	(0.32)	-0.5%
60		326	$57.96	$17.84	$40.12	$57.65	$17.84	$39.81	(0.31)	-0.5%
70		390	$68.80	$21.34	$47.46	$68.44	$21.34	$47.10	(0.36)	-0.5%
80		516	$90.15	$28.23	$61.92	$89.66	$28.23	$61.43	(0.49)	-0.5%
90		756	$130.83	$41.37	$89.46	$130.11	$41.37	$88.74	(0.72)	-0.6%
AVG.USE		385	$67.96	$21.07	$46.89	$67.60	$21.07	$46.53	(0.36)	-0.5%

Current

RESIDENTIAL ASSISTANCE RATE R-2 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.455	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 27.1%

Proposed

RESIDENTIAL ASSISTANCE RATE R-2 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$3.73	PER BILL
DISTRIBUTION	ALL KWH @	8.383	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	3.678	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.326	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT 27.1%

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SPACE HEATING RATE R-3

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		215	$46.26	$16.14	$30.12	$45.98	$16.14	$29.84	($0.28)	-0.6%
20		328	$65.30	$24.62	$40.68	$64.88	$24.62	$40.26	(0.42)	-0.6%
30		451	$86.03	$33.85	$52.18	$85.44	$33.85	$51.59	(0.59)	-0.7%
40		568	$105.74	$42.63	$63.11	$105.01	$42.63	$62.38	(0.73)	-0.7%
50		690	$126.30	$51.79	$74.51	$125.41	$51.79	$73.62	(0.89)	-0.7%
60		824	$148.88	$61.85	$87.03	$147.82	$61.85	$85.97	(1.06)	-0.7%
70		982	$175.51	$73.71	$101.80	$174.24	$73.71	$100.53	(1.27)	-0.7%
80		1,184	$209.54	$88.87	$120.67	$208.02	$88.87	$119.15	(1.52)	-0.7%
90		1,489	$260.94	$111.76	$149.18	$259.02	$111.76	$147.26	(1.92)	-0.7%
AVG.USE		859	$154.78	$64.48	$90.30	$153.68	$64.48	$89.20	(1.10)	-0.7%

Current

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

CUSTOMER		$10.03	PER BILL
DISTRIBUTION	ALL KWH @	3.065	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.703	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.355	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

CUSTOMER		$10.03	PER BILL
DISTRIBUTION	ALL KWH @	3.065	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.703	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	1.226	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RES ASSISTANCE SPACE HEATING RATE R-4 (R3)

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		349	$52.76	$21.04	$31.72	$52.40	$21.04	$31.36	($0.36)	-0.7%
20		455	$66.33	$27.42	$38.91	$65.86	$27.42	$38.44	(0.47)	-0.7%
30		551	$78.63	$33.21	$45.42	$78.06	$33.21	$44.85	(0.57)	-0.7%
40		639	$89.90	$38.51	$51.39	$89.23	$38.51	$50.72	(0.67)	-0.7%
50		752	$104.38	$45.33	$59.05	$103.60	$45.33	$58.27	(0.78)	-0.7%
60		877	$120.39	$52.86	$67.53	$119.48	$52.86	$66.62	(0.91)	-0.8%
70		1,036	$140.75	$62.44	$78.31	$139.68	$62.44	$77.24	(1.07)	-0.8%
80		1,234	$166.12	$74.38	$91.74	$164.84	$74.38	$90.46	(1.28)	-0.8%
90		1,523	$203.13	$91.80	$111.33	$201.56	$91.80	$109.76	(1.57)	-0.8%
AVG.USE		934	$127.69	$56.30	$71.39	$126.72	$56.30	$70.42	(0.97)	-0.8%

Current

RES ASSISTANCE SPACE HEATING RATE R-4

DELIVERY SERVICES:

CUSTOMER		$10.03	PER BILL
DISTRIBUTION	ALL KWH @	3.065	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.703	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.455	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT 19.7%

Proposed

RES ASSISTANCE SPACE HEATING RATE R-4

DELIVERY SERVICES:

CUSTOMER		$10.03	PER BILL
DISTRIBUTION	ALL KWH @	3.065	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.703	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.326	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

LOW INCOME DISCOUNT 19.7%

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
CONTROLLED WATER HEATING RATE R-5

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		43	$7.31	$3.23	$4.08	$7.25	$3.23	$4.02	($0.06)	-0.8%
20		69	$11.73	$5.18	$6.55	$11.64	$5.18	$6.46	(0.09)	-0.8%
30		93	$15.80	$6.98	$8.82	$15.68	$6.98	$8.70	(0.12)	-0.8%
40		118	$20.05	$8.86	$11.19	$19.90	$8.86	$11.04	(0.15)	-0.7%
50		147	$24.97	$11.03	$13.94	$24.78	$11.03	$13.75	(0.19)	-0.8%
60		178	$30.25	$13.36	$16.89	$30.02	$13.36	$16.66	(0.23)	-0.8%
70		214	$36.36	$16.06	$20.30	$36.08	$16.06	$20.02	(0.28)	-0.8%
80		261	$44.35	$19.59	$24.76	$44.01	$19.59	$24.42	(0.34)	-0.8%
90		331	$56.24	$24.84	$31.40	$55.81	$24.84	$30.97	(0.43)	-0.8%
AVG.USE		187	$31.78	$14.04	$17.74	$31.54	$14.04	$17.50	(0.24)	-0.8%

Current

CONT WATER HEATING RATE R-5

DELIVERY SERVICES:

CUSTOMER		$0.00	PER BILL
DISTRIBUTION	ALL KWH @	3.188	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.722	" "
TRANS RATE ADJ	" "	-0.001	" "
DISTRIBUTION ADJ	" "	1.355	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

CONT WATER HEATING RATE R-5

DELIVERY SERVICES:

CUSTOMER		$0.00	PER BILL
DISTRIBUTION	ALL KWH @	3.188	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.722	" "
TRANS RATE ADJ	" "	-0.001	" "
DISTRIBUTION ADJ	" "	1.226	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL TOU RATE R-6

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		296	$57.80	$22.22	$35.58	$57.42	$22.22	$35.20	($0.38)	-0.7%
20		405	$76.38	$30.40	$45.98	$75.86	$30.40	$45.46	(0.52)	-0.7%
30		493	$91.38	$37.00	$54.38	$90.74	$37.00	$53.74	(0.64)	-0.7%
40		566	$103.83	$42.48	$61.35	$103.10	$42.48	$60.62	(0.73)	-0.7%
50		653	$118.66	$49.01	$69.65	$117.82	$49.01	$68.81	(0.84)	-0.7%
60		813	$145.94	$61.02	$84.92	$144.89	$61.02	$83.87	(1.05)	-0.7%
70		974	$173.40	$73.11	$100.29	$172.14	$73.11	$99.03	(1.26)	-0.7%
80		1,295	$228.12	$97.20	$130.92	$226.45	$97.20	$129.25	(1.67)	-0.7%
90		2,096	$364.70	$157.33	$207.37	$361.99	$157.33	$204.66	(2.71)	-0.7%
AVG.USE		1,049	$186.18	$78.74	$107.44	$184.83	$78.74	$106.09	(1.35)	-0.7%

Current

RESIDENTIAL TOU RATE R-6

DELIVERY SERVICES:

	PEAK 15.62%	OFF-PEAK 84.38%	
CUSTOMER		$7.33	PER BILL
DISTRIBUTION	14.606	1.159	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.703	1.703	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	1.355	1.355	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RESIDENTIAL TOU RATE R-6

DELIVERY SERVICES:

	PEAK 15.62%	OFF-PEAK 84.38%	
CUSTOMER		$7.33	PER BILL
DISTRIBUTION	14.606	1.159	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.703	1.703	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	1.226	1.226	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.452	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1

LF = CUM % BILLS	AVERAGE 0.408 MONTHLY KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	13	$7.79	$0.97	$6.82	$7.77	$0.97	$6.80	($0.02)	-0.3%
20	0	82	$19.69	$6.06	$13.63	$19.58	$6.06	$13.52	(0.11)	-0.6%
30	1	186	$37.75	$13.78	$23.97	$37.51	$13.78	$23.73	(0.24)	-0.6%
40	1	335	$63.76	$24.91	$38.85	$63.32	$24.91	$38.41	(0.44)	-0.7%
50	2	525	$96.68	$38.99	$57.69	$96.00	$38.99	$57.01	(0.68)	-0.7%
60	3	826	$148.89	$61.33	$87.56	$147.83	$61.33	$86.50	(1.06)	-0.7%
70	4	1,275	$226.80	$94.66	$132.14	$225.16	$94.66	$130.50	(1.64)	-0.7%
80	8	2,351	$412.20	$174.61	$237.59	$409.17	$174.61	$234.56	(3.03)	-0.7%
90	17	4,950	$821.28	$367.60	$453.68	$814.89	$367.60	$447.29	(6.39)	-0.8%
AVG.USE	8	2,396	$418.64	$177.93	$240.71	$415.55	$177.93	$237.62	(3.09)	-0.7%

Current

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1

LF = CUM % BILLS	HIGH 0.508 MONTHLY KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	13	$7.79	$0.97	$6.82	$7.77	$0.97	$6.80	($0.02)	-0.3%
20	0	82	$19.69	$6.06	$13.63	$19.58	$6.06	$13.52	(0.11)	-0.6%
30	1	186	$37.75	$13.78	$23.97	$37.51	$13.78	$23.73	(0.24)	-0.6%
40	1	335	$63.76	$24.91	$38.85	$63.32	$24.91	$38.41	(0.44)	-0.7%
50	1	525	$96.68	$38.99	$57.69	$96.00	$38.99	$57.01	(0.68)	-0.7%
60	2	826	$148.89	$61.33	$87.56	$147.83	$61.33	$86.50	(1.06)	-0.7%
70	3	1,275	$226.80	$94.66	$132.14	$225.16	$94.66	$130.50	(1.64)	-0.7%
80	6	2,351	$412.20	$174.61	$237.59	$409.17	$174.61	$234.56	(3.03)	-0.7%
90	13	4,950	$801.84	$367.60	$434.24	$795.45	$367.60	$427.85	(6.39)	-0.8%
AVG.USE	6	2,396	$418.64	$177.93	$240.71	$415.55	$177.93	$237.62	(3.09)	-0.7%

Current

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1

LF = CUM % BILLS	LOW 0.308 MONTHLY KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	13	$7.79	$0.97	$6.82	$7.77	$0.97	$6.80	($0.02)	-0.3%
20	0	82	$19.69	$6.06	$13.63	$19.58	$6.06	$13.52	(0.11)	-0.6%
30	1	186	$37.75	$13.78	$23.97	$37.51	$13.78	$23.73	(0.24)	-0.6%
40	1	335	$63.76	$24.91	$38.85	$63.32	$24.91	$38.41	(0.44)	-0.7%
50	2	525	$96.68	$38.99	$57.69	$96.00	$38.99	$57.01	(0.68)	-0.7%
60	4	826	$148.89	$61.33	$87.56	$147.83	$61.33	$86.50	(1.06)	-0.7%
70	6	1,275	$226.80	$94.66	$132.14	$225.16	$94.66	$130.50	(1.64)	-0.7%
80	10	2,351	$412.20	$174.61	$237.59	$409.17	$174.61	$234.56	(3.03)	-0.7%
90	22	4,950	$845.58	$367.60	$477.98	$839.19	$367.60	$471.59	(6.39)	-0.8%
AVG.USE	11	2,396	$423.50	$177.93	$245.57	$420.41	$177.93	$242.48	(3.09)	-0.7%

Current

GENERAL RATE G-1

DELIVERY SERVICES:

	FIRST 10	OVER 10	
CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1

DELIVERY SERVICES:

	FIRST 10	OVER 10	
CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)	$0.00	$4.86	PER KW
TRANSMISSION	$0.00	$0.00	
	< 2300 KWH	>2300 KWH	
DISTRIBUTION (ENERGY)	4.128	1.201	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	1.895	1.895	" "
TRANS RATE ADJ	0.004	0.004	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (SEASONAL)

LF = CUM % BILLS	AVERAGE 0.248 WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	0	$5.53	$0.00	$5.53	$5.53	$0.00	$5.53	$0.00	0.0%
20	0	0	$5.53	$0.00	$5.53	$5.53	$0.00	$5.53	0.00	0.0%
30	0	0	$5.53	$0.00	$5.53	$5.53	$0.00	$5.53	0.00	0.0%
40	0	0	$5.53	$0.00	$5.53	$5.53	$0.00	$5.53	0.00	0.0%
50	0	7	$7.03	$0.52	$6.51	$7.02	$0.52	$6.50	(0.01)	-0.1%
60	0	47	$15.61	$3.49	$12.12	$15.55	$3.49	$12.06	(0.06)	-0.4%
70	1	140	$35.55	$10.40	$25.15	$35.37	$10.40	$24.97	(0.18)	-0.5%
80	2	377	$86.36	$28.00	$58.36	$85.88	$28.00	$57.88	(0.48)	-0.6%
90	6	1,009	$221.86	$74.93	$146.93	$220.56	$74.93	$145.63	(1.30)	-0.6%
AVG.USE	3	539	$121.10	$40.03	$81.07	$120.40	$40.03	$80.37	(0.70)	-0.6%

Current

GENERAL RATE G-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.31	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 1800 KWH	>1800 KWH	
DISTRIBUTION (ENERGY)	7.657	2.472	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	2.451	2.451	" "
TRANS RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.31	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 1800 KWH	>1800 KWH	
DISTRIBUTION (ENERGY)	7.657	2.472	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	2.451	2.451	" "
TRANS RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (SEASONAL)

LF = CUM % BILLS	AVERAGE 0.248 SUMMER KW	KWH	TOTAL	Current SUPPLIER	DELIVERY	TOTAL	Proposed SUPPLIER	DELIVERY	DIFFERENCE AMOUNT	%
10	0	0	$5.53	$0.00	$5.53	$5.53	$0.00	$5.53	$0.00	0.0%
20	0	24	$10.67	$1.78	$8.89	$10.64	$1.78	$8.86	(0.03)	-0.3%
30	1	102	$27.39	$7.57	$19.82	$27.26	$7.57	$19.69	(0.13)	-0.5%
40	1	238	$56.55	$17.67	$38.88	$56.25	$17.67	$38.58	(0.30)	-0.5%
50	2	446	$101.15	$33.12	$68.03	$100.58	$33.12	$67.46	(0.57)	-0.6%
60	4	755	$167.41	$56.07	$111.34	$166.43	$56.07	$110.36	(0.98)	-0.6%
70	7	1,256	$274.82	$93.27	$181.55	$273.20	$93.27	$179.93	(1.62)	-0.6%
80	13	2,265	$479.97	$168.20	$311.77	$477.05	$168.20	$308.85	(2.92)	-0.6%
90	28	5,062	$999.26	$375.90	$623.36	$992.73	$375.90	$616.83	(6.53)	-0.7%
AVG.USE	9	1,605	$349.64	$119.19	$230.45	$347.57	$119.19	$228.38	(2.07)	-0.6%

Current

GENERAL RATE G-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.31	PER KW
TRANSMISSION	$0.00	$0.00	PER KW
	< 1800 KWH	>1800 KWH	
DISTRIBUTION (ENERGY)	7.657	2.472	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	2.451	2.451	" "
TRANS RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

GENERAL RATE G-1 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$0.00	$4.31	PER KW
DISTRIBUTION (DEMAND)	$0.00	$0.00	PER KW
	< 1800 KWH	>1800 KWH	
DISTRIBUTION (ENERGY)	7.657	2.472	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	2.451	2.451	" "
TRANS RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	AVERAGE 0.512 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	100	37,403	$5,771.30	$2,633.92	$3,137.38	$5,723.05	$2,633.92	$3,089.13	($48.25)	-0.8%
	150	56,105	$8,476.95	$3,950.91	$4,526.04	$8,404.57	$3,950.91	$4,453.66	(72.38)	-0.9%
	200	74,807	$11,182.60	$5,267.91	$5,914.69	$11,086.10	$5,267.91	$5,818.19	(96.50)	-0.9%
	250	93,508	$13,888.12	$6,584.83	$7,303.29	$13,767.50	$6,584.83	$7,182.67	(120.62)	-0.9%
	300	112,210	$16,593.78	$7,901.83	$8,691.95	$16,449.02	$7,901.83	$8,547.19	(144.76)	-0.9%
	350	130,912	$19,299.42	$9,218.82	$10,080.60	$19,130.54	$9,218.82	$9,911.72	(168.88)	-0.9%
	400	149,613	$22,004.95	$10,535.75	$11,469.20	$21,811.95	$10,535.75	$11,276.20	(193.00)	-0.9%
	450	168,315	$24,710.59	$11,852.74	$12,857.85	$24,493.47	$11,852.74	$12,640.73	(217.12)	-0.9%
	500	187,017	$27,416.25	$13,169.74	$14,246.51	$27,175.00	$13,169.74	$14,005.26	(241.25)	-0.9%
AVG.USE	272	101,737	$15,078.63	$7,164.32	$7,914.31	$14,947.39	$7,164.32	$7,783.07	(131.24)	-0.9%

Current

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	HIGH 0.712 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	100	51,976	$7,599.86	$3,660.15	$3,939.71	$7,532.81	$3,660.15	$3,872.66	($67.05)	-0.9%
	150	77,964	$11,219.72	$5,490.22	$5,729.50	$11,119.15	$5,490.22	$5,628.93	(100.57)	-0.9%
	200	103,952	$14,839.59	$7,320.30	$7,519.29	$14,705.50	$7,320.30	$7,385.20	(134.09)	-0.9%
	250	129,940	$18,459.46	$9,150.37	$9,309.09	$18,291.83	$9,150.37	$9,141.46	(167.63)	-0.9%
	300	155,928	$22,079.33	$10,980.45	$11,098.88	$21,878.18	$10,980.45	$10,897.73	(201.15)	-0.9%
	350	181,916	$25,699.19	$12,810.52	$12,888.67	$25,464.52	$12,810.52	$12,654.00	(234.67)	-0.9%
	400	207,904	$29,319.06	$14,640.60	$14,678.46	$29,050.86	$14,640.60	$14,410.26	(268.20)	-0.9%
	450	233,892	$32,938.92	$16,470.67	$16,468.25	$32,637.20	$16,470.67	$16,166.53	(301.72)	-0.9%
	500	259,880	$36,558.79	$18,300.75	$18,258.04	$36,223.55	$18,300.75	$17,922.80	(335.24)	-0.9%
AVG.USE	272	141,375	$20,052.24	$9,955.63	$10,096.61	$19,869.87	$9,955.63	$9,914.24	(182.37)	-0.9%

Current

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	LOW 0.312 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	100	22,776	$3,935.97	$1,603.89	$2,332.08	$3,906.59	$1,603.89	$2,302.70	($29.38)	-0.7%
	150	34,164	$5,723.89	$2,405.83	$3,318.06	$5,679.82	$2,405.83	$3,273.99	(44.07)	-0.8%
	200	45,552	$7,511.80	$3,207.77	$4,304.03	$7,453.04	$3,207.77	$4,245.27	(58.76)	-0.8%
	250	56,940	$9,299.72	$4,009.71	$5,290.01	$9,226.27	$4,009.71	$5,216.56	(73.45)	-0.8%
	300	68,328	$11,087.65	$4,811.66	$6,275.99	$10,999.50	$4,811.66	$6,187.84	(88.15)	-0.8%
	350	79,716	$12,875.56	$5,613.60	$7,261.96	$12,772.73	$5,613.60	$7,159.13	(102.83)	-0.8%
	400	91,104	$14,663.48	$6,415.54	$8,247.94	$14,545.95	$6,415.54	$8,130.41	(117.53)	-0.8%
	450	102,492	$16,451.40	$7,217.49	$9,233.91	$16,319.19	$7,217.49	$9,101.70	(132.21)	-0.8%
	500	113,880	$18,239.32	$8,019.43	$10,219.89	$18,092.41	$8,019.43	$10,072.98	(146.91)	-0.8%
AVG.USE	272	61,951	$10,086.44	$4,362.59	$5,723.85	$10,006.53	$4,362.59	$5,643.94	(79.91)	-0.8%

Current

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

MEDIUM GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$360.13	PER BILL
DISTRIBUTION (DEMAND)			$1.53	PER KW
TRANSMISSION (DEMAND)			$5.65	

	PEAK 27.08%	LOW A 26.80%	LOW B 46.12%	
DISTRIBUTION (ENERGY)	1.840	1.557	1.030	CENTS/KWH
TRANSITION	2.922	2.922	2.922	" "
TRANSMISSION	0.203	0.203	0.203	" "
TRANS RATE ADJ	0.006	0.006	0.006	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (SECONDARY)

LF = CUM % BILLS	AVERAGE 0.521 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	419	159,358	$23,429.33	$11,221.99	$12,207.34	$23,223.73	$11,221.99	$12,001.74	($205.60)	-0.9%
	490	186,362	$27,247.01	$13,123.61	$14,123.40	$27,006.58	$13,123.61	$13,882.97	(240.43)	-0.9%
	672	255,582	$37,033.02	$17,998.08	$19,034.94	$36,703.29	$17,998.08	$18,705.21	(329.73)	-0.9%
	893	339,635	$48,916.06	$23,917.10	$24,998.96	$48,477.89	$23,917.10	$24,560.79	(438.17)	-0.9%
	902	343,058	$49,399.98	$24,158.14	$25,241.84	$48,957.40	$24,158.14	$24,799.26	(442.58)	-0.9%
	1,024	389,458	$55,959.82	$27,425.63	$28,534.19	$55,457.37	$27,425.63	$28,031.74	(502.45)	-0.9%
	1,143	434,717	$62,358.34	$30,612.77	$31,745.57	$61,797.50	$30,612.77	$31,184.73	(560.84)	-0.9%
	1,673	636,292	$90,856.10	$44,807.68	$46,048.42	$90,035.20	$44,807.68	$45,227.52	(820.90)	-0.9%
	2,293	872,097	$124,193.15	$61,413.07	$62,780.08	$123,068.03	$61,413.07	$61,654.96	(1,125.12)	-0.9%
AVG.USE	1,285	488,724	$69,993.60	$34,415.94	$35,577.66	$69,363.08	$34,415.94	$34,947.14	(630.52)	-0.9%

Current

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	
	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	
	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (SECONDARY)

LF = CUM % BILLS	HIGH 0.721 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	419	220,532	$30,377.70	$15,529.86	$14,847.84	$30,093.19	$15,529.86	$14,563.33	($284.51)	-0.9%
	490	257,902	$35,372.80	$18,161.46	$17,211.34	$35,040.08	$18,161.46	$16,878.62	(332.72)	-0.9%
	672	353,694	$48,176.97	$24,907.13	$23,269.84	$47,720.65	$24,907.13	$22,813.52	(456.32)	-0.9%
	893	470,013	$63,724.90	$33,098.32	$30,626.58	$63,118.52	$33,098.32	$30,020.20	(606.38)	-1.0%
	902	474,750	$64,358.08	$33,431.90	$30,926.18	$63,745.59	$33,431.90	$30,313.69	(612.49)	-1.0%
	1,024	538,962	$72,941.06	$37,953.70	$34,987.36	$72,245.73	$37,953.70	$34,292.03	(695.33)	-1.0%
	1,143	601,595	$81,312.99	$42,364.32	$38,948.67	$80,536.85	$42,364.32	$38,172.53	(776.14)	-1.0%
	1,673	880,550	$118,599.87	$62,008.33	$56,591.54	$117,463.85	$62,008.33	$55,455.52	(1,136.02)	-1.0%
	2,293	1,206,875	$162,218.52	$84,988.14	$77,230.38	$160,661.50	$84,988.14	$75,673.36	(1,557.02)	-1.0%
AVG.USE	1,285	676,334	$91,303.07	$47,627.44	$43,675.63	$90,430.51	$47,627.44	$42,803.07	(872.56)	-1.0%

Current

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	

	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	

	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (SECONDARY)

LF = CUM % BILLS	LOW 0.321 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	419	98,184	$16,480.95	$6,914.12	$9,566.83	$16,354.28	$6,914.12	$9,440.16	($126.67)	-0.8%
	490	114,822	$19,121.23	$8,085.77	$11,035.46	$18,973.09	$8,085.77	$10,887.32	(148.14)	-0.8%
	672	157,470	$25,889.09	$11,089.04	$14,800.05	$25,685.94	$11,089.04	$14,596.90	(203.15)	-0.8%
	893	209,257	$34,107.23	$14,735.88	$19,371.35	$33,837.26	$14,735.88	$19,101.38	(269.97)	-0.8%
	902	211,366	$34,441.90	$14,884.39	$19,557.51	$34,169.21	$14,884.39	$19,284.82	(272.69)	-0.8%
	1,024	239,954	$38,978.58	$16,897.56	$22,081.02	$38,669.01	$16,897.56	$21,771.45	(309.57)	-0.8%
	1,143	267,839	$43,403.69	$18,861.22	$24,542.47	$43,058.15	$18,861.22	$24,196.93	(345.54)	-0.8%
	1,673	392,034	$63,112.34	$27,607.03	$35,505.31	$62,606.56	$27,607.03	$34,999.53	(505.78)	-0.8%
	2,293	537,319	$86,167.77	$37,838.00	$48,329.77	$85,474.56	$37,838.00	$47,636.56	(693.21)	-0.8%
AVG.USE	1,285	301,114	$48,684.14	$21,204.45	$27,479.69	$48,295.66	$21,204.45	$27,091.21	(388.48)	-0.8%

Current

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.684	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

Proposed

LARGE GENERAL TOU RATE G-3 (SECONDARY)

DELIVERY SERVICES:

	PEAK 25.93%	LOW A 26.06%	LOW B 48.02%	
CUSTOMER			$900.00	PER BILL
DISTRIBUTION (DEMAND)			$0.88	PER KW
TRANSMISSION (DEMAND)			$3.00	
TRANSITION (DEMAND)			$6.69	
DISTRIBUTION (ENERGY)	1.308	1.208	0.854	CENTS/KWH
TRANSITION	2.202	2.202	2.202	" "
TRANSMISSION	0.000	0.000	0.000	" "
TRANS RATE ADJ	0.066	0.066	0.066	" "
DISTRIBUTION ADJ	0.555	0.555	0.555	
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	6.988	6.988	6.988	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL POWER RATE G-4

LF = CUM % BILLS	AVERAGE 0.225 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	11	1,790	$289.54	$132.93	$156.61	$287.23	$132.93	$154.30	($2.31)	-0.8%
20	14	2,260	$364.49	$167.82	$196.67	$361.58	$167.82	$193.76	(2.91)	-0.8%
30	22	3,555	$570.12	$263.99	$306.13	$565.54	$263.99	$301.55	(4.58)	-0.8%
40	27	4,443	$709.32	$329.92	$379.40	$703.59	$329.92	$373.67	(5.73)	-0.8%
50	32	5,341	$849.97	$396.64	$453.33	$843.08	$396.64	$446.44	(6.89)	-0.8%
60	46	7,535	$1,199.98	$559.58	$640.40	$1,190.26	$559.58	$630.68	(9.72)	-0.8%
70	57	9,456	$1,501.82	$702.23	$799.59	$1,489.62	$702.23	$787.39	(12.20)	-0.8%
80	77	12,681	$2,014.16	$941.72	$1,072.44	$1,997.80	$941.72	$1,056.08	(16.36)	-0.8%
90	111	18,255	$2,897.56	$1,355.62	$1,541.94	$2,874.01	$1,355.62	$1,518.39	(23.55)	-0.8%
AVG.USE	42	6,844	$1,091.19	$508.24	$582.95	$1,082.36	$508.24	$574.12	(8.83)	-0.8%

Current

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.684	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION (ENERGY)	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.555	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL POWER RATE G-4

LF = CUM % BILLS	HIGH 0.325 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	8	1,790	$278.59	$132.93	$145.66	$276.28	$132.93	$143.35	($2.31)	-0.8%
20	10	2,260	$349.89	$167.82	$182.07	$346.98	$167.82	$179.16	(2.91)	-0.8%
30	15	3,555	$544.57	$263.99	$280.58	$539.99	$263.99	$276.00	(4.58)	-0.8%
40	19	4,443	$680.12	$329.92	$350.20	$674.39	$329.92	$344.47	(5.73)	-0.8%
50	23	5,341	$817.12	$396.64	$420.48	$810.23	$396.64	$413.59	(6.89)	-0.8%
60	32	7,535	$1,148.88	$559.58	$589.30	$1,139.16	$559.58	$579.58	(9.72)	-0.8%
70	40	9,456	$1,439.77	$702.23	$737.54	$1,427.57	$702.23	$725.34	(12.20)	-0.8%
80	53	12,681	$1,926.56	$941.72	$984.84	$1,910.20	$941.72	$968.48	(16.36)	-0.8%
90	77	18,255	$2,773.46	$1,355.62	$1,417.84	$2,749.91	$1,355.62	$1,394.29	(23.55)	-0.8%
AVG.USE	29	6,844	$1,043.74	$508.24	$535.50	$1,034.91	$508.24	$526.67	(8.83)	-0.8%

Current

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.684	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION (ENERGY)	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.555	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
GENERAL POWER RATE G-4

LF = CUM % BILLS	LOW 0.125 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	20	1,790	$322.39	$132.93	$189.46	$320.08	$132.93	$187.15	($2.31)	-0.7%
20	25	2,260	$404.64	$167.82	$236.82	$401.73	$167.82	$233.91	(2.91)	-0.7%
30	39	3,555	$632.17	$263.99	$368.18	$627.59	$263.99	$363.60	(4.58)	-0.7%
40	49	4,443	$789.62	$329.92	$459.70	$783.89	$329.92	$453.97	(5.73)	-0.7%
50	59	5,341	$948.52	$396.64	$551.88	$941.63	$396.64	$544.99	(6.89)	-0.7%
60	83	7,535	$1,335.03	$559.58	$775.45	$1,325.31	$559.58	$765.73	(9.72)	-0.7%
70	104	9,456	$1,673.37	$702.23	$971.14	$1,661.17	$702.23	$958.94	(12.20)	-0.7%
80	139	12,681	$2,240.46	$941.72	$1,298.74	$2,224.10	$941.72	$1,282.38	(16.36)	-0.7%
90	200	18,255	$3,222.41	$1,355.62	$1,866.79	$3,198.86	$1,355.62	$1,843.24	(23.55)	-0.7%
AVG.USE	75	6,844	$1,211.64	$508.24	$703.40	$1,202.81	$508.24	$694.57	(8.83)	-0.7%

Current

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.684	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL POWER RATE G-4

DELIVERY SERVICES:

CUSTOMER		$5.53	PER BILL
DISTRIBUTION (DEMAND)		$1.75	PER KW
TRANSMISSION (DEMAND)		$1.90	
DISTRIBUTION (ENERGY)	ALL KWH @	2.060	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION (ENERGY)	" "	0.228	" "
TRANS RATE ADJ	" "	0.003	" "
DISTRIBUTION ADJ	" "	0.555	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
COMMERCIAL SPACE HEATING RATE G-5

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		93	$21.10	$6.91	$14.19	$20.98	$6.91	$14.07	($0.12)	-0.6%
20		194	$38.14	$14.41	$23.73	$37.89	$14.41	$23.48	(0.25)	-0.7%
30		283	$53.16	$21.02	$32.14	$52.80	$21.02	$31.78	(0.36)	-0.7%
40		388	$70.88	$28.81	$42.07	$70.38	$28.81	$41.57	(0.50)	-0.7%
50		505	$90.62	$37.50	$53.12	$89.97	$37.50	$52.47	(0.65)	-0.7%
60		689	$121.68	$51.17	$70.51	$120.79	$51.17	$69.62	(0.89)	-0.7%
70		984	$171.46	$73.07	$98.39	$170.19	$73.07	$97.12	(1.27)	-0.7%
80		1,490	$256.86	$110.65	$146.21	$254.93	$110.65	$144.28	(1.93)	-0.8%
90		2,902	$495.14	$215.50	$279.64	$491.40	$215.50	$275.90	(3.74)	-0.8%
AVG.USE		1,563	$269.17	$116.07	$153.10	$267.16	$116.07	$151.09	(2.01)	-0.7%

Current

COMMERCIAL SPACE HEATING RATE G-5

DELIVERY SERVICES:

CUSTOMER		$5.40	PER BILL
DISTRIBUTION (ENERGY)	ALL KWH @	3.667	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.877	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.684	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

COMMERCIAL SPACE HEATING RATE G-5

DELIVERY SERVICES:

CUSTOMER		$5.40	PER BILL
DISTRIBUTION (ENERGY)	ALL KWH @	3.667	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION (ENERGY)	" "	1.877	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.555	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
ALL ELECTRIC SCHOOLS RATE G-6

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		7,440	$1,112.03	$552.49	$559.54	$1,102.43	$552.49	$549.94	($9.60)	-0.9%
20		18,000	$2,651.89	$1,336.68	$1,315.21	$2,628.67	$1,336.68	$1,291.99	(23.22)	-0.9%
30		30,000	$4,401.73	$2,227.80	$2,173.93	$4,363.03	$2,227.80	$2,135.23	(38.70)	-0.9%
40		38,160	$5,591.62	$2,833.76	$2,757.86	$5,542.39	$2,833.76	$2,708.63	(49.23)	-0.9%
50		44,340	$6,492.79	$3,292.69	$3,200.10	$6,435.59	$3,292.69	$3,142.90	(57.20)	-0.9%
60		54,081	$7,913.25	$4,016.07	$3,897.18	$7,843.49	$4,016.07	$3,827.42	(69.76)	-0.9%
70		63,240	$9,248.78	$4,696.20	$4,552.58	$9,167.20	$4,696.20	$4,471.00	(81.58)	-0.9%
80		95,220	$13,912.11	$7,071.04	$6,841.07	$13,789.28	$7,071.04	$6,718.24	(122.83)	-0.9%
90		125,370	$18,308.59	$9,309.98	$8,998.61	$18,146.86	$9,309.98	$8,836.88	(161.73)	-0.9%
AVG.USE		88,287	$12,901.14	$6,556.19	$6,344.95	$12,787.25	$6,556.19	$6,231.06	(113.89)	-0.9%

Current

ALL ELECTRIC SCHOOLS RATE G-6

DELIVERY SERVICES:

CUSTOMER		$27.13	PER BILL
DISTRIBUTION (ENERGY)	ALL KWH @	1.696	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION	" "	1.554	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.684	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

ALL ELECTRIC SCHOOLS RATE G-6

DELIVERY SERVICES:

CUSTOMER		$27.13	PER BILL
DISTRIBUTION (ENERGY)	ALL KWH @	1.696	CENTS/KWH
TRANSITION	" "	2.922	" "
TRANSMISSION (ENERGY)	" "	1.554	" "
TRANS RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.555	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL TOU RATE G-7 (ANNUAL)

LF = 0.466 CUM % BILLS	AVERAGE MONTHLY KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	29	$12.94	$2.15	$10.79	$12.91	$2.15	$10.76	($0.03)	-0.2%
20	1	491	$82.77	$36.46	$46.31	$82.14	$36.46	$45.68	(0.63)	-0.8%
30	3	908	$155.71	$67.45	$88.26	$154.54	$67.45	$87.09	(1.17)	-0.8%
40	6	1,987	$324.72	$147.55	$177.17	$322.16	$147.55	$174.61	(2.56)	-0.8%
50	12	4,013	$645.46	$298.01	$347.45	$640.29	$298.01	$342.28	(5.17)	-0.8%
60	25	8,483	$1,351.01	$629.98	$721.03	$1,340.07	$629.98	$710.09	(10.94)	-0.8%
70	35	11,755	$1,871.73	$872.93	$998.80	$1,856.57	$872.93	$983.64	(15.16)	-0.8%
80	43	14,470	$2,301.13	$1,074.52	$1,226.61	$2,282.47	$1,074.52	$1,207.95	(18.66)	-0.8%
90	61	20,608	$3,271.20	$1,530.31	$1,740.89	$3,244.62	$1,530.31	$1,714.31	(26.58)	-0.8%
AVG.USE	14	4,742	$759.44	$352.14	$407.30	$753.32	$352.14	$401.18	(6.12)	-0.8%

Current

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
	PEAK 23.58%	OFF PK 76.42%	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
	PEAK 23.58%	OFF PK 76.42%	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL TOU RATE G-7 (ANNUAL)

LF = CUM % BILLS	HIGH 0.666 MONTHLY KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	29	$12.94	$2.15	$10.79	$12.91	$2.15	$10.76	($0.03)	-0.2%
20	1	491	$82.77	$36.46	$46.31	$82.14	$36.46	$45.68	(0.63)	-0.8%
30	2	908	$146.71	$67.45	$79.26	$145.54	$67.45	$78.09	(1.17)	-0.8%
40	4	1,987	$306.72	$147.55	$159.17	$304.16	$147.55	$156.61	(2.56)	-0.8%
50	8	4,013	$609.46	$298.01	$311.45	$604.29	$298.01	$306.28	(5.17)	-0.8%
60	17	8,483	$1,279.01	$629.98	$649.03	$1,268.07	$629.98	$638.09	(10.94)	-0.9%
70	24	11,755	$1,772.73	$872.93	$899.80	$1,757.57	$872.93	$884.64	(15.16)	-0.9%
80	30	14,470	$2,184.13	$1,074.52	$1,109.61	$2,165.47	$1,074.52	$1,090.95	(18.66)	-0.9%
90	42	20,608	$3,100.20	$1,530.31	$1,569.89	$3,073.62	$1,530.31	$1,543.31	(26.58)	-0.9%
AVG.USE	10	4,742	$723.44	$352.14	$371.30	$717.32	$352.14	$365.18	(6.12)	-0.8%

Current

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

	PEAK 23.58%	OFF PK 76.42%	
CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

	PEAK 23.58%	OFF PK 76.42%	
CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL TOU RATE G-7 (ANNUAL)

LF = CUM % BILLS	LOW 0.266 MONTHLY KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	29	$12.94	$2.15	$10.79	$12.91	$2.15	$10.76	($0.03)	-0.2%
20	3	491	$100.77	$36.46	$64.31	$100.14	$36.46	$63.68	(0.63)	-0.6%
30	5	908	$173.71	$67.45	$106.26	$172.54	$67.45	$105.09	(1.17)	-0.7%
40	10	1,987	$360.72	$147.55	$213.17	$358.16	$147.55	$210.61	(2.56)	-0.7%
50	21	4,013	$726.46	$298.01	$428.45	$721.29	$298.01	$423.28	(5.17)	-0.7%
60	44	8,483	$1,522.01	$629.98	$892.03	$1,511.07	$629.98	$881.09	(10.94)	-0.7%
70	61	11,755	$2,105.73	$872.93	$1,232.80	$2,090.57	$872.93	$1,217.64	(15.16)	-0.7%
80	75	14,470	$2,589.13	$1,074.52	$1,514.61	$2,570.47	$1,074.52	$1,495.95	(18.66)	-0.7%
90	106	20,608	$3,676.20	$1,530.31	$2,145.89	$3,649.62	$1,530.31	$2,119.31	(26.58)	-0.7%
AVG.USE	24	4,742	$849.44	$352.14	$497.30	$843.32	$352.14	$491.18	(6.12)	-0.7%

Current

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
	PEAK 23.58%	OFF PK 76.42%	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-7 (ANNUAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.35	PER KW
TRANSMISSION (DEMAND)		$5.65	
	PEAK 23.58%	OFF PK 76.42%	
DISTRIBUTION (ENERGY)	2.358	1.669	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.002	0.002	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL TOU RATE G-7 (SEASONAL)

LF = 0.172 CUM % BILLS	AVERAGE WINTER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	0	$9.13	$0.00	$9.13	$9.13	$0.00	$9.13	$0.00	0.0%
20	39	4,940	$986.51	$366.84	$619.67	$980.14	$366.84	$613.30	(6.37)	-0.6%
30	66	8,211	$1,640.49	$609.75	$1,030.74	$1,629.90	$609.75	$1,020.15	(10.59)	-0.6%
40	79	9,901	$1,972.89	$735.25	$1,237.64	$1,960.11	$735.25	$1,224.86	(12.78)	-0.6%
50	86	10,800	$2,150.19	$802.01	$1,348.18	$2,136.26	$802.01	$1,334.25	(13.93)	-0.6%
60	92	11,460	$2,285.34	$851.02	$1,434.32	$2,270.55	$851.02	$1,419.53	(14.79)	-0.6%
70	100	12,560	$2,499.02	$932.71	$1,566.31	$2,482.82	$932.71	$1,550.11	(16.20)	-0.6%
80	116	14,540	$2,892.90	$1,079.74	$1,813.16	$2,874.14	$1,079.74	$1,794.40	(18.76)	-0.6%
90	138	17,280	$3,437.14	$1,283.21	$2,153.93	$3,414.85	$1,283.21	$2,131.64	(22.29)	-0.6%
AVG.USE	4	532	$113.23	$39.51	$73.72	$112.55	$39.51	$73.04	(0.68)	-0.6%

Current

SMALL GENERAL TOU RATE G-7 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.39	PER KW
TRANSMISSION (DEMAND)		$2.39	
	PEAK 7.02%	OFF PK 92.98%	
DISTRIBUTION (ENERGY)	4.542	3.829	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.011	0.011	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-7 (SEASONAL)

DELIVERY SERVICES:

CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.39	PER KW
TRANSMISSION (DEMAND)		$2.39	
	PEAK 7.02%	OFF PK 92.98%	
DISTRIBUTION (ENERGY)	4.542	3.829	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.011	0.011	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

COMMONWEALTH ELECTRIC COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL TOU RATE G-7 (SEASONAL)

LF = 0.172 CUM % BILLS	AVERAGE SUMMER KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	0	0	$9.13	$0.00	$9.13	$9.13	$0.00	$9.13	$0.00	0.0%
20	62	7,745	$1,546.43	$575.14	$971.29	$1,536.44	$575.14	$961.30	(9.99)	-0.6%
30	82	10,320	$2,054.00	$766.36	$1,287.64	$2,040.69	$766.36	$1,274.33	(13.31)	-0.6%
40	96	11,989	$2,388.98	$890.30	$1,498.68	$2,373.51	$890.30	$1,483.21	(15.47)	-0.6%
50	102	12,756	$2,540.41	$947.26	$1,593.15	$2,523.96	$947.26	$1,576.70	(16.45)	-0.6%
60	108	13,523	$2,691.85	$1,004.22	$1,687.63	$2,674.41	$1,004.22	$1,670.19	(17.44)	-0.6%
70	114	14,290	$2,843.29	$1,061.18	$1,782.11	$2,824.85	$1,061.18	$1,763.67	(18.44)	-0.6%
80	119	14,924	$2,968.69	$1,108.26	$1,860.43	$2,949.44	$1,108.26	$1,841.18	(19.25)	-0.6%
90	124	15,532	$3,090.14	$1,153.41	$1,936.73	$3,070.11	$1,153.41	$1,916.70	(20.03)	-0.6%
AVG.USE	7	919	$189.48	$68.24	$121.24	$188.29	$68.24	$120.05	(1.19)	-0.6%

Current

SMALL GENERAL TOU RATE G-7 (SEASONAL)

DELIVERY SERVICES:

	PEAK 7.02%	OFF PK 92.98%	
CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.39	PER KW
TRANSMISSION (DEMAND)		$2.39	
DISTRIBUTION (ENERGY)	4.542	3.829	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.011	0.011	" "
DISTRIBUTION ADJ	0.684	0.684	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-7 (SEASONAL)

DELIVERY SERVICES:

	PEAK 7.02%	OFF PK 92.98%	
CUSTOMER		$9.13	PER BILL
DISTRIBUTION (DEMAND)		$3.39	PER KW
TRANSMISSION (DEMAND)		$2.39	
DISTRIBUTION (ENERGY)	4.542	3.829	CENTS/KWH
TRANSITION	2.922	2.922	" "
TRANSMISSION	0.000	0.000	" "
TRANS RATE ADJ	0.011	0.011	" "
DISTRIBUTION ADJ	0.555	0.555	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

CAMBRIDGE ELECTRIC TYPICAL BILL COMPARISONS AUGUST 2013 DELIVERY RATES						
					Proposed vs. Current Change in Total Bill	
Class	Rate	Load Fact	Avg Kw	Avg Kwh	Amount	%
Residential	Res Rate R-1			393	(0.51)	-0.8%
	Res Assist R-2			333	(0.32)	-0.8%
	Res Space Heat R-3			714	(0.93)	-0.8%
	Res Assist Spc Htg R-4			556	(0.54)	-0.8%
	Res TOU R-5			841	(1.09)	-0.9%
	Res Heating TOU R-6			1,227	(1.58)	-1.0%
Small Comm.	General Non-Demand G-0			689	(0.89)	-0.9%
	General G-1	0.440	28	8,746	(11.28)	-1.0%
	General G-1	0.520	23	8,746	(11.28)	-1.1%
	General G-1	0.320	37	8,746	(11.28)	-0.9%
	General Opt TOU G-4	0.535	36	14,299	(18.45)	-1.1%
	General Opt TOU G-4	0.635	30	14,299	(18.45)	-1.2%
	General Opt TOU G-4	0.435	44	14,299	(18.45)	-1.1%
	Comm Spc Htg G-5			15,520	-20.02	-1.0%
	General Opt TOU Non-Demand G-6			810	-1.04	-0.9%
Lg Comm/Ind	Large Gen TOU G-2	0.570	303	123,988	(159.95)	-1.1%
	Large Gen TOU G-2	0.745	303	167,857	(216.53)	-1.2%
	Large Gen TOU G-2	0.345	303	77,684	(100.21)	-1.0%
	Large Gen TOU Prim G-3	0.665	1506	743,204	(958.73)	-1.3%
	Large Gen TOU Prim G-3	0.727	1506	814,674	(1,050.93)	-1.3%
	Large Gen TOU Prim G-3	0.527	1506	590,581	(761.85)	-1.2%

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL RATE R-1

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		106	$22.15	$7.96	$14.19	$22.01	$7.96	$14.05	($0.14)	-0.6%
20		144	$27.62	$10.81	$16.81	$27.44	$10.81	$16.63	($0.18)	-0.7%
30		185	$33.54	$13.89	$19.65	$33.30	$13.89	$19.41	($0.24)	-0.7%
40		227	$39.59	$17.04	$22.55	$39.29	$17.04	$22.25	($0.30)	-0.8%
50		272	$46.07	$20.42	$25.65	$45.72	$20.42	$25.30	($0.35)	-0.8%
60		325	$53.70	$24.39	$29.31	$53.29	$24.39	$28.90	($0.41)	-0.8%
70		392	$63.36	$29.42	$33.94	$62.86	$29.42	$33.44	($0.50)	-0.8%
80		488	$77.20	$36.63	$40.57	$76.57	$36.63	$39.94	($0.63)	-0.8%
90		646	$99.97	$48.49	$51.48	$99.14	$48.49	$50.65	($0.83)	-0.8%
AVG.USE		393	$63.51	$29.50	$34.01	$63.00	$29.50	$33.50	($0.51)	-0.8%

Current

RESIDENTIAL RATE R-1

DELIVERY SERVICES:

CUSTOMER		$6.87	PER BILL
DISTRIBUTION	ALL KWH @	3.835	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.163	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.974	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RESIDENTIAL RATE R-1

DELIVERY SERVICES:

CUSTOMER		$6.87	PER BILL
DISTRIBUTION	ALL KWH @	3.835	CENTS/KWH
TRANSITION	" "	(0.366)	" "
TRANSMISSION	" "	2.163	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.845	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL ASSISTANCE RATE R-2 (R1)

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		116	$17.11	$6.54	$10.57	$16.99	$6.54	$10.45	($0.12)	-0.7%
20		156	$21.22	$8.79	$12.43	$21.07	$8.79	$12.28	($0.15)	-0.7%
30		194	$25.14	$10.94	$14.20	$24.95	$10.94	$14.01	($0.19)	-0.8%
40		225	$28.33	$12.68	$15.65	$28.11	$12.68	$15.43	($0.22)	-0.8%
50		266	$32.55	$14.99	$17.56	$32.29	$14.99	$17.30	($0.26)	-0.8%
60		309	$36.98	$17.42	$19.56	$36.68	$17.42	$19.26	($0.30)	-0.8%
70		362	$42.44	$20.41	$22.03	$42.09	$20.41	$21.68	($0.35)	-0.8%
80		431	$49.55	$24.30	$25.25	$49.13	$24.30	$24.83	($0.42)	-0.8%
90		541	$60.87	$30.50	$30.37	$60.35	$30.50	$29.85	($0.52)	-0.9%
AVG.USE		333	$39.45	$18.77	$20.68	$39.13	$18.77	$20.36	($0.32)	-0.8%

Current

RESIDENTIAL ASSISTANCE RATE R-2

DELIVERY SERVICES:

CUSTOMER		$6.87	PER BILL
DISTRIBUTION	ALL KWH @	3.835	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.163	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.274	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 24.9%

Proposed

RESIDENTIAL ASSISTANCE RATE R-2

DELIVERY SERVICES:

CUSTOMER		$6.87	PER BILL
DISTRIBUTION	ALL KWH @	3.835	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.163	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.145	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

LOW INCOME DISCOUNT: 24.9%

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SPACE HEATING RATE R-3

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		225	$42.51	$16.89	$25.62	$42.22	$16.89	$25.33	($0.29)	-0.7%
20		305	$54.86	$22.89	$31.97	$54.47	$22.89	$31.58	($0.39)	-0.7%
30		379	$66.29	$28.45	$37.84	$65.80	$28.45	$37.35	($0.49)	-0.7%
40		458	$78.49	$34.38	$44.11	$77.90	$34.38	$43.52	($0.59)	-0.8%
50		544	$91.77	$40.83	$50.94	$91.06	$40.83	$50.23	($0.71)	-0.8%
60		643	$107.05	$48.26	$58.79	$106.22	$48.26	$57.96	($0.83)	-0.8%
70		761	$125.28	$57.12	$68.16	$124.29	$57.12	$67.17	($0.99)	-0.8%
80		906	$147.66	$68.00	$79.66	$146.49	$68.00	$78.49	($1.17)	-0.8%
90		1,134	$182.87	$85.12	$97.75	$181.41	$85.12	$96.29	($1.46)	-0.8%
AVG.USE		714	$118.02	$53.59	$64.43	$117.09	$53.59	$63.50	($0.93)	-0.8%

Current

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

CUSTOMER		$7.77	PER BILL
DISTRIBUTION	ALL KWH @	4.483	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.544	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.974	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

RES SPACE HEATING RATE R-3

DELIVERY SERVICES:

CUSTOMER		$7.77	PER BILL
DISTRIBUTION	ALL KWH @	4.483	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.544	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.845	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RES ASSISTANCE SPACE HEATING RATE R-4 (R3)

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		190	$26.90	$10.72	$16.18	$26.72	$10.72	$16.00	($0.18)	-0.7%
20		249	$33.44	$14.05	$19.39	$33.20	$14.05	$19.15	($0.24)	-0.7%
30		314	$40.65	$17.72	$22.93	$40.34	$17.72	$22.62	($0.31)	-0.8%
40		387	$48.74	$21.84	$26.90	$48.36	$21.84	$26.52	($0.38)	-0.8%
50		502	$61.50	$28.34	$33.16	$61.01	$28.34	$32.67	($0.49)	-0.8%
60		574	$69.47	$32.40	$37.07	$68.92	$32.40	$36.52	($0.55)	-0.8%
70		671	$80.22	$37.87	$42.35	$79.57	$37.87	$41.70	($0.65)	-0.8%
80		741	$87.99	$41.83	$46.16	$87.27	$41.83	$45.44	($0.72)	-0.8%
90		912	$106.94	$51.48	$55.46	$106.06	$51.48	$54.58	($0.88)	-0.8%
AVG.USE		556	$67.47	$31.38	$36.09	$66.93	$31.38	$35.55	($0.54)	-0.8%

Current

RES ASSISTANCE SPACE HEATING RATE R-4

DELIVERY SERVICES:

CUSTOMER		$7.77	PER BILL
DISTRIBUTION	ALL KWH @	4.483	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.544	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.274	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

LOW INCOME DISCOUNT: 24.8%

Proposed

RES ASSISTANCE SPACE HEATING RATE R-4

DELIVERY SERVICES:

CUSTOMER		$7.77	PER BILL
DISTRIBUTION	ALL KWH @	4.483	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.544	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.145	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

LOW INCOME DISCOUNT: 24.8%

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL TOU RATE R-5

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		333	$55.15	$24.99	$30.16	$54.72	$24.99	$29.73	($0.43)	-0.8%
20		359	$58.65	$26.95	$31.70	$58.19	$26.95	$31.24	($0.46)	-0.8%
30		637	$95.95	$47.81	$48.14	$95.13	$47.81	$47.32	($0.82)	-0.9%
40		832	$122.12	$62.45	$59.67	$121.05	$62.45	$58.60	($1.07)	-0.9%
50		941	$136.75	$70.63	$66.12	$135.54	$70.63	$64.91	($1.21)	-0.9%
60		968	$140.38	$72.66	$67.72	$139.13	$72.66	$66.47	($1.25)	-0.9%
70		1,026	$148.16	$77.01	$71.15	$146.83	$77.01	$69.82	($1.33)	-0.9%
80		1,143	$163.86	$85.79	$78.07	$162.38	$85.79	$76.59	($1.48)	-0.9%
90		1,184	$169.36	$88.87	$80.49	$167.83	$88.87	$78.96	($1.53)	-0.9%
AVG.USE		841	$123.34	$63.13	$60.21	$122.25	$63.13	$59.12	($1.09)	-0.9%

Current

RESIDENTIAL TOU RATE R-5

DELIVERY SERVICES:

	PEAK	OFF-PEAK	
CUSTOMER		$10.47	PER BILL
	22.88%	77.12%	
DISTRIBUTION	10.209	2.026	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	4.859	0.000	" "
TRANSITION RATE ADJ	-0.004	-0.004	" "
DISTRIBUTION ADJ	0.974	0.974	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.452	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

RESIDENTIAL TOU RATE R-5

DELIVERY SERVICES:

	PEAK	OFF-PEAK	
CUSTOMER		$10.47	PER BILL
	22.88%	77.12%	
DISTRIBUTION	10.209	2.026	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	4.859	0.000	" "
TRANSITION RATE ADJ	(0.004)	(0.004)	" "
DISTRIBUTION ADJ	0.845	0.845	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.452	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
RESIDENTIAL SPACE HEATING TOU RATE R-6

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		440	$63.78	$33.03	$30.75	$63.21	$33.03	$30.18	($0.57)	-0.9%
20		497	$70.56	$37.30	$33.26	$69.91	$37.30	$32.61	($0.65)	-0.9%
30		507	$71.76	$38.06	$33.70	$71.10	$38.06	$33.04	($0.66)	-0.9%
40		633	$86.75	$47.51	$39.24	$85.94	$47.51	$38.43	($0.81)	-0.9%
50		1,043	$135.59	$78.29	$57.30	$134.24	$78.29	$55.95	($1.35)	-1.0%
60		1,212	$155.71	$90.97	$64.74	$154.15	$90.97	$63.18	($1.56)	-1.0%
70		1,231	$157.98	$92.40	$65.58	$156.39	$92.40	$63.99	($1.59)	-1.0%
80		1,865	$233.49	$139.99	$93.50	$231.08	$139.99	$91.09	($2.41)	-1.0%
90		2,268	$281.48	$170.24	$111.24	$278.56	$170.24	$108.32	($2.92)	-1.0%
AVG.USE		1,227	$157.50	$92.10	$65.40	$155.92	$92.10	$63.82	($1.58)	-1.0%

Current

RESIDENTIAL TOU RATE R-6

DELIVERY SERVICES:

	PEAK 4.46%	OFF-PEAK 95.54%	
CUSTOMER		$11.37	PER BILL
DISTRIBUTION	13.269	2.591	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	9.610	0.000	" "
TRANSITION RATE ADJ	-0.001	-0.001	" "
DISTRIBUTION ADJ	0.974	0.974	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.452	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

RESIDENTIAL TOU RATE R-6

DELIVERY SERVICES:

	PEAK 4.46%	OFF-PEAK 95.54%	
CUSTOMER		$11.37	PER BILL
DISTRIBUTION	13.269	2.591	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	9.610	0.000	" "
TRANSITION RATE ADJ	(0.001)	(0.001)	" "
DISTRIBUTION ADJ	0.845	0.845	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.452	7.452	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-0 (NON-DEMAND)

				Current			**Proposed**		**DIFFERENCE**	
CUM % BILLS	KW	MONTHLY KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10		23	$7.68	$1.71	$5.97	$7.65	$1.71	$5.94	($0.03)	-0.4%
20		59	$12.47	$4.38	$8.09	$12.40	$4.38	$8.02	($0.07)	-0.6%
30		118	$20.32	$8.76	$11.56	$20.17	$8.76	$11.41	($0.15)	-0.7%
40		193	$30.31	$14.33	$15.98	$30.06	$14.33	$15.73	($0.25)	-0.8%
50		301	$44.68	$22.35	$22.33	$44.30	$22.35	$21.95	($0.38)	-0.9%
60		464	$66.39	$34.46	$31.93	$65.79	$34.46	$31.33	($0.60)	-0.9%
70		684	$95.66	$50.79	$44.87	$94.78	$50.79	$43.99	($0.88)	-0.9%
80		1,013	$139.47	$75.23	$64.24	$138.16	$75.23	$62.93	($1.31)	-0.9%
90		1,588	$215.99	$117.92	$98.07	$213.95	$117.92	$96.03	($2.04)	-0.9%
AVG.USE		689	$96.34	$51.17	$45.17	$95.45	$51.17	$44.28	($0.89)	-0.9%

Current

GENERAL RATE G-0

DELIVERY SERVICES:

CUSTOMER		$4.62	PER BILL
DISTRIBUTION	ALL KWH @	3.420	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.028	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.503	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL RATE G-0

DELIVERY SERVICES:

CUSTOMER		$4.62	PER BILL
DISTRIBUTION	ALL KWH @	3.420	CENTS/KWH
TRANSITION	" "	-0.366	" "
TRANSMISSION	" "	2.028	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.374	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

LF = CUM % BILLS	AVERAGE 0.420 MONTHLY KW	MONTHLY KWH	TOTAL (Current)	SUPPLIER (Current)	DELIVERY (Current)	TOTAL (Proposed)	SUPPLIER (Proposed)	DELIVERY (Proposed)	DIFFERENCE AMOUNT	DIFFERENCE %
10	5	1,546	$196.35	$114.81	$81.54	$194.36	$114.81	$79.55	($1.99)	-1.0%
20	7	2,308	$284.96	$171.39	$113.57	$281.98	$171.39	$110.59	($2.98)	-1.0%
30	10	3,125	$388.36	$232.06	$156.30	$384.33	$232.06	$152.27	($4.03)	-1.0%
40	12	3,872	$482.11	$287.53	$194.58	$477.12	$287.53	$189.59	($4.99)	-1.0%
50	16	4,875	$625.18	$362.02	$263.16	$618.89	$362.02	$256.87	($6.29)	-1.0%
60	20	6,237	$800.73	$463.16	$337.57	$792.69	$463.16	$329.53	($8.04)	-1.0%
70	26	8,024	$1,040.89	$595.86	$445.03	$1,030.54	$595.86	$434.68	($10.35)	-1.0%
80	37	11,418	$1,491.85	$847.90	$643.95	$1,477.12	$847.90	$629.22	($14.73)	-1.0%
90	56	17,349	$2,277.00	$1,288.34	$988.66	$2,254.62	$1,288.34	$966.28	($22.38)	-1.0%
AVG.USE	28	8,746	$1,132.38	$649.48	$482.90	$1,121.10	$649.48	$471.62	($11.28)	-1.0%

Current

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	" "
TRANSMISSION	$6.04	$6.04	" "
TRANSITION RATE ADJ	$ 0.02	$ 0.02	
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.503	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	
TRANSMISSION	$6.04	$6.04	
TRANSITION RATE ADJ	$0.02	$0.02	
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.374	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
			" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

LF = CUM % BILLS	HIGH 0.520 MONTHLY KW	MONTHLY KWH	TOTAL	**Current** SUPPLIER	DELIVERY	TOTAL	**Proposed** SUPPLIER	DELIVERY	**DIFFERENCE** AMOUNT	%
10	4	1,546	$186.53	$114.81	$71.72	$184.54	$114.81	$69.73	($1.99)	-1.1%
20	6	2,308	$275.14	$171.39	$103.75	$272.16	$171.39	$100.77	($2.98)	-1.1%
30	8	3,125	$368.72	$232.06	$136.66	$364.69	$232.06	$132.63	($4.03)	-1.1%
40	10	3,872	$455.97	$287.53	$168.44	$450.98	$287.53	$163.45	($4.99)	-1.1%
50	13	4,875	$585.97	$362.02	$223.95	$579.68	$362.02	$217.66	($6.29)	-1.1%
60	16	6,237	$748.45	$463.16	$285.29	$740.41	$463.16	$277.25	($8.04)	-1.1%
70	21	8,024	$975.54	$595.86	$379.68	$965.19	$595.86	$369.33	($10.35)	-1.1%
80	30	11,418	$1,400.36	$847.90	$552.46	$1,385.63	$847.90	$537.73	($14.73)	-1.1%
90	45	17,349	$2,133.23	$1,288.34	$844.89	$2,110.85	$1,288.34	$822.51	($22.38)	-1.0%
AVG.USE	23	8,746	$1,067.03	$649.48	$417.55	$1,055.75	$649.48	$406.27	($11.28)	-1.1%

<u>Current</u>

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	" "
TRANSMISSION	$6.04	$6.04	" "
TRANSITION RATE ADJ			
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ		0.000	
DISTRIBUTION ADJ	" "	0.503	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

<u>Proposed</u>

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	
TRANSMISSION	$6.04	$6.04	
TRANSITION RATE ADJ	$0.02	$0.02	
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.374	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
			" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
GENERAL RATE G-1 (DEMAND)

LF = CUM % BILLS	LOW 0.320 MONTHLY KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	6	1,546	$206.17	$114.81	$91.36	$204.18	$114.81	$89.37	($1.99)	-1.0%
20	10	2,308	$314.42	$171.39	$143.03	$311.44	$171.39	$140.05	($2.98)	-0.9%
30	13	3,125	$427.57	$232.06	$195.51	$423.54	$232.06	$191.48	($4.03)	-0.9%
40	16	3,872	$534.39	$287.53	$246.86	$529.40	$287.53	$241.87	($4.99)	-0.9%
50	20	4,875	$677.46	$362.02	$315.44	$671.17	$362.02	$309.15	($6.29)	-0.9%
60	26	6,237	$879.15	$463.16	$415.99	$871.11	$463.16	$407.95	($8.04)	-0.9%
70	34	8,024	$1,145.45	$595.86	$549.59	$1,135.10	$595.86	$539.24	($10.35)	-0.9%
80	48	11,418	$1,635.62	$847.90	$787.72	$1,620.89	$847.90	$772.99	($14.73)	-0.9%
90	73	17,349	$2,499.19	$1,288.34	$1,210.85	$2,476.81	$1,288.34	$1,188.47	($22.38)	-0.9%
AVG.USE	37	8,746	$1,250.01	$649.48	$600.53	$1,238.73	$649.48	$589.25	($11.28)	-0.9%

Current

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	" "
TRANSMISSION	$6.04	$6.04	" "
TRANSITION RATE ADJ			
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ		0.000	
DISTRIBUTION ADJ	" "	0.503	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	

Proposed

GENERAL RATE G-1

DELIVERY SERVICES:

CUSTOMER		$7.32	PER BILL
	FIRST 10	OVER 10	
DISTRIBUTION (DEMAND)	$3.76	$7.01	PER KW
TRANSITION	$0.00	$0.00	
TRANSMISSION	$6.04	$6.04	
TRANSITION RATE ADJ	$0.02	$0.02	
DISTRIBUTION (ENERGY)	ALL KWH @	1.188	CENTS/KWH
TRANSMISSION		0.000	
TRANSITION	" "	-0.366	" "
TRANSITION RATE ADJ	" "	0.000	" "
DISTRIBUTION ADJ	" "	0.374	" "
DEFAULT SERV ADJ	" "	0.000	" "
DEMAND-SIDE MGT	" "	0.250	" "
RENEWABLE ENERGY	" "	0.050	" "
			" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	ALL KWH @	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER		0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	AVERAGE 0.550 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	75	30,690	$3,372.23	$2,221.65	$1,150.58	$3,332.64	$2,221.65	$1,110.99	($39.59)	-1.2%
	110	45,012	$4,957.44	$3,258.42	$1,699.02	$4,899.38	$3,258.42	$1,640.96	($58.06)	-1.2%
	130	53,196	$5,939.71	$3,850.86	$2,088.85	$5,871.08	$3,850.86	$2,020.22	($68.63)	-1.2%
	155	63,426	$7,167.53	$4,591.41	$2,576.12	$7,085.71	$4,591.41	$2,494.30	($81.82)	-1.1%
	188	76,930	$8,788.30	$5,568.96	$3,219.34	$8,689.06	$5,568.96	$3,120.10	($99.24)	-1.1%
	232	94,934	$10,949.20	$6,872.27	$4,076.93	$10,826.74	$6,872.27	$3,954.47	($122.46)	-1.1%
	300	122,760	$14,288.94	$8,886.60	$5,402.34	$14,130.58	$8,886.60	$5,243.98	($158.36)	-1.1%
	400	163,680	$19,200.25	$11,848.80	$7,351.45	$18,989.10	$11,848.80	$7,140.30	($211.15)	-1.1%
	660	270,072	$31,969.65	$19,550.51	$12,419.14	$31,621.26	$19,550.51	$12,070.75	($348.39)	-1.1%
AVG.USE	303	123,988	$14,436.31	$8,975.49	$5,460.82	$14,276.36	$8,975.49	$5,300.87	($159.95)	-1.1%

Current

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	

	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	

	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	HIGH 0.745 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	75	41,549	$4,315.44	$3,007.73	$1,307.71	$4,261.85	$3,007.73	$1,254.12	($53.59)	-1.2%
	110	60,938	$6,340.77	$4,411.30	$1,929.47	$6,262.16	$4,411.30	$1,850.86	($78.61)	-1.2%
	130	72,018	$7,574.58	$5,213.38	$2,361.20	$7,481.68	$5,213.38	$2,268.30	($92.90)	-1.2%
	155	85,867	$9,116.76	$6,215.91	$2,900.85	$9,005.99	$6,215.91	$2,790.08	($110.77)	-1.2%
	188	104,149	$11,152.55	$7,539.35	$3,613.20	$11,018.19	$7,539.35	$3,478.84	($134.36)	-1.2%
	232	128,524	$13,866.83	$9,303.85	$4,562.98	$13,701.04	$9,303.85	$4,397.19	($165.79)	-1.2%
	300	166,195	$18,061.70	$12,030.86	$6,030.84	$17,847.31	$12,030.86	$5,816.45	($214.39)	-1.2%
	400	221,593	$24,230.57	$16,041.12	$8,189.45	$23,944.72	$16,041.12	$7,903.60	($285.85)	-1.2%
	660	365,628	$40,269.65	$26,467.81	$13,801.84	$39,797.99	$26,467.81	$13,330.18	($471.66)	-1.2%
AVG.USE	303	167,857	$18,246.77	$12,151.17	$6,095.60	$18,030.24	$12,151.17	$5,879.07	($216.53)	-1.2%

Current

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	
	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	
	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-2 (SECONDARY)

LF = CUM % BILLS	LOW 0.345 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	75	19,229	$2,376.73	$1,391.99	$984.74	$2,351.93	$1,391.99	$959.94	($24.80)	-1.0%
	110	28,202	$3,497.32	$2,041.54	$1,455.78	$3,460.94	$2,041.54	$1,419.40	($36.38)	-1.0%
	130	33,330	$4,214.15	$2,412.76	$1,801.39	$4,171.15	$2,412.76	$1,758.39	($43.00)	-1.0%
	155	39,739	$5,110.08	$2,876.71	$2,233.37	$5,058.82	$2,876.71	$2,182.11	($51.26)	-1.0%
	188	48,200	$6,292.81	$3,489.20	$2,803.61	$6,230.64	$3,489.20	$2,741.44	($62.17)	-1.0%
	232	59,481	$7,869.76	$4,305.83	$3,563.93	$7,793.03	$4,305.83	$3,487.20	($76.73)	-1.0%
	300	76,915	$10,306.84	$5,567.88	$4,738.96	$10,207.62	$5,567.88	$4,639.74	($99.22)	-1.0%
	400	102,553	$13,890.75	$7,423.81	$6,466.94	$13,758.46	$7,423.81	$6,334.65	($132.29)	-1.0%
	660	169,212	$23,208.96	$12,249.26	$10,959.70	$22,990.67	$12,249.26	$10,741.41	($218.29)	-0.9%
AVG.USE	303	77,684	$10,414.34	$5,623.54	$4,790.80	$10,314.13	$5,623.54	$4,690.59	($100.21)	-1.0%

Current

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	

	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-2 (SECONDARY)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$4.06	$5.03	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$4.16	$8.54	

	PEAK 27.09%	LOW A 26.13%	LOW B 46.78%	
DISTRIBUTION (ENERGY)	1.009	1.009	1.009	CENTS/KWH
TRANSITION	-0.366	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.001	0.001	0.001	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (13.8 KV)

LF = CUM % BILLS	AVERAGE 0.663 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	210	103,634	$10,115.97	$7,502.07	$2,613.90	$9,982.28	$7,502.07	$2,480.21	($133.69)	-1.3%
	360	177,658	$17,765.01	$12,860.66	$4,904.35	$17,535.83	$12,860.66	$4,675.17	($229.18)	-1.3%
	530	261,552	$26,433.96	$18,933.75	$7,500.21	$26,096.55	$18,933.75	$7,162.80	($337.41)	-1.3%
	675	333,109	$33,828.08	$24,113.76	$9,714.32	$33,398.37	$24,113.76	$9,284.61	($429.71)	-1.3%
	975	481,158	$49,126.28	$34,831.03	$14,295.25	$48,505.58	$34,831.03	$13,674.55	($620.70)	-1.3%
	1,000	493,495	$50,401.09	$35,724.10	$14,676.99	$49,764.48	$35,724.10	$14,040.38	($636.61)	-1.3%
	1,500	740,243	$75,898.05	$53,586.19	$22,311.86	$74,943.14	$53,586.19	$21,356.95	($954.91)	-1.3%
	3,000	1,480,486	$152,388.85	$107,172.38	$45,216.47	$150,479.03	$107,172.38	$43,306.65	($1,909.82)	-1.3%
	5,000	2,467,476	$254,376.54	$178,620.59	$75,755.95	$251,193.49	$178,620.59	$72,572.90	($3,183.05)	-1.3%
AVG.USE	1,506	743,204	$76,204.02	$53,800.54	$22,403.48	$75,245.29	$53,800.54	$21,444.75	($958.73)	-1.3%

Current

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	
	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	CENTS/KWH
TRANSITION RATE ADJ	-0.033	-0.033	-0.033	" "
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	
	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	CENTS/KWH
TRANSITION RATE ADJ	(0.033)	(0.033)	(0.033)	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (13.8 KV)

LF = CUM % BILLS	HIGH 0.727 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	210	113,600	$10,952.70	$8,223.50	$2,729.20	$10,806.16	$8,223.50	$2,582.66	($146.54)	-1.3%
	360	194,743	$19,199.48	$14,097.45	$5,102.03	$18,948.26	$14,097.45	$4,850.81	($251.22)	-1.3%
	530	286,705	$28,545.80	$20,754.57	$7,791.23	$28,175.95	$20,754.57	$7,421.38	($369.85)	-1.3%
	675	365,143	$36,517.65	$26,432.70	$10,084.95	$36,046.62	$26,432.70	$9,613.92	($471.03)	-1.3%
	975	527,429	$53,011.19	$38,180.59	$14,830.60	$52,330.81	$38,180.59	$14,150.22	($680.38)	-1.3%
	1,000	540,952	$54,385.58	$39,159.52	$15,226.06	$53,687.76	$39,159.52	$14,528.24	($697.82)	-1.3%
	1,500	811,429	$81,874.83	$58,739.35	$23,135.48	$80,828.09	$58,739.35	$22,088.74	($1,046.74)	-1.3%
	3,000	1,622,857	$164,342.33	$117,478.62	$46,863.71	$162,248.84	$117,478.62	$44,770.22	($2,093.49)	-1.3%
	5,000	2,704,762	$274,299.07	$195,797.72	$78,501.35	$270,809.92	$195,797.72	$75,012.20	($3,489.15)	-1.3%
AVG.USE	1,506	814,674	$82,204.64	$58,974.25	$23,230.39	$81,153.71	$58,974.25	$22,179.46	($1,050.93)	-1.3%

Current

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	
	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	" "
TRANSITION RATE ADJ	-0.033	-0.033	-0.033	
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

CUSTOMER			$90.00	PER BILL
		< 100 KVA	> 100 KVA	
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	
	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	CENTS/KWH
TRANSITION RATE ADJ	(0.033)	(0.033)	(0.033)	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
LARGE GENERAL TOU RATE G-3 (13.8 KV)

LF = CUM % BILLS	LOW 0.527 MONTHLY KVA	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
	210	82,352	$8,329.12	$5,961.46	$2,367.66	$8,222.89	$5,961.46	$2,261.43	($106.23)	-1.3%
	360	141,175	$14,701.90	$10,219.66	$4,482.24	$14,519.79	$10,219.66	$4,300.13	($182.11)	-1.2%
	530	207,841	$21,924.38	$15,045.61	$6,878.77	$21,656.27	$15,045.61	$6,610.66	($268.11)	-1.2%
	675	264,703	$28,084.71	$19,161.85	$8,922.86	$27,743.25	$19,161.85	$8,581.40	($341.46)	-1.2%
	975	382,349	$40,830.27	$27,678.24	$13,152.03	$40,337.04	$27,678.24	$12,658.80	($493.23)	-1.2%
	1,000	392,152	$41,892.33	$28,387.88	$13,504.45	$41,386.45	$28,387.88	$12,998.57	($505.88)	-1.2%
	1,500	588,229	$63,134.96	$42,581.90	$20,553.06	$62,376.14	$42,581.90	$19,794.24	($758.82)	-1.2%
	3,000	1,176,457	$126,862.58	$85,163.72	$41,698.86	$125,344.95	$85,163.72	$40,181.23	($1,517.63)	-1.2%
	5,000	1,960,762	$211,832.83	$141,939.56	$69,893.27	$209,303.44	$141,939.56	$67,363.88	($2,529.39)	-1.2%
AVG.USE	1,506	590,581	$63,389.79	$42,752.16	$20,637.63	$62,627.94	$42,752.16	$19,875.78	($761.85)	-1.2%

Current

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	

	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	" "
TRANSITION RATE ADJ	-0.033	-0.033	-0.033	
DISTRIBUTION ADJ	0.503	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	

Proposed

LARGE GENERAL TOU RATE G-3 (13.8 KV)

DELIVERY SERVICES:

		< 100 KVA	> 100 KVA	
CUSTOMER			$90.00	PER BILL
DISTRIBUTION (DEMAND)		$0.00	$4.32	PER KVA
TRANSITION		$0.00	$0.00	
TRANSMISSION		$2.73	$5.24	

	PEAK 26.13%	LOW A 25.46%	LOW B 48.41%	
TRANSITION (ENERGY)	0.387	0.387	0.387	" "
TRANSITION RATE ADJ	(0.033)	(0.033)	(0.033)	" "
DISTRIBUTION ADJ	0.374	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	0.050	" "
SUPPLIER SERVICES:				
DEFAULT SERVICE - FIXED	7.185	7.185	7.185	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL - OPTIONAL - TOU RATE G-4

LF = CUM % BILLS	AVERAGE 0.535 MONTHLY KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	1	267	$44.91	$19.83	$25.08	$44.57	$19.83	$24.74	($0.34)	-0.8%
20	6	2,278	$275.45	$169.16	$106.29	$272.51	$169.16	$103.35	($2.94)	-1.1%
30	7	2,895	$340.82	$214.98	$125.84	$337.08	$214.98	$122.10	($3.74)	-1.1%
40	10	3,784	$450.68	$281.00	$169.68	$445.80	$281.00	$164.80	($4.88)	-1.1%
50	15	5,881	$688.93	$436.72	$252.21	$681.34	$436.72	$244.62	($7.59)	-1.1%
59	32	12,599	$1,462.09	$935.60	$526.49	$1,445.83	$935.60	$510.23	($16.26)	-1.1%
70	43	17,084	$1,974.74	$1,268.66	$706.08	$1,952.70	$1,268.66	$684.04	($22.04)	-1.1%
79	61	24,418	$2,813.16	$1,813.28	$999.88	$2,781.67	$1,813.28	$968.39	($31.49)	-1.1%
90	91	36,039	$4,156.56	$2,676.26	$1,480.30	$4,110.07	$2,676.26	$1,433.81	($46.49)	-1.1%
AVG.USE	36	14,299	$1,654.70	$1,061.84	$592.86	$1,636.25	$1,061.84	$574.41	($18.45)	-1.1%

Current

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

	PEAK	OFF PK	
CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	
	25.04%	74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	
DISTRIBUTION ADJ	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE - FIXED	7.372	7.372	7.372
DEFAULT SERVICE - ADDER	0.054	0.054	0.054

Proposed

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

	PEAK	OFF PK	
CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	
	25.04%	74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - FIXED	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL - OPTIONAL - TOU RATE G-4

LF = CUM % BILLS	HIGH 0.635 MONTHLY KW	KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10	1	267	$44.91	$19.83	$25.08	$44.57	$19.83	$24.74	($0.34)	-0.8%
20	5	2,278	$265.39	$169.16	$96.23	$262.45	$169.16	$93.29	($2.94)	-1.1%
30	6	2,895	$330.76	$214.98	$115.78	$327.02	$214.98	$112.04	($3.74)	-1.1%
40	8	3,784	$430.56	$281.00	$149.56	$425.68	$281.00	$144.68	($4.88)	-1.1%
50	12	5,881	$658.75	$436.72	$222.03	$651.16	$436.72	$214.44	($7.59)	-1.2%
59	27	12,599	$1,411.79	$935.60	$476.19	$1,395.53	$935.60	$459.93	($16.26)	-1.2%
70	36	17,084	$1,904.32	$1,268.66	$635.66	$1,882.28	$1,268.66	$613.62	($22.04)	-1.2%
79	52	24,418	$2,722.62	$1,813.28	$909.34	$2,691.13	$1,813.28	$877.85	($31.49)	-1.2%
90	76	36,039	$4,005.66	$2,676.26	$1,329.40	$3,959.17	$2,676.26	$1,282.91	($46.49)	-1.2%
AVG.USE	30	14,299	$1,594.34	$1,061.84	$532.50	$1,575.89	$1,061.84	$514.05	($18.45)	-1.2%

Current

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

	PEAK	OFF PK	
CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	
	25.04%	74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	
DISTRIBUTION ADJ	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE - FIXED	7.372	7.372	7.372
DEFAULT SERVICE - ADDER	0.054	0.054	0.054

Proposed

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

	PEAK	OFF PK	
CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	
	25.04%	74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "
SUPPLIER SERVICES:			
DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - FIXED	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL - OPTIONAL - TOU RATE G-4

LF =	LOW 0.435			Current			Proposed		DIFFERENCE	
CUM % BILLS	MONTHLY KW	KWH	TOTAL	SUPPLIER	DELIVERY	TOTAL	SUPPLIER	DELIVERY	AMOUNT	%
10	1	267	$44.91	$19.83	$25.08	$44.57	$19.83	$24.74	($0.34)	-0.8%
20	7	2,278	$285.51	$169.16	$116.35	$282.57	$169.16	$113.41	($2.94)	-1.0%
30	9	2,895	$360.94	$214.98	$145.96	$357.20	$214.98	$142.22	($3.74)	-1.0%
40	12	3,784	$470.80	$281.00	$189.80	$465.92	$281.00	$184.92	($4.88)	-1.0%
50	18	5,881	$719.11	$436.72	$282.39	$711.52	$436.72	$274.80	($7.59)	-1.1%
59	39	12,599	$1,532.51	$935.60	$596.91	$1,516.25	$935.60	$580.65	($16.26)	-1.1%
70	53	17,084	$2,075.34	$1,268.66	$806.68	$2,053.30	$1,268.66	$784.64	($22.04)	-1.1%
79	75	24,418	$2,954.00	$1,813.28	$1,140.72	$2,922.51	$1,813.28	$1,109.23	($31.49)	-1.1%
90	111	36,039	$4,357.76	$2,676.26	$1,681.50	$4,311.27	$2,676.26	$1,635.01	($46.49)	-1.1%
AVG.USE	44	14,299	$1,735.18	$1,061.84	$673.34	$1,716.73	$1,061.84	$654.89	($18.45)	-1.1%

Current

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	

	PEAK 25.04%	OFF PK 74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	
DISTRIBUTION ADJ	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	7.372
DEFAULT SERVICE - ADDER	0.054	0.054	0.054

Proposed

SMALL GENERAL TOU RATE G-4

DELIVERY SERVICES:

CUSTOMER		$10.92	PER BILL
DISTRIBUTION (DEMAND)		$4.16	PER KW
TRANSITION		$0.00	
TRANSITION RATE ADJ		$0.00	
TRANSMISSION		$5.90	

	PEAK 25.04%	OFF PK 74.96%	
DISTRIBUTION (ENERGY)	1.100	1.100	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - FIXED	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
COMMERCIAL SPACE HEATING RATE G-5

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		309	$42.90	$22.95	$19.95	$42.50	$22.95	$19.55	($0.40)	-0.9%
20		795	$99.04	$59.04	$40.00	$98.02	$59.04	$38.98	($1.02)	-1.0%
30		1,287	$155.87	$95.57	$60.30	$154.21	$95.57	$58.64	($1.66)	-1.1%
40		2,173	$258.23	$161.37	$96.86	$255.42	$161.37	$94.05	($2.81)	-1.1%
50		2,965	$349.72	$220.18	$129.54	$345.89	$220.18	$125.71	($3.83)	-1.1%
60		4,051	$475.17	$300.83	$174.34	$469.95	$300.83	$169.12	($5.22)	-1.1%
70		5,993	$710.22	$445.04	$265.18	$702.48	$445.04	$257.44	($7.74)	-1.1%
80		11,866	$1,451.98	$881.17	$570.81	$1,436.67	$881.17	$555.50	($15.31)	-1.1%
90		33,578	$4,194.20	$2,493.50	$1,700.70	$4,150.88	$2,493.50	$1,657.38	($43.32)	-1.0%
AVG.USE		15,520	$1,913.48	$1,152.52	$760.96	$1,893.46	$1,152.52	$740.94	($20.02)	-1.0%

Current

COMMERCIAL SPACE HEATING RATE G-5

DELIVERY SERVICES:

	< 5000 KWH	> 5000 KWH	
CUSTOMER		$7.20	PER BILL
DISTRIBUTION (ENERGY)	1.834	2.392	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	1.855	2.375	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	7.372
DEFAULT SERVICE - ADDER	0.054	0.054	0.054

Proposed

COMMERCIAL SPACE HEATING RATE G-5

DELIVERY SERVICES:

	< 5000 KWH	> 5000 KWH	
CUSTOMER		$7.20	PER BILL
DISTRIBUTION (ENERGY)	1.834	2.392	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	1.855	2.375	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	" "

CAMBRIDGE ELECTRIC LIGHT COMPANY
TYPICAL BILL ANALYSIS
SMALL GENERAL - OPTIONAL - TOU RATE G-6 (NON-DEMAND)

CUM % BILLS	KW	MONTHLY KWH	Current TOTAL	Current SUPPLIER	Current DELIVERY	Proposed TOTAL	Proposed SUPPLIER	Proposed DELIVERY	DIFFERENCE AMOUNT	DIFFERENCE %
10		49	$14.82	$3.64	$11.18	$14.76	$3.64	$11.12	($0.06)	-0.4%
20		106	$22.50	$7.87	$14.63	$22.36	$7.87	$14.49	($0.14)	-0.6%
30		184	$33.00	$13.66	$19.34	$32.76	$13.66	$19.10	($0.24)	-0.7%
40		289	$47.14	$21.46	$25.68	$46.77	$21.46	$25.31	($0.37)	-0.8%
50		430	$66.13	$31.93	$34.20	$65.58	$31.93	$33.65	($0.55)	-0.8%
60		593	$88.09	$44.04	$44.05	$87.33	$44.04	$43.29	($0.76)	-0.9%
70		825	$119.33	$61.26	$58.07	$118.27	$61.26	$57.01	($1.06)	-0.9%
80		1,149	$162.97	$85.32	$77.65	$161.49	$85.32	$76.17	($1.48)	-0.9%
90		1,702	$237.45	$126.39	$111.06	$235.26	$126.39	$108.87	($2.19)	-0.9%
AVG.USE		810	$117.31	$60.15	$57.16	$116.27	$60.15	$56.12	($1.04)	-0.9%

Current

SMALL GENERAL TOU RATE G-6 (NON-DEMAND)

DELIVERY SERVICES:

	PEAK 29.49%	OFF-PEAK 70.51%	
CUSTOMER		$8.22	PER BILL
DISTRIBUTION	6.403	2.395	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	6.879	0.000	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.503	0.503	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	

Proposed

SMALL GENERAL TOU RATE G-6 (NON-DEMAND)

DELIVERY SERVICES:

	PEAK 29.49%	OFF-PEAK 70.51%	
CUSTOMER		$8.22	PER BILL
DISTRIBUTION	6.403	2.395	CENTS/KWH
TRANSITION	-0.366	-0.366	" "
TRANSMISSION	6.879	0.000	" "
TRANSITION RATE ADJ	0.000	0.000	" "
DISTRIBUTION ADJ	0.374	0.374	" "
DEFAULT SERV ADJ	0.000	0.000	" "
DEMAND-SIDE MGT	0.250	0.250	" "
RENEWABLE ENERGY	0.050	0.050	" "

SUPPLIER SERVICES:

DEFAULT SERVICE - FIXED	7.372	7.372	CENTS/KWH
DEFAULT SERVICE - ADDER	0.054	0.054	" "

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.01 Purpose

The purpose of the Long-Term Renewable Contract Adjustment Mechanism is to provide NSTAR Electric Company ("NSTAR" or the "Company") a mechanism to adjust, on an annual basis and subject to the jurisdiction of the Department of Public Utilities (the "Department"), its rates for customers of distribution service to recover costs associated with Long-Term Renewable Contracts that are in place to satisfy the requirements of the Green Communities Act (St. 2008, c. 169, s. 83, s. 83A).

1.02 Applicability

This Long-Term Renewable Contract Adjustment Mechanism shall be applicable to NSTAR Electric and all firm electricity, as measured in kilowatt-hours ("kWhs"), delivered by the Company unless otherwise designated.

1.03 Effective Date of Annual Adjustment Factor

The date on which the annual Long-Term Renewable Contract Adjustment Factor ("LTRCA") becomes effective shall be the first day of each calendar year, unless otherwise ordered by the Department. The Company shall submit LTRCA filings as outlined in Section 1.06 of this tariff at least 45 days before the filing is to take effect.

1.04 Definitions

The following terms shall be used in this tariff as defined in this section, unless the context requires otherwise.

(1) "Distribution Company" or "Company" is NSTAR Electric Company.

(2) "Year" is the 12-month period for which the LTRCAF will apply

(3) "Prior Year" is the 12-month period prior to the Year

(4) "Remuneration" is the annual remuneration for the Company equal to 4 per cent or 2.75 per cent of the annual payments under the Long-Term Renewable Contracts. The 4 per cent remuneration applies to contracts subject to Section 83 of the Green Communities Act. The 2.75 per cent remuneration applies to contracts subject to Section 83A of the Green Communities Act

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.05 Long-Term Renewable Contract Adjustment Factor Formula

LTRCAF = (LTRC - MR + PPRA)/FkWh

LTRCAF = The annual Long-Term Renewable Contract Adjustment Factor.

LTRC = The estimated Long-Term Renewable Contract expenditures for Year$_x$. This would include the cost of Energy, Capacity and Renewable Energy Credits ("RECs") and the 4 percent or 2.75 percent Remuneration.

MR = The Market Recovery, for Year$_x$ is the estimate of the sum of: (1) the market value of Energy products produced by the long-term renewable contract(s) and sold at a price equal to the ISO-NE Real Time energy market price; (2) the market value of Capacity products produced by the long-term renewable contract(s) and sold on the ISO-NE Forward Capacity Market; and (3) the market value of the Class I Renewable Energy Credits produced by the long-term renewable contract(s) established by the Company through competitive procurements and used for Basic Service or if not needed for Basic Service, the market value for the RECs sold into the market.

PPRA = The Past Period Reconciliation Amount is the sum of: (a) the difference between (1) the amount of actual Long-Term Renewable Contract product expenditures plus the amount of actual Remuneration earned less the amount of actual Market Recovery of the Long-Term Renewable Contract products accumulated by the Company in Prior Year(s); and (2) the amount of LTRCA revenue actually received by the Company in Prior Year(s); and (b) the amount computed in clause (a) times the prime rate computed in accordance with 220 C.M.R. § 6.08(2).

FkWh = The Forecasted kWhs is the forecasted amount of electricity to be distributed to the Company's distribution customers for the Year.

1.06 Information Required to be Filed with the Department

Information pertaining to the Long-Term Renewable Contract Adjustment Mechanism shall be filed with the Department as part of the Company's annual electric reconciliation filing at least thirty (45) days before the date on which a new LTRCA is to be effective. Additionally, the Company will file with the Department a complete list by (sub)account of all Long-Term Renewable Contract accounts claimed as recoverable through the LTRCA over the relevant calendar year. This information will be submitted with each annual LTRCA filing, along with complete documentation of the reconciliation-adjustment calculations.

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.07 Customer Notification

The Company will notify customers in simple terms of changes to the LTRCA, including the nature of the change and the manner in which the LTRCA is applied to the bill. In the absence of a standard format, the Company will submit this notice for approval at the time of each LTRCA filing. Upon approval by the Department, the Company shall immediately distribute these notices to all of its distribution customers either through direct mail or with its bills.

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.01 Purpose

The purpose of the Long-Term Renewable Contract Adjustment Mechanism is to provide NSTAR Electric Company ("NSTAR" or the "Company") a mechanism to adjust, on an annual basis and subject to the jurisdiction of the Department of Public Utilities (the "Department"), its rates for customers of distribution service to recover costs associated with Long-Term Renewable Contracts that are in place to satisfy the requirements of the Green Communities Act (St. 2008, c. 169, s. 83, s. 83A).

1.02 Applicability

This Long-Term Renewable Contract Adjustment Mechanism shall be applicable to NSTAR Electric and all firm electricity, as measured in kilowatt-hours ("kWhs"), delivered by the Company unless otherwise designated.

1.03 Effective Date of Annual Adjustment Factor

The date on which the annual Long-Term Renewable Contract Adjustment Factor ("LTRCA") becomes effective shall be the first day of each calendar year, unless otherwise ordered by the Department. The Company shall submit LTRCA filings as outlined in Section 1.06 of this tariff at least 45 days before the filing is to take effect.

1.04 Definitions

The following terms shall be used in this tariff as defined in this section, unless the context requires otherwise.

(1) "Distribution Company" or "Company" is NSTAR Electric Company.

(2) "Year" is the 12-month period for which the LTRCAF will apply

(3) "Prior Year" is the 12-month period prior to the Year

(4) "Remuneration" is the annual remuneration for the Company equal to 4 per cent or 2.75 per cent of the annual payments under the Long-Term Renewable Contracts. The 4 per cent remuneration applies to contracts subject to Section 83 of the Green Communities Act. The 2.75 per cent remuneration applies to contracts subject to Section 83A of the Green Communities Act

Deleted: A
Formatted: Font: (Default) Times New Roman, 11 pt
Formatted: Font: (Default) Times New Roman, 11 pt
Formatted: Font: (Default) Times New Roman, 11 pt
Formatted: Bullets and Numbering
Deleted: Thomas J. May
Deleted: Dec
Deleted: 4
Deleted: 2
Deleted: 3

Deleted: A

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.05 Long-Term Renewable Contract Adjustment Factor Formula

Deleted: ¶
¶
¶
¶
¶

LTRCAF = (LTRC - MR + PPRA)/FkWh

LTRCAF = The annual Long-Term Renewable Contract Adjustment Factor.

LTRC = The estimated Long-Term Renewable Contract expenditures for Year$_x$. This would include the cost of Energy, Capacity and Renewable Energy Credits ("RECs") and the 4 percent or 2.75 percent Remuneration.

MR = The Market Recovery, for Year$_x$ is the estimate of the sum of: (1) the market value of Energy products produced by the long-term renewable contract(s) and sold at a price equal to the ISO-NE Real Time energy market price; (2) the market value of Capacity products produced by the long-term renewable contract(s) and sold on the ISO-NE Forward Capacity Market; and (3) the market value of the Class I Renewable Energy Credits produced by the long-term renewable contract(s) established by the Company through competitive procurements and used for Basic Service or if not needed for Basic Service, the market value for the RECs sold into the market.

PPRA = The Past Period Reconciliation Amount is the sum of: (a) the difference between (1) the amount of actual Long-Term Renewable Contract product expenditures plus the amount of actual Remuneration earned less the amount of actual Market Recovery of the Long-Term Renewable Contract products accumulated by the Company in Prior Year(s); and (2) the amount of LTRCA revenue actually received by the Company in Prior Year(s); and (b) the amount computed in clause (a) times the prime rate computed in accordance with 220 C.M.R. § 6.08(2).

FkWh = The Forecasted kWhs is the forecasted amount of electricity to be distributed to the Company's distribution customers for the Year.

1.06 Information Required to be Filed with the Department

Information pertaining to the Long-Term Renewable Contract Adjustment Mechanism shall be filed with the Department as part of the Company's annual electric reconciliation filing at least thirty (45) days before the date on which a new LTRCA is to be effective. Additionally, the Company will file with the Department a complete list by (sub)account of all Long-Term Renewable Contract accounts claimed as recoverable through the LTRCA over the relevant calendar year. This information will be submitted with each annual LTRCA filing, along with complete documentation of the reconciliation-adjustment calculations.

Deleted: Thomas J. May
Deleted: Dec
Deleted: 4
Deleted: 2
Deleted: 3

Deleted: A

LONG-TERM RENEWABLE CONTRACT ADJUSTMENT MECHANISM

RATE LTRCA

1.07 Customer Notification

The Company will notify customers in simple terms of changes to the LTRCA, including the nature of the change and the manner in which the LTRCA is applied to the bill. In the absence of a standard format, the Company will submit this notice for approval at the time of each LTRCA filing. Upon approval by the Department, the Company shall immediately distribute these notices to all of its distribution customers either through direct mail or with its bills.

Deleted: Thomas J. May
Deleted: Dec
Deleted: 4
Deleted: 2
Deleted: 3

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of NSTAR Electric Company for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	))))	D.P.U. 13-148
Petition of Western Massachusetts Electric Company for Approval of Proposed Long-Term Contracts for Renewable Energy Pursuant to St. 2008, c. 169, § 83A	))))	D.P.U. 13-149

AFFIDAVIT OF RICHARD D. CHIN

Richard D. Chin does hereby depose and say as follows:

I, Richard D. Chin, certify that the attached joint testimony and accompanying exhibits, on behalf of NSTAR Electric Company and Western Massachusetts Electric Company, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 20th day of September, 2013.

Richard D. Chin

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Fitchburg Gas and Electric Light Company) Company d/b/a Unitil) for Approval of Proposed Long-Term) Contracts for Renewable Energy Pursuant to) St. 2008, c. 169, § 83A)	D.P.U. 13-146
Petition of Massachusetts Electric Company and) Nantucket Electric Company d/b/a National Grid) for Approval of Proposed Long-Term) Contracts for Renewable Energy Pursuant to) St. 2008, c. 169, § 83A)	D.P.U. 13-147
Petition of NSTAR Electric Company) for Approval of Proposed Long-Term) Contracts for Renewable Energy Pursuant to) St. 2008, c. 169, § 83A)	D.P.U. 13-148
Petition of Western Massachusetts Electric) Company for Approval of Proposed Long-Term) Contracts for Renewable Energy Pursuant to) St. 2008, c. 169, § 83A)	D.P.U. 13-149

AFFIDAVIT OF JEFFERY S. WALTMAN

Jeffery S. Waltman does hereby depose and say as follows:

I, Jeffery S. Waltman, certify that the attached joint testimony and accompanying exhibits, on behalf of NSTAR Electric Company and Western Massachusetts Electric Company, which bear my name, were prepared by me or under my supervision and are true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury as of this 20th day of September, 2013.

Jeffery S. Waltman

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company Section 83A Long-term Renewable Contracts	)	D.P.U. 13-148

MOTION OF NSTAR ELECTRIC COMPANY
FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

Now comes NSTAR Electric Company (the "Company") and hereby requests that the Department of Public Utilities (the "Department") grant protection from public disclosure of certain confidential, sensitive and proprietary information submitted in this proceeding in accordance with G.L. c. 25, § 5D and 220 CMR § 1.04(5)(e). Specifically, the Company requests that the Department protect from public disclosure information contained in the following exhibits:

- Exhibit JU-1 through Exhibit JU-6;
- Exhibit JU-8 through Exhibit JU-12; and
- the Company's filed Workpaper Support, Tabs C, D, E, F and G
- Exhibit-NSTAR-RDC-1

(hereinafter the "Confidential Exhibits"). As discussed below, the Confidential Exhibits contain proprietary and competitively sensitive information about the pricing and terms of proposals submitted by third parties that, if released publicly, could harm the competitive business position of the Company, its contract counterparties and its customers.

I. LEGAL STANDARD

The Department is authorized to protect from public disclosure "trade secrets, confidential, competitively sensitive or other proprietary information provided in the course of proceedings." G.L. c. 25, § 5D. The Department has developed a three-part standard for assessing requests for protective treatment submitted pursuant to c. 25, § 5D.

First, the information for which protection from disclosure is sought must constitute "trade secrets, [or] confidential, competitively sensitive or other proprietary information." Second, the party seeking protection from disclosure must overcome the statutory presumption that the public is benefited by disclosure of that information by "proving" the need for non-disclosure. Finally, the Department will protect only so much of the information as is necessary to meet the established need. See, e.g., Western Massachusetts Electric Company, D.T.E. 99-56 (1999); Dispatch Communications of New England d/b/a Nextel Communications, Inc., D.P.U. 95-59-B/95-80/95-112/96-13, September 2, 1997 Procedural Order. Appropriate considerations with respect to the public interest issue include an assessment of the interests at stake, the likely harm that would result from public disclosure of information, and the public policy implications of such disclosure. See, e.g., Berkshire Gas Company, D.P.U. 93-187/188/189/190 (1994); Boston Gas Company, D.P.U. 92-259 (1993), Essex County Gas Company, D.P.U. 96-105 (1996).

II. BASIS FOR CONFIDENTIALITY

The Confidential Exhibits should be protected by the Department and remain confidential because they contain competitively sensitive bid terms and contract pricing information. Specifically, the Confidential Exhibits contain references to: (1) bid terms that the Company received and reviewed as a result of a competitive solicitation of proposals for long-term renewable energy generation pursuant to St. 2008, c. 169, § 83A; (2) contract pricing and related terms for the contracts that are subject to approval in this proceeding; and (3) a proprietary forecast of energy prices provided to the Company by a consultant for evaluation of the bids. Information contained in the following exhibits fall into these categories:

<u>Bid Terms Received and Reviewed</u>

- Exhibit JU-8 (Summary of Company Bid Analysis of all bids received);
- Exhibit JU-9 (Summary of Company Bid Analysis on Non-price factors);
- Exhibit JU-10 (Summary of Company Bid Analysis, selection of Short List);
- Exhibit JU-11 (Summary of Company Bid Analysis, refreshed Short List);
- Workpaper Support, Tabs D and E (Company spreadsheet bid analysis model).

<u>Contract Price and Related Terms</u>

- Exhibits JU-1 through JU-6 (Contracts);
- Workpaper Support, Tab C (Complete bid packages as received);
- Workpaper Support, Tabs F and G (redline versions of Contracts);
- Exhibit NSTAR-RDC-1 (Contract Cost Information Used to Develop Rates).

<u>Proprietary Forecast of Energy Prices</u>

- Exhibit JU-12 (ESAI Market Price Forecast)

A. The Department Should Protect Bid Terms Received and Reviewed by the Company and the Contract Price and Price Terms in the Contracts Subject to Review in this Proceeding

The Department should protect the bid information received by the Company as result of its Request for Proposals ("RFP") relating to this proceeding and the Company's analysis of those bids, as well as the contract prices and price terms in the contract subject to review in this proceeding. Exhibits JU-8, JU-9, JU-10 and JU-11 are summaries of the bid evaluations that contain information regarding the names of bidders responding to the Company's RFP, their respective bids, bid terms, and the Company's evaluation of such bids. Workpaper Support, Tabs D and E (on CD-ROM) are Excel files of the Company's bid analysis spreadsheet model used to evaluate the bids. Workpaper Support, Tab C is a copy of each bid package as received from the bidder. Exhibits JU-1 through Exhibit JU-6 are copies of the six contracts subject to review in this proceeding. Workpaper Support Tabs D and E are the executed contracts redlined against the Model PPA showing changes from the Model PPA. Finally, Exhibit NSTAR-RDC-1 includes contract cost information and is used to develop the Company's estimate of cost recovery through its Long Term Renewable Contract Adjustment Tariff.

It is important that the above-referenced bid-related information and contract price terms be held confidential because its disclosure could harm financially the parties that participated in the RFP process, as well as the interests of the Company's customers in other competitive solicitations. The Company has treated the names of bidders, bid information and bid analysis as confidential throughout the RFP process. This information has been tightly controlled and has not been distributed outside of the Company or the Company's counsel and jurisdictional regulatory agencies that have executed non-disclosure agreements with the Company. All bidders were told that the RFP process would be conducted in a highly confidential manner. The process was designed this way to encourage participation, promote competition in the bidding process, and maximize the value of the bids received. Any disclosure now could significantly damage the RFP process.

Moreover, if the bid-related information or contract price terms are disclosed, the effectiveness and competitiveness of competitive solicitations for renewable generation will be harmed substantially. Indeed, if the bid information in the Confidential Exhibits is released, it may make bidders more reluctant to submit bids in future solicitations to the extent they wish to submit bids confidentially, or may inflate bids that might otherwise be submitted based on a respondent's review of the Company's bid information received to date. Thus, the release of the bid information at this time would potentially prejudice the continuing RFP process for renewable generation and ultimately harm the Company's customers.

The Department has protected bid information from public disclosure historically, because the public release of terms discloses the very types of information that the Department has previously and consistently held to be confidential. See, e.g., NSTAR Electric Company, D.T.E. 04-60 (March 14, 2005 Hearing Officer Memorandum); see also NSTAR Electric Company, D.T.E. 07-64 (November 19, 2007 Hearing Officer Memorandum); NSTAR Electric Company, D.P.U. 11-05/ 11-06/ 11-07. The Department has recognized that release of bid information, in particular, would seriously undermine the Company's negotiating position in the market, and thus, jeopardize the ability of the Company to ensure that customers are being served by the lowest cost option. See, e.g., Western Massachusetts Electric Company, D.T.E. 99-101, at 3 (2002), citing Boston Edison Company, D.T.E. 99-16 (1999); Western Massachusetts Electric Company, D.T.E. 99-56 (1999). See also Canal Electric Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E. 02-34 (Tr. A at 19 (June 12, 2002)) and Cambridge Electric Light Company, D.T.E. 01-94 (May 9, 2002 Approval by the Department of Amended Motion of Cambridge Electric Light Company for a Protective Order). Accordingly, the Department should protect the bid information found in the above-referenced exhibits from the public record.

B Energy Price Forecast Information

With regard to Exhibit JU-12, the release of this exhibit to the public would compromise the ability of the Company to negotiate future purchase-power contracts. The Department has protected market forecast information associated with electricity contracts from the public record in the past. See, e.g., NSTAR Electric Company, D.T.E. 04-60 (March 14, 2005 Hearing Officer Memorandum); see also NSTAR Electric Company, D.T.E. 07-64 (November 19, 2007 Hearing Officer Memorandum). The market forecast data is considered proprietary by the consultant that produced it. More importantly, however, these projections must be protected from public disclosure because the Company has used this information to evaluate bids associated with the RFP process described herein, and may continue to use this forecast to evaluate future bids for renewable generation services. If other parties had access to the details of Exhibit JU-12 and the assumptions regarding future energy prices contained therein, the Company's ability to negotiate the best deals possible on behalf of customers would be compromised. Accordingly, the Department should protect the energy forecast information in Exhibit JU-12 from the public record.

III. CONCLUSION

WHEREFORE, for the reasons stated above, the Company respectfully requests that the Department grant its motion to protect from public disclosure confidential, competitively sensitive and proprietary information contained in the Confidential

Exhibits. To the Company's knowledge, information in the Confidential Exhibits is not otherwise available in the public domain.

The Company proposes that this information be protected from public disclosure for a period of three years, consistent with recent Department practice.

Respectfully submitted,

NSTAR ELECTRC COMPANY

By its attorneys,

Donald W. Boecke

Danielle Winter, Esq.
Donald W. Boecke, Esq.
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400

Dated: September 20, 2013

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

NSTAR Electric Company Section 83A Long-term Renewable Contracts	)	D.P.U. 13-148

APPEARANCE OF COUNSEL

In the above-referenced proceeding, we hereby appear for and on behalf of NSTAR Electric Company.

Donald W. Boecke, Esq.
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400
dboecke@keeganwerlin.com

Danielle C. Winter , Esq.
Keegan Werlin LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400
dwinter@keeganwerlin.com

Dated: September 20, 2013