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February 12, 2016

M. Kathryn Sedor, Presiding Officer
Energy Facilities Siting Board
One South Station
Boston, MA 02110

Re: NSTAR Electric Company d/b/a Eversource Energy, EFSB 14-04/ D.P.U. 14-153/14-154

Dear Ms. Sedor:

Enclosed please find an original and four copies of the responses of NSTAR Electric Company d/b/a Eversource Energy to the 20 Record Requests issued by the Energy Facilities Siting Board on January 6 and 7, 2016 in the above-referenced proceeding.

The response to Record Request RR-EFSB-1contains confidential, proprietary customer information. Accordingly, this information has been redacted for the public record in order to avoid disclosure. A Motion for Protective Treatment is also included with this filing. The Company is submitting four **CONFIDENTIAL** (non-redacted) copies of the response under seal.

Also enclosed is a certificate of service.

Thank you for your attention to this matter.

Very truly yours,

Catherine Keuthen

Catherine Keuthen

Enclosures

COMMONWEALTH OF MASSACHUSETTS
ENERGY FACILITIES SITING BOARD

NSTAR Electric Company d/b/a Eversource Energy	))))	EFSB 14-04/D.P.U. 14-153/154

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to 980 C.M.R. 1.03(4), I have on or before this day served a true copy of the enclosed documents, by first class mail or electronically, upon all parties of record in this proceeding.

Dated at Boston, Massachusetts this 12th day of February, 2016.

Catherine Keuthen

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Boston, MA 02110
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COMMONWEALTH OF MASSACHUSETTS
ENERGY FACILITIES SITING BOARD

NSTAR Electric Company, d/b/a Eversource Energy	))))	EFSB 14-04 / D.P.U. 14-153/154

MOTION FOR PROTECTIVE TREATMENT OF CONFIDENTIAL, PROPRIETARY AND NONPUBLIC INFORMATION

I. INTRODUCTION

Now comes NSTAR Electric Company, d/b/a Eversouce Energy ("Eversource" or the "Company") and hereby requests that the Energy Facilities Siting Board (the "Siting Board") grant protection from public disclosure, in accordance with G.L. c. 25, § 5D, confidential, proprietary and nonpublic information submitted in this proceeding. Specifically, the Company requests that the Siting Board protect from public disclosure certain confidential and proprietary information specific to Eversource's customer, the Massachusetts Port Authority ("MassPort") and concerning Logan Airport, that is not in the public record and that is responsive to Record Request EFSB-RR-1, as filed today in this proceeding. Pursuant to Siting Board and Department of Public Utilities precedent, customer-specific information is proprietary to the customer and only that customer has the right to indicate whether his or her information should be available to anyone else or to the public in general. Therefore, the Company seeks protection for the customer-specific information as provided in the Company's response to EFSB-RR-1.

II. LEGAL STANDARD

Confidential information may be protected from public disclosure in accordance with G.L. c. 25, § 5D, which states in part that:

> The [D]epartment may protect from public disclosure, trade secrets, confidential, competitively sensitive or other proprietary information provided in the course of proceedings conducted pursuant to this chapter. There shall be a presumption that the information for which such protection is sought is public information and the burden shall be on the proponent of such protection to prove the need for such protection. Where the need has been found to exist, the [D]epartment shall protect only so much of the information as is necessary to meet such need.

In past decisions, the Department has found that customer-specific information is proprietary to the customer and that each customer has the right to control the dissemination of his or her account information. Bay State Gas Company, D.P.U. 06-36, at 5 (Hearing Officer Ruling on Motions for Confidentiality, January 18, 2007). In that case, the Department granted Bay State Gas Company's request to protect customer-specific information and maintained that this type of information is sensitive and proprietary and is of the type of information that is appropriate to protect from the public pursuant to G.L. c. 25, § 5D. Id.

III. BASIS FOR CONFIDENTIAL TREATMENT

The confidential information contained in the Company's response to EFSB-RR-1 provides customer-specific information, including: Logan Airport's peak demand, the amount of installed emergency generation it has to support the necessary life, safety and security functions, and the impacts on the Airport in the event of an N-1-1 contingency. This information is treated as confidential within the Company and is not disseminated outside the Company**.** Moreover, the Department has recognized each customer's right to control dissemination of his or her account information, address, load and demand information and payment records. Such customer-specific information is proprietary to the customer and only the customer has the right to indicate whether such information should be available in the public domain. See Bay State Gas Company, D.P.U. 06-36, at 5. Consistent with this precedent, the Company seeks protection for certain customer-specific information that is confidential, commercially sensitive, and proprietary from public disclosure. This material, therefore, must remain confidential to preserve the Company's customers' privacy interests.

IV. CONCLUSION

For the reasons cited above, the Company maintains that the customer-specific information, as provided in the Company's response to EFSB-RR-1, is confidential, proprietary to MassPort, and nonpublic. As such, disclosure on the public record of those materials would be detrimental to the named customer and would compromise its privacy rights. Accordingly, the information should be protected from public disclosure indefinitely in accordance with G.L. c. 25, § 5D, as the customer's privacy rights are not subject to an expiration date or an end of a contractual expectation of privacy.

Respectfully submitted,

NSTAR ELECTRIC COMPANY d/b/a
EVERSOURCE ENERGY

By its attorneys,

Catherine Keuthen

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Catherine J. Keuthen
Cheryl A. Blaine
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(617) 951-1400

Dated: February 12, 2016

REDACTED

NSTAR Electric Company d/b/a Eversource Energy
Energy Facilities Siting Board
EFSB 14-04/D.P.U. 14-153/14-154
Information Request: **EFSB-RR-1**
February 12, 2016
Person Responsible: Richard C. Zbikowski

Information Request EFSB-RR-1 (Tr. 1, at 35)

Please provide the following information: (a) the size of the electric load for Logan International Airport ("Airport"); (b) whether the Airport has backup generation available; (c) the Company's position on its obligation to serve the Airport regardless of the availability of backup generation; and (d) particular impacts on the Airport in the event of an N-1-1 contingency.

Response

a) Based on a five year meter history (2011-2015), the peak demand for Logan Airport was [redacted] MVA.

b) Logan Airport has installed [redacted] MW of emergency generation to support necessary life, safety and security functions. [redacted]

c) The Company has an obligation to provide service to the Massachusetts Port Authority ("MassPort"), the owner and operator of Logan Airport, under a Wholesale Distribution Service Agreement and a Local Service Agreement under Schedule 21-NSTAR of the ISO New England Inc. Open Access Transmission Tariff.)

Article 3.1 of the Wholesale Distribution Service Agreement defines the scope of service as follows:

> "The Company will provide Distribution Service [defined as the delivery of energy and/or capacity from the Points of Receipt, over the Company's Distribution System, to the Customer at the Points of Delivery] on a basis that is comparable to the Company's use of Distribution System to reliably serve its Native Load Customers. The Company recognizes that the Customer provides essential life safety services to the region [...] and, as such, will provide Distribution Service to the Customer that is at least equivalent to that provided to other essential life safety service customers of the Company. As such, to the extent the Company has control given

REDACTED

> the circumstances then applicable to all or a portion of the NSTAR system and the practicality of the measures then available to the Company as to the sequence that Customer's service will be interrupted and/or restored, the Customer's service shall be among the last to be interrupted and among the first to be restored, similar to other essential life safety service customers, such as hospitals and public safety facilities".

A copy of the Wholesale Distribution Service Agreement, approved by the Federal Energy Regulatory Commission on March 16, 2010, is provided as Attachment EFSB-RR-1(1).

d) [redacted]

Please note that this response has been redacted to protect the confidential, proprietary and nonpublic nature of the information. These materials have been marked with a “Confidential” designation and are being provided unredacted to the Energy Facilities Siting Board under seal and subject to a motion for protected treatment.

Wholesale Distribution Service Agreement

By and Between

NSTAR Electric Company

and

Massachusetts Port Authority

WHOLESALE DISTRIBUTION SERVICE AGREEMENT

This AGREEMENT ("Agreement"), entered into this 1st day of September, 2005, is by and between NSTAR Electric Company, f/k/a Boston Edison Company, a Massachusetts corporation having a principal place of business at 800 Boylston Street, Boston, Massachusetts ("NSTAR Electric" or the "Company"), and the Massachusetts Port Authority, a body politic and corporate organized and existing pursuant to Chapter 465 of the Acts of 1956, as amended (the "Customer"). The Company and the Customer are sometimes individually referred to herein as a "Party" and collectively as the "Parties."

WHEREAS, the Customer desires to obtain Distribution Service, as defined below, from the Company for the delivery of power purchased from a third-party supplier; and

WHEREAS, the Company and the Customer intend to sign a Local Service Agreement under the Company's Tariff, which will govern, inter alia, the terms and conditions of transmission service over the Company's Transmission System; and

WHEREAS, in consideration of the terms and conditions of the Service Agreement and this Agreement, the Company has agreed to provide Distribution Service to the Customer.

NOW, THEREFORE, the Company and the Customer, in consideration of their respective commitments set forth in this Agreement, covenant and agree as follows:

ARTICLE 1 Definitions

Wherever used in this Agreement with initial capitalization, the following terms shall have the meanings specified or referred to in this Article. Any term not defined herein shall have the meaning set forth in the Company's Tariff or the Interconnection Agreement, as appropriate.

1.1 Annual 13.8 kV Revenue Requirements shall mean the Company's revenue requirements associated with service over the 13.8 kV portion of its Distribution System, calculated in accordance with Attachment A hereto.

1.2 Annual Primary Revenue Requirements shall mean the Company's revenue requirements associated with service over the primary service portion of its Distribution System, which is addressed separately in this Agreement, calculated in accordance with Attachment B hereto.

1.3 Annual True-Up shall mean the reconciliation to actual costs of the estimated costs used for billing purposes under Article 5.0 of this Agreement.

1.4 Company's Tariff shall mean the Company's Schedule 21 of the ISO Tariff and accompanying schedules and attachments, as modified and amended from time to time.

1.5 Curtailment shall mean a reduction in Distribution Service in response to a distribution capacity shortage as a result of system reliability conditions.

1.6 Designated Agent shall mean any entity that performs actions or functions on behalf of the Company or the Customer, as specified herein.

1.7 DTE shall mean the Massachusetts Department of Telecommunications and Energy, or any successor organization.

1.8 Distribution Service shall mean the delivery of energy and/or capacity from the Points of Receipt, over the Distribution System, to the Customer at the Points of Delivery.

1.9 Distribution System shall mean the facilities owned, controlled or operated by the Company that are classified to the distribution function on the chart of FERC accounts of the Company and that are used to provide Distribution Service pursuant to the terms of this Agreement.

1.10 FERC shall mean the Federal Energy Regulatory Commission or any successor agency.

1.11 Force Majeure shall mean any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, earthquake, explosion, breakage or accident to machinery or equipment (not caused by the intentional or negligent act or omission of the Company or the Customer), any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause (excluding a lack of funds or other financial causes) beyond a Party's control, including without limitation, any action or inaction by the other Party.

1.12 Prudent Utility Practice shall mean any of the applicable practices, methods, and acts; (a) required by NEPOOL, NPCC, NERC, ISO, or the successor of any of them, whether or not the Party whose conduct is at issue is a member thereof; (b) required by the reasonable policies and standards of the Company incorporated in the Company's Information and Requirements for Electric Service and the Company's tariffs on file with the DTE, to the extent applicable and not inconsistent with the non-technical terms of this Agreement; or (c) otherwise engaged in or approved by a significant portion of the electric utility industry during the relevant time period; which in the exercise of reasonable judgment in light of the facts that are known or that should have been known at the time a decision was made, could have been expected to accomplish the desired result in a manner, and at a reasonable cost, consistent with law, regulation, good business practices, generation, transmission, and distribution reliability, safety, environmental protection, economy, and expediency. Prudent Utility Practice is intended to be acceptable practices, methods, or acts generally accepted in the region, and is not intended to be limited to the optimum practices, methods, or acts to the exclusion of all others.

1.13 Interconnection Agreement shall mean the Interconnection Agreement between the Company and the Customer, if required.

1.14 ISO shall mean ISO New England Inc., the regional transmission organization for New England, or any successor organization.

1.15 ISO Tariff shall mean the ISO New England Inc. Open Access Transmission Tariff, which is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, and accompanying schedules and attachments, as modified and amended from time to time.

1.16 Load Ratio Share shall mean the ratio of (i) the Customer's hourly metered load coincident with the Company's monthly Distribution System peak to (ii) the Company's monthly Distribution System peak.

1.17 Local Network Service shall mean the transmission service provided under Schedule 21-BEC of the ISO Tariff.

1.18 Monthly Customer Charge shall mean that charge assessed to the Customer pursuant to and calculated in accordance with Section 4.2 herein.

1.19 Monthly Demand Charge shall mean the rate charged to the Customer for Distribution Service under this Agreement, calculated in accordance with Section 4.1 herein.

1.20 Native Load Customers shall mean the wholesale and retail electric customers of the Company on whose behalf the Company, by statute, franchise, regulatory requirement, contract, or otherwise, has undertaken an obligation to construct and operate the Company's Transmission System and Distribution System to meet the reliable electric needs of such customers.

1.21 NERC shall mean the North American Electric Reliability Council, or any successor organization.

1.22 NPCC shall mean the Northeast Power Coordinating Council, or any successor organization.

1.23 OASIS shall mean the Open Access Same-Time Information System.

1.24 Points of Delivery shall mean the points on the Company's Distribution System where capacity and energy distributed by the Company will be made available to the Customer, as specified in Exhibit 1 hereof.

1.25 Points of Receipt shall mean the points of interconnection of the Distribution System with the Transmission System, where capacity and energy will be made available to the Company for delivery across the Distribution System to the Customer.

1.26 Qualified Personnel shall mean individuals trained for their positions pursuant to Prudent Utility Practice.

1.27 Service Agreement shall mean the Service Agreement for Local Network Service under the Company's Tariff executed by the Parties.

1.28 Service Year shall mean the calendar year in which the Customer is receiving service under this Agreement.

1.29 System Emergency shall mean an imminent condition of the Transmission System or Distribution System or on the facilities of the Customer or a neighboring utility of the Company that is likely, in the Company's sole reasonable opinion, to result in significant disruption of service or is likely to endanger life, property, or the environment.

1.30 Transmission System is all facilities of the Company or other companies which are utilized to provide transmission service under the ISO Tariff.

ARTICLE 2 Term

2.1 Service under this Agreement shall become effective on the later of (i) November 1, 2005, or (ii) such other date as it is permitted to become effective by FERC. This Agreement shall continue in effect until superseded by a rate schedule filed at and accepted by the FERC, unless earlier terminated by mutual consent of the parties. Upon termination of this Agreement for any reason, the Company shall file a Notice of Cancellation under Part 35 of FERC's regulations, 18 C.F.R. §§ 35.15 and 131.53 (2000).

2.2 The applicable provisions of this Agreement shall continue in effect after cancellation or termination hereof to the extent necessary to provide for final billings, billing adjustments and payments pertaining to liability and indemnification obligations arising from acts or events that occurred while this Agreement was in effect.

ARTICLE 3 Scope of Service

3.1 The Company will provide Distribution Service on a basis that is comparable to the Company's use of the Distribution System to reliably serve its Native Load Customers. The Company recognizes that the Customer provides essential life safety services to the region at the Points of Delivery noted on Exhibit 1 and, as such, will provide Distribution Service to the Customer that is at least equivalent to that provided to other essential life safety service customers of the Company. As such, to the extent the Company has control given the circumstances then applicable to all or a portion of the NSTAR system and the practicality of the measures then available to the Company as to the sequence that customers' service will be interrupted and/or restored, the Customer's service shall be among the last to be interrupted and among the first to be restored, similar to other essential life safety service customers, such as hospitals and public safety facilities. Such delivery shall be in the form of three (3) phase alternating current at a frequency of approximately sixty (60) Hertz.

3.2 (i) The Customer shall provide the Company with annual updates of a five year forecast of its load. The Customer also shall provide the Company with timely advance notice of material changes in the Customer's load or other aspects of its facilities or operations affecting the Company’s ability to provide reliable service.

(ii) To the extent the Customer desires to add new Points of Delivery, the Customer shall provide the Company with as much advance notice as reasonably practicable. The addition of new Points of Delivery will require modifying Exhibit 1 of this Agreement.

(iii) Infrastructure upgrades may be required if the Customer a) requests additional Point(s) of Delivery, b) requests redundant supply and/or c) experiences significant load growth. In such event, the Customer shall be responsible for all or a portion the cost of additions and/or upgrades to the Distribution System or the Transmission System, pursuant to this Agreement, the Company’s Tariff or FERC regulation, as applicable. If the Customer requests an upgrade to the regional Transmission System, the Customer will be responsible for its allocated share of the cost of any required upgrades pursuant to the ISO Tariff.

(iv) The Company shall notify the Customer of the need for a system impact study to be performed, at the Customer’s expense, to assess the need for infrastructure upgrades required in order to reliably serve the new Point(s) of Delivery or to provide redundant service. In the event infrastructure upgrades need to be constructed, the Customer shall notify the Company of its intent to proceed with the upgrades within thirty (30) days from the date of delivery of the system impact study to the Customer. The Parties shall negotiate payment of the Customer’s allocated share of the cost of the upgrades. Prepayment of the cost of such upgrades will be the subject of a separate agreement between the Company and the Customer to be executed prior to design and construction of the upgrades. The requested incremental service will commence upon the completion of the construction upgrades.

3.3 The Customer shall take steps to execute a Local Service Agreement associated with and, at all times that it takes service under this Agreement, pay for Local Network Service under Schedule 21-BECo of the ISO Tariff, and shall, at its own expense, arrange for (i) the electricity being distributed for the Customer, including allowances for losses, to be accounted for by ISO New England and (ii) all necessary transmission services to deliver said electricity to the Company at the Points of Receipt.

3.4 The Company will plan, construct, operate and maintain its Distribution System in accordance with Prudent Utility Practice, which shall include the terms of the Interconnection Agreement if one is required in order to provide the Customer with Distribution Service over the Company's Distribution System.

3.5 The Distribution Customer shall use Distribution Service only for the Points of Delivery described in Exhibit 1. There are other Massport properties that are not provided for under this Agreement, and shall not be provided Distribution Service hereunder.

3.6 (i) All wiring, poles, pole lines, conductors, conduit, manholes, transformers and other electrical equipment on the Company's side of the Points of Delivery shall be owned, operated, and maintained by the Company. The Customer shall install and maintain suitable protective devices as reasonably required by the Company on the Customer's side of the Points of Delivery in order to afford adequate protection to the Company's equipment against a fault or disturbance originating on the Customer's side of the Points of Delivery. Such protective devices shall be in accordance with Prudent Utility Practice for such equipment.

(ii) The provision of Distribution Service shall be conditioned upon the Customer's constructing, maintaining and operating the facilities, in accordance with Prudent Utility Practice and the terms of the Interconnection Agreement if one is required, on its side of each Point of Delivery necessary to reliably deliver capacity and energy from the Company's Distribution System to the Customer. The Customer shall be solely responsible for constructing or installing all facilities on the Customer's side of each such Point of Delivery, which facilities shall be subject to inspection by the Company upon reasonable notice.

3.7 Losses associated with Distribution Service will be determined by the Company from time to time using a methodology that is consistent with Prudent Utility Practice and which accurately represents the losses between the Points of Receipt and the Points of Delivery. The Company will provide the Customer with all loss determinations and supporting loss calculations in sufficient detail for the Customer to verify their correctness. The Customer is solely responsible for replacing losses associated with Distribution Service, as calculated by the Company.

3.8 The Customer shall not connect any incremental generation to the Customer's side of the Interconnection Points after the execution of this Agreement without first notifying the Company of its desire to connect such generation. The Company shall subsequently notify the Customer whether a system impact study is required to be performed, at the Customer's expense, to assess the need for infrastructure upgrades required as a result of the incremental generation. In the event infrastructure upgrades are required, the Customer must sign an Interconnection Agreement with the Company. Interconnection of the incremental generation shall not occur until the completion of such upgrades.

3.9 The Customer's equipment and any changes to the Customer's equipment shall meet the standards of Prudent Utility Practice. The Company reserves the right to require the Customer to make reasonable and justifiable upgrades to its equipment to conform to the Company's equipment.

ARTICLE 4 Rates and Charges

4.1 The Customer shall pay a Monthly Demand Charge which shall be determined by multiplying its Load Ratio Share at each Point of Delivery by one-twelfth (1/12) of the (i) the Annual 13.8 kV Revenue Requirements for the Service Year or (ii) the Annual Primary Revenue Requirements for the Service Year, as applicable, and summing the results over all Points of Delivery.

4.2 The Customer shall also pay a Monthly Customer Charge for each Point of Delivery, in addition to the other charges assessed pursuant to this Agreement, for those costs attributable to the billing, meter reading, record keeping, (all from FERC Uniform System of Accounts Nos. 901-905), and an allocation of administrative and general expenses (FERC Uniform System of Accounts Nos. 920-935) associated with each of these costs, all of which are related to the Distribution Customer's Distribution Service, and allocated on the basis of the total number of customers served by the Company.

ARTICLE 5 Billing and Payment

5.1 Within a reasonable time after the first day of each month, the Company shall submit an invoice to the Distribution Customer for the charges for all services furnished under this Agreement during the preceding month. Payment pursuant to invoices issued for service hereunder shall be due within twenty (20) days of receipt. All payments hereunder shall be made in immediately available funds payable to the Company. Billings hereunder, except those related to the Monthly Customer Charge, shall be based on reasonable cost estimates made by the Company subject to an Annual True-Up when actual costs for the Service Year are known. Such Annual True-Up shall occur no later than six (6) months after the close of the Service Year to which the Annual True-Up relates.

5.2 Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Company.

5.3 If the Customer fails to respond to established emergency load shedding and Curtailment procedures described in Article 6 to relieve emergencies on the Distribution System, the Company may assess an additional charge to the Customer. Said additional charge will be equal to two times the Monthly Demand Charge, for the month in which such failure to respond occurred.

5.4 If any governmental authority requires the payment of any fee or assessment not specifically provided for in any of the charge or rate provisions under this Agreement or imposes a sales, gross revenue, or other form of tax (other than a tax calculated on net income) with respect to payments made for service provided under this Agreement, including any applicable interest charged on any deficiency assessment made by the taxing authority, together with any further tax on such payments, the obligation to make payment for any such fee, assessment, or tax shall be borne by the Customer. The Company will make a separate filing with the FERC for recovery of any such costs from the Customer in accordance with Part 35 of FERC's regulations to the extent any such fee, assessment, or tax is paid by the Company.

5.5 If the Company incurs tax liability currently for which it will in subsequent years receive tax benefits (for example, a taxable contribution in aid of construction), then the

Customer shall pay to the Company an amount sufficient to reimburse the Company, on a net present value basis, for the reasonably projected costs resulting from the tax liability incurred in the current year less the reasonably projected tax benefits received by the Company in future years. The discount rate to be applied in such calculation will be the rate of return value in effect and approved by the DTE at the time the liability was incurred.

5.6 If the Company takes a position that any particular transaction under any section of this Agreement does not constitute a taxable contribution in aid of construction, as described in Article 5.5, and that position is subsequently reversed by Treasury ruling or regulation or court action, then the Customer shall pay to the Company an amount calculated as described above, but additionally taking into account any interest and/or penalty assessment required to be paid by the Company.

5.7 In the event of a billing dispute between the Company and the Distribution Customer, the Company will continue to provide service under this Agreement as long as the Distribution Customer (i) pays the Company the entire undisputed amount that is due and itemizes the basis for its dispute in a notice to the Company within ninety (90) days after the date of the bill, (ii) continues to make all payments not in dispute, and (iii) pays to the Company or into an independent escrow account (established in accordance with a mutually agreed upon escrow agreement) the portion of the invoice in dispute, pending resolution of such dispute. If the Distribution Customer fails to meet these three requirements for continuation of service, then the Company may provide notice to the Distribution Customer of its intention to suspend service in sixty (60) days, in accordance with FERC policy. Upon final resolution of the dispute, in accordance with procedures set forth in Article 11 of this Agreement, if a refund is due to either Party, the Company or the Customer, as appropriate, shall make such refund, together with applicable accrued interest calculated in accordance with 18 CFR 35.19a(a)(2)(iii) through the date on which payment is made, within ten (10) business days of such resolution.

5.8 Within one (1) year following a calendar year, during normal business hours, each Party shall have the right to audit the other's accounts and records pertaining to transactions under this Agreement that occurred during such calendar year at the offices where such accounts and records are maintained; provided that at least five (5) days' notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that reasonably relate to the services provided by the Company under this Agreement for said calendar year. The Party to be audited shall be entitled to review the audit report and any supporting materials. The Party to be audited shall have the right to charge the other Party for its reasonable costs of assisting in any such audit.

ARTICLE 6 **Load Shedding and Curtailments**

6.1 During any period when the Company, or its Designated Agent, determines that a distribution constraint exists on the Distribution System, and such constraint, in the exercise of the Company's reasonable judgment, may impair the reliability of the Transmission System or Distribution System, the Company, or its Designated Agent, will take whatever actions, consistent with Prudent Utility Practice and with Section 3.1, that are reasonably necessary to maintain the reliability of the Transmission System or Distribution System.

6.2 In the event the Company or its Designated Agent determines in good faith and in accordance with Prudent Utility Practice that a distribution constraint on the Company's Distribution System cannot be relieved and the Company or its Designated Agent further determines in good faith and in accordance with Prudent Utility Practice that it is necessary to Curtail the Company's Distribution System, or a portion thereof, in order to maintain reliable operation of the Transmission System or Distribution System, Curtailments shall be made on a non-discriminatory basis to the transactions that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Prudent Utility Practice and Section 3.1, the Company will curtail service to the Customer and any other Distribution Service customers on a basis comparable to the curtailment of service to the Company's Native Load Customers.

6.3 When the Company determines in accordance with Prudent Utility Practice that a System Emergency exists on the Distribution System and implements emergency procedures to curtail Distribution Service, the Customer shall, without liability to the Company, make the required reductions upon the reasonable request of the Company.

6.4 The Company reserves the right to curtail, in whole or in part, any Distribution Service when, in the Company's reasonable discretion exercised in good faith and in accordance with Prudent Utility Practice and consistent with Section 3.1, an adverse condition or disturbance or other unforeseen condition impairs or degrades the reliability and/or service quality of its Distribution System and in cases where the continuance of Distribution Service would endanger persons or property. The Company may also, without liability on the Company's part, curtail service for the purpose of (i) making necessary adjustments to, changes in, or repairs on its lines, substations and facilities; (ii) limiting the extent of or damage caused by any adverse conditions or disturbance; (iii) preventing damage to generation or transmission facilities; or (iv) expediting restoration of service. The Company will notify the Customer in a timely manner as early as practicable in advance of any scheduled Curtailments.

6.5 Customer shall comply with all applicable current and future NERC, NPCC and ISO planning and operating criteria which describe the requirements for load shedding schemes.

ARTICLE 7 **<u>Operation and Maintenance of the Facilities</u>**

7.1 Unless otherwise specified, the Customer is expected to maintain a power factor of not less than 80% lagging at each Point of Delivery. If such requirement is not met, the Company may require the Customer to furnish, install and maintain at no cost to the Company, such corrective equipment as the Company may deem necessary under the circumstances. Alternatively, Company may elect to install such corrective equipment at the Customer's reasonable expense.

7.2 The Customer shall not energize a de-energized Company circuit and shall provide equipment to prevent this from occurring.

7.3 If the Company determines that (i) any of the Customer's equipment fails to perform in a manner consistent with Prudent Utility Practice and in accordance with this Agreement,or (ii) the Customer has failed to perform proper testing or maintenance of its equipment in accordance with Prudent Utility Practice and the terms of this Agreement, the Company shall give the Customer notice to take corrective action. The Company shall provide such notice as soon as practicable upon such determination. If the Customer fails to initiate corrective action promptly, but in any event not later than three (3) days from the date of the notification, and if in the Company's reasonable judgment, consistent with Prudent Utility Practice, leaving the Customer's facilities interconnected with the Company's Distribution System would create a System Emergency, the Company may, with as much prior verbal notification to the Customer as practicable, open the relevant interconnections between the Customer and the Company until appropriate corrective actions have been completed by the Customer and verified by the Company. In the case of such interruption, the Company shall immediately confer with the Customer regarding the conditions causing such interruption and its recommendation concerning timely correction thereof. Both Parties shall act promptly to correct the condition leading to the interruption and to restore the interconnection.

7.4 The Customer, at the Company's request, shall operate its system during a System Emergency in a manner to mitigate the System Emergency. Such operation may call for full or partial interruption of power either by manual or automatic means. In the event of a System Emergency, absent any Company request, the Customer shall make no changes to its operations in response to the System Emergency, other than changes imposed by the action of automatic control devices on the Company's and/or the Customer's system.

ARTICLE 8 Metering

8.1 The Company or its designee shall, in accordance with Prudent Utility Practice and at the Customer's expense, own, operate, test, and maintain all metering related equipment (including apparatus that controls the temperature and environment for protecting such equipment) associated with the Points of Delivery which measures electricity flows between the Company and the Customer. The information provided by the metering facilities shall meet the reasonable needs and approvals of both Parties, consistent with Prudent Utility Practice. The Company shall, at Customer's sole expense, install and maintain one communication line necessary for the data communications associated with these meters. The Customer shall also be responsible for associated communications fees assessed by third parties.

8.2 The Customer shall provide suitable space at mutually agreeable locations on its side of the Points of Delivery for installation of the metering and associated equipment at no cost to the Company. An appropriate loss compensation method based upon Prudent Utility Practice will be employed by the Parties for losses between the physical location of the meters and the Points of Delivery, to the extent those locations are not the same.

8.3 The Customer shall provide reasonable access, in accordance with Article 9 herein, including without limitation to Qualified Personnel of the Company for the purposes of installing, reading, inspecting, maintaining, testing, adjusting, removing, and replacing metering and data communications equipment. The Company shall notify the Customer within a reasonable period of time prior to exercising such access, except in cases of a System Emergency, for which the Company shall provide notification as soon as practicable following such access.

8.4 Unless otherwise agreed, all meters shall be sealed, and the seals shall be broken only by Qualified Personnel of the Company upon occasions when the meters are to be inspected, tested, adjusted, or recalibrated in accordance with Prudent Utility Practice upon prior notification to and in the presence of duly authorized Qualified Personnel of the Customer (unless the Customer fails to make any Qualified Personnel available in a timely fashion at a time mutually agreed upon in good faith by the Parties).

8.5 All metering equipment installed pursuant to this Article may be routinely tested in accordance with Prudent Utility Practice by the Company at the Company's expense, but not more often than annually, in accordance with ISO Operating Procedure 18 or any successor requirement of NEPOOL or the ISO, as appropriate. The Company shall notify the Customer prior to conducting any metering tests, and the Customer may observe the test. If the meter or meter related equipment is found to be inaccurate by a margin greater than that allowed under ISO Operating Procedure 18 or any successor requirement of NEPOOL or the ISO, as appropriate, or is otherwise defective, it shall be repaired, adjusted, or replaced at the Customer's expense. The determination of percent accuracy shall be in accordance with the weighted average percent registration as described in ANSI C12.1-1988, Section 6.1.8.1.

8.6 Except to the extent required in Section 8.7 below and in addition to the Company's routine testing, either Party may request that the metering equipment be tested, and the Company shall carry out the test at the expense of the requesting Party.

8.7 If either Party believes that there has been a meter failure or stoppage, it shall immediately notify the other and require immediate testing at the Customer's sole expense. If, at any time, any metering equipment is found to be inaccurate by a margin greater than that allowed under ISO Operating Procedure 18, the Company shall cause such metering equipment to be made accurate or replaced at the Customer's sole expense, except to the extent such inaccuracies are caused by the negligence or willful act or omission of the Company. Meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained. If the period of inaccuracy cannot be determined, the Parties agree to adjust the meter readings for a period equal to half the time between the last known valid reading and the date of the test which confirmed the inaccuracy and for all time between such test date and the date the metering was made accurate.

8.8 The Company shall maintain and make available for review by the Customer in a timely manner records of all meter tests conducted pursuant to this Article, for a period of one (1) year following the completion of such tests.

8.9 For ISO load reporting purposes and consistent with ISO rules, the Company shall be the assigned meter reader. However, the Customer's Designated Agent shall forward month-end meter readings to Company. Upon the execution of this Agreement, the Customer shall notify the Company of its Designated Agent. Customer's responsibilities to supply the Company with physical and electronic access to meters and recorders and to supply the Company with month-end meter readings pursuant to this Article shall continue until such time as the Company no longer requires these services for its load calculation processes.

ARTICLE 9 <u>Access to Facilities</u>

To the extent not inconsistent with any preexisting agreement, the Customer hereby agrees to grant and shall provide, without charge to the Company for the term of this Agreement, such access as may be reasonably necessary for reasonable ingress and egress over property owned and/or leased by the Customer to the Company's equipment so that the Company can meet its obligations under this Agreement. Such access by the Company for these limited purposes shall in all cases be subject to Customer rules, regulations and procedures governing access to Customer property. If the Company is constructively denied access under this Agreement, then to the extent that such denial causes the Company to be unable to meet its obligations under this Agreement, the Company shall be excused from performance to that limited extent.

ARTICLE 10 <u>Applicable Regulations and Interpretation</u>

10.1 The Company's obligation to provide Distribution Service pursuant to this Agreement and to complete any construction hereunder which may be necessary for the provision of Distribution Service, if any, is subject to the condition that all requisite governmental and regulatory approvals for the provision of such service and construction are obtained. The

Company's obligation is also conditioned on receipt of appropriate votes and approvals which may be required under the ISO Tariff. Each Party shall exercise due diligence and shall cooperate with the other to secure all appropriate approvals, including those of NEPOOL or ISO.

10.2 This Agreement is made subject to present and future state and federal laws and to present and future regulations and orders properly issued by state or federal bodies having jurisdiction. This Agreement shall be interpreted pursuant to the laws of the Commonwealth of Massachusetts, the Federal Power Act, and any regulatory agency having jurisdiction over the particular matter.

ARTICLE 11 Dispute Resolution

11.1 The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations between the affected Parties. Each Party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. They shall engage in such good-faith negotiations for a period of not less than 30 calendar days, unless: (a) a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute by FERC or a court or agency with jurisdiction over the dispute; or (b) the provisions of this Agreement otherwise provide a Party the right to submit a dispute directly to FERC for resolution. Any dispute that is not resolved through good-faith negotiations may be submitted by either Party for resolution by FERC or a court or agency with jurisdiction over the dispute upon the conclusion of such negotiations. Either Party may request that any dispute submitted to FERC for resolution be subject to FERC settlement procedures. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of all affected Parties to participate in such an alternative dispute resolution process. In any event, physical accidents or events giving rise to negligence or intentional tort claims for the recovery of property damages and/or damages for personal injury, or other disputes where the amount in controversy exceeds One Million Dollars ($1,000,000) shall not be considered arbitrable claims or subject to any other form of alternate dispute resolution.

11.2 Nothing in this Agreement shall restrict the rights of either party to file a complaint with the FERC under relevant provisions of the Federal Power Act.

ARTICLE 12 <u>Force Majeure</u>

Neither the Company nor the Customer will be considered in default as to any obligation under this Agreement, and shall be excused from performance or liability for damage to the other Party if and to the extent prevented from fulfilling the obligation due to an event of Force Majeure; provided that no event of Force Majeure shall excuse an entity of the obligation to pay amounts due under this Agreement. However, a Party whose performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement and remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party. Any Party claiming Force Majeure shall promptly notify the other Party of the commencement and end of each event of Force Majeure.

ARTICLE 13 <u>Limitation of Liability</u>

13.1 Except to the extent of the Company's negligence or willful misconduct, the Customer shall be responsible for all physical damage to or destruction of the property, equipment and/or facilities owned by it and/or its affiliates, regardless of who brings the claim and regardless of who caused the damage and shall not seek recovery or reimbursement from the Company, its officers, directors, employees, agents, successors or assigns or its affiliates or any of their respective officers, directors, employees, agents, successors or assigns for such damage; but in any such case the Company will exercise reasonable diligence to remove the cause of any disability at the earliest practicable time. Each party shall be solely liable for all claims of its own employees arising under any worker's compensation laws.

13.2 To the fullest extent permitted by law and notwithstanding other provisions of this Agreement, in no event shall either Party or their officers, directors, employees, agents, successors or assigns or their affiliates or any of their respective officers, directors, employees, agents, successors or assigns be liable to the other Party, whether in contract, warranty, tort, negligence, strict liability, or otherwise, for special, indirect, incidental, consequential (including, without limitation, replacement power costs, lost profits or revenues, and lost business opportunities), or punitive damages, attorneys fees or costs arising out of, or connected in any way with performance or nonperformance of this Agreement or any activity associated with or arising out of this Agreement.

13.3 The provisions of this Article and Article 14 shall survive termination, cancellation, suspension, completion or expiration of this Agreement.

ARTICLE 14 Indemnification

To the extent not prohibited by law, each Party (the “Indemnifying Party”) agrees to defend, indemnify and hold harmless the other Party (the “Indemnified Party”) and its employees, officers, members, directors and agents from and against any and all claims, costs (including all attorney fees and all costs of litigation and investigation), demands, actions, including actions for personal injury or wrongful death, actions for property damage, and any other types of claims asserted by third persons alleging a violation of law or for any other cause, arising from or related to the Indemnifying Party’s negligent acts, omissions or willful misconduct, and without limiting the foregoing, any negligence or willful misconduct of the Indemnifying Party’s members, officers, employees, agents, volunteers, invitees and guests; provided, however, that this obligation to defend, indemnify and hold harmless shall not apply to claims which the Indemnifying Party demonstrates were caused by the negligence or willful misconduct of the Indemnified Party.

In case any action or proceeding is brought against the Indemnifying Party or any such employee, officer, member, director and agent by reason of any claim which may be subject to either party’s indemnification obligations contained in this Article 14, the Indemnifying Party, upon notice from the affected party, shall resist or defend such action or proceeding with counsel acceptable to the Indemnified Party. Subject to the foregoing, the Indemnified Party shall cooperate and join with the Indemnifying Party at the expense of Indemnifying Party as may be required in connection with any action taken or defended by Indemnifying Party.

The Indemnified Party shall give the Indemnifying Party prompt written notice of any claims threatened or made or any suit instituted against it which could result in a claim of indemnification hereunder.

ARTICLE 15 Corporate Act and Obligation

This Agreement is the corporate act and obligation of the Customer and the Company and shall be binding upon and shall inure to the benefit of the Parties hereto and their successors and assigns. Any claim hereunder against any stockholder, director, officer, or member of the board of directors or trustees of either Party, in such capacity, is expressly waived.

ARTICLE 16 **Remedies**

16.1 In the event that the Customer fails to make full payment of an undisputed bill rendered under this Agreement on or before the due date, the Company will notify the Customer in writing of such delinquency, and the Customer will have thirty (30) days from the date of such notice to cure such delinquency. In the event that the Customer fails to make full payment of the delinquent amount (including interest accrued in accordance with 18 CFR § 35.19a(a)(2)(iii) within such thirty (30) day period, the Customer will be in default. In the event of a default, the Company shall have the right to terminate service under this Agreement upon a filing with FERC.

16.2 If the Customer fails, in a material respect, to fulfill any of its obligations under this Agreement other than its payment obligation, and such failure shall have continued for and not been remedied within sixty (60) days after receipt of a notice from the Company specifying the nature of such failure in reasonable detail, the Customer shall be deemed in default, and the Company shall have the right to suspend service and, upon a filing with FERC, terminate service under this Agreement, and, in such event, the Customer reserves the right to object to such termination.

16.3 If the Company fails, in a material respect, to fulfill any of its obligations under this Agreement and such failure shall have continued for and not been remedied within sixty (60) days after receipt of a notice from the Customer specifying the nature of such failure in reasonable detail, the Company shall be deemed in default, the Customer shall have the right to make all payments into an independent escrow account in accordance with Section 5.7 herein, and the Customer shall have the right to file a complaint with the FERC under relevant provisions of the Federal Power Act, in accordance with Section 11.2 herein. If the FERC, in a final order and after the expiration of all associated appeals, agrees with the Customer that the Company has failed in a material respect to fulfill the disputed obligations under the Agreement, then the Customer shall be entitled to a refund of the amounts paid into the escrow account associated with the disputed issue and shall thereafter pay the remaining balance of the escrow account to the Company. If the FERC, in a final order and after the expiration of all associated appeals, does not agree with the Customer that the Company has failed in a material respect to fulfill the disputed obligations under the Agreement, then the Company shall be entitled to full payment of the amounts paid into the escrow account.

16.4 The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which the Company or the Customer are legally entitled.

ARTICLE 17 **<u>Assignment</u>**

This Agreement shall inure to the benefit of and bind the respective successors and assigns and successors in title of the Parties hereto. No assignment by either Party of its rights and obligations hereunder shall be made or become effective without the prior written consent of the other Party in each case being obtained, which consent shall not be unreasonably withheld or delayed, except that this Agreement may be assigned without such consent to an entity controlling, controlled by or under common control with the assigning Party, or to a person acquiring all or a controlling interest in the business assets of such Party. No assignment or transfer of rights shall relieve the assigning Party from full liability and financial responsibility for performance unless both the assignee or transferee and the other Party have so consented in writing, said consent not to be unreasonably withheld.

ARTICLE 18 **<u>Subcontractors</u>**

18.1 Nothing in this Agreement shall prevent the Parties from utilizing the services of subcontractors as they deem appropriate; provided, however, the Parties agree that, where applicable, all said subcontractors shall comply with the terms and conditions of this Agreement.

18.2 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. Each Party shall be fully responsible to the other Party for the acts and/or omissions of any subcontractor it hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon the Parties, shall be equally binding upon and shall be construed as having application to any subcontractor.

18.3 The obligations under this Article shall not be limited in any way by any limitation in subcontractor's insurance.

ARTICLE 19 **<u>Substitute ISO/NEPOOL Rules and Procedures</u>**

In the event that any or all of the ISO/NEPOOL rules and procedures referred to herein shall cease to be established without successor rules and procedures having been established, or if the Company ceases participation in NEPOOL or ISO, the Company may impose reasonable substitute rules and procedures that do not materially alter the obligations of the Customer as such obligations existed under the ISO and/or NEPOOL rules and procedures, and such substitute rules and procedures shall thereafter be a part of this Agreement for all purposes.

ARTICLE 20 Regional Network Service

In the event the Customer does not receive regional network service directly from the ISO pursuant to the ISO Tariff, any invoices received by the Company from the ISO to provide such service to the Customer will be charged to the Customer in accordance with the terms of this Agreement.

ARTICLE 21 Miscellaneous

21.1 **Changes in Law.** If FERC, any state or state regulatory commission, ISO or NEPOOL implements a change in any law, regulation, rule or practice, the Parties shall negotiate in good faith to determine the amendments, if any, to this Agreement that may be necessary to conform the terms of this Agreement to such change, and the Company shall file such amendments with FERC.

21.2 **Notices**. Any notice, request, demand or statement required to be given by either Party to the other in connection with this Agreement shall be given in writing and shall be sent by registered or certified mail, return receipt requested, postage prepaid, or by hand delivery, or by overnight delivery, with acknowledged receipt of delivery. Notice shall be deemed given at the date of acceptance or refusal of acceptance shown on such receipt.

Any such notice to the Company shall be to the following address:

NSTAR Electric & Gas Corporation
One NSTAR Way, NE240
Westwood, MA 02090
Attention: Director of Transmission Business Strategy

with a copy to:

NSTAR Electric & Gas Corporation
800 Boylston Street, P1700
Boston, MA 02199-8003
Attention: Legal Department

Any such notice to the Customer shall be to the following address:

Massachusetts Port Authority
One Harborside Drive, Suite 200S
East Boston, MA 02128
Attention: Utility Manager

with a copy to:

Massachusetts Port Authority
One Harborside Drive, Suite 200S
East Boston, MA 02128
Attention: Chief Legal Counsel

Any payments required to be made by the Customer under this Agreement shall be mailed to the Company at the following address:

NSTAR Electric & Gas Corporation
One NSTAR Way
Westwood, MA 02090
Attention: Accounts Receivable

Any notice, request or demand pertaining to matters of an operating nature, which matters do not include requests for additional Distribution Service or modified Distribution Service under this Agreement, may be served in person or by United States mail, messenger, telephone, telegraph, facsimile transmission or orally, as circumstances dictate, to the person designated in writing by the Party as its representative for such purposes; provided that should the same not be written, confirmation thereof shall be made in writing as soon as reasonably practicable thereafter, upon request of the Party being served. Any payment required to be made hereunder may be made via wire transfer or other electronic method agreeable to the Parties using wiring instructions to be provided by the other Party.

21.3 **Headings.** The descriptive headings of the various sections of this Agreement have been inserted for convenience of reference only and shall in no way define, modify or restrict any of the terms and provisions thereof.

21.4 **Further Assurances.** From time to time after the execution of this Agreement, each Party shall execute such instruments, upon the reasonable request of the other, as may be necessary or appropriate, to implement this Agreement.

21.5 **Amendments.** In the event that it is deemed necessary to amend this Agreement, the Parties will attempt to agree upon such amendment and the Company will submit such mutually agreed upon amendment(s) to the FERC for filing and acceptance. However, the Company shall have the right at any time to amend the provisions of this Agreement relating to the method of calculating the amount charged by the Company to the Customer to provide Distribution Service under this Agreement by filing an amendment with the FERC and serving such amendment on the Customer. Such an amendment shall become effective as a change of rate under Section 205 of the Federal Power Act. An amendment effecting the above-referenced provisions of this Agreement unilaterally submitted by the Customer to the FERC shall be in accordance with Section 206 of the Federal Power Act.

21.7 **Third-Party Beneficiaries.** This Agreement is not intended to and shall not create rights of any character whatsoever in favor of any person, corporation, association, or entity other than the Parties to this Agreement, and obligations herein assumed are solely for the use and benefit of the Parties to this Agreement.

21.8 **No Dedication.** Any undertaking by one Party to the other under any provisions of the Agreement shall not constitute the dedication of the electric system, or any portion thereof, of any Party to the public or to the other Party, and it is understood and agreed that any such undertaking by any Party shall cease upon termination of the Agreement.

21.9 **Other Agreements.** Nothing contained in this Agreement shall restrict or limit either Party from establishing, altering or terminating interconnection points with any entity not a Party to this Agreement or amending or entering into such agreements.

21.10 **Several Obligations.** Notwithstanding any provisions of the Agreement to the contrary, the Parties do not intend to create hereby a joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit, and any construction of the Agreement to the contrary shall render this Agreement null and void from its inception. Except where specifically stated in this Agreement to be otherwise, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective. Each Party shall be individually and severally liable for its own obligations under this Agreement.

21.11 **Waivers.** Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter. Failure to enforce rights of a Party under this Agreement shall not be deemed a waiver of such rights for any reason.

21.12 **Entire Agreement.** This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof, and supersedes any other prior understanding or agreement between the Parties with respect thereto.

21.13 **Interpretation.** For the purpose of interpreting this Agreement, to the extent that there exists any conflict between the provisions of this Agreement and the provisions of the Service Agreement and the Interconnection Agreement, if any, the provisions of this Agreement shall prevail.

21.14 **No Presumption.** Each Party has been advised by, its own legal counsel and, in executing this Agreement, does not rely upon any representations, promises, or inducements made by any other Party or its representatives, with the sole exception of the premises and provisions set forth herein. The fact that a Party or counsel for a party drafted a provision or provisions of this Agreement shall not cause that provision or those provisions to be construed against the drafting Party.

21.15 **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be deemed an original.

21.16 **Ratification.** This Agreement shall not be binding on either Party until ratified by the Customer's Board of Members, which shall occur no later than 30 days from the date hereof.

IN WITNESS WHEREOF, the Company and the Customer have caused this instrument to be executed by their duly authorized representatives as of the day and year first above written.

NSTAR ELECTRIC COMPANY

By: ______________________________
Name:
Title:

MASSACHUSETTS PORT AUTHORITY

By: ______________________________
Name:
Title:

ATTACHMENT A

NSTAR ELECTRIC COMPANY

ANNUAL 13.8KV DISTRIBUTION REVENUE REQUIREMENTS

I. DEFINITIONS

Capitalized terms have the following definitions:

A. ALLOCATION FACTORS

1. Distribution Wages and Salaries Allocation Factor shall equal the ratio of Distribution-related direct wages and salaries including those of affiliated Companies to NSTAR Electric's total direct wages and salaries including those of the affiliated companies and excluding administrative and general wages and salaries.

2. 13.8kv Distribution Plant Allocation Factor shall equal the ratio of 13.8kv Distribution Plant to Total Investment in Distribution Plant.

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Distribution Plant and Distribution Related General Plant to Total Plant in Service.

B. TERMS

Administrative and General Expense shall equal NSTAR Electric's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Loss on Reacquired Debt shall equal NSTAR Electric's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal NSTAR Electric's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Distribution Plant shall equal NSTAR Electric's Distribution expenses as recorded in FERC Account No. 403.

General Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal NSTAR Electric's general expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of NSTAR Electric's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in NSTAR Electric's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of NSTAR Electric's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in NSTAR Electric's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in NSTAR Electric's FERC Account Nos. 408.1.

Plant Held for Future Use shall equal NSTAR Electric's balance in FERC Account No. 105.

Prepayments shall equal NSTAR Electric's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal NSTAR Electric's expenses as recorded in FERC Account No. 924.

13.8kv Distribution Plant Investment shall equal NSTAR Electric's

13.8kv Distribution plant as recorded in FERC Account Nos. 360 –373, which is operated at the 13.8kv level.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190, for those balances that are directly related to distribution, excluding those directly related to transmission or other businesses.

Total Loss on Reacquired Debt shall equal NSTAR Electric's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal NSTAR Electric's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal NSTAR Electric's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Distribution Depreciation Reserve shall equal NSTAR Electric's Distribution reserve balance as recorded in FERC Account 108.

Distribution Operation and Maintenance Expense shall equal NSTAR Electric's expenses as recorded in FERC Account Nos. 580 - 598.

Distribution Plant shall equal NSTAR Electric's Gross Plant balance as recorded in FERC Account Nos. 360-373.

Distribution Plant Materials and Supplies shall equal NSTAR Electric's balance as assigned to Distribution, as recorded in FERC Account No. 154.

II. CALCULATION OF DISTRIBUTION REVENUE REQUIREMENTS

The Distribution Revenue Requirement shall equal the sum of NSTAR Electric's (A) Return and Associated Income Taxes, (B) Distribution Depreciation Expense, (C) Distribution Related Amortization of Loss on Reacquired Debt, (D) Distribution Related Amortization of Investment Tax Credits, (E) Distribution Related Municipal Tax

Expense, (F) Distribution Related Payroll Tax Expense, (G) Distribution Operation and Maintenance Expense, (H) Distribution Related Administrative and General Expenses, minus (I) Distribution Rents Received from Electric Property.

A. Return and Associated Income Taxes shall equal the product of the Distribution Investment Base and the Cost of Capital Rate.

1. Distribution Investment Base

The Distribution Investment Base will be the year end balances of (a) 13.8kv Distribution Plant, plus (b) Distribution Related General Plant, plus (c) Distribution Plant Held for Future Use, less (d) Distribution Related Depreciation Reserve, less (e) Distribution Related Accumulated Deferred Taxes, plus (f) Distribution Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Distribution Prepayments, plus (i) Distribution Materials and Supplies, plus (j) Distribution Related Cash Working Capital.

(a) 13.8kv Distribution Plant will equal the balance of NSTAR Electric's 13.8kv Investment in Distribution Plant.

(b) Distribution Related General Plant shall equal NSTAR Electric's balance of investment in General Plant multiplied by the Distribution Wages and Salaries Allocation Factor and the 13.8KV Distribution Plant Allocation Factor.

(c) Distribution Plant Held for Future Use shall equal the balance of Distribution-related Plant Held for Future Use multiplied by the 13.8KV Distribution Plant Allocation Factor.

(d) Distribution Related Depreciation Reserve shall equal the balance of Total Distribution Depreciation Reserve, plus the balance of Distribution Related General Plant Depreciation Reserve. Distribution Related General Plant Depreciation Reserve shall equal the product General Plant Depreciation Reserve and the Distribution Wages and Salaries Allocation Factor. This sum shall be multiplied by the 13.8KV Distribution Plant Allocation Factor.

(e) Distribution Related Accumulated Deferred Taxes shall equal NSTAR Electric's electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to distribution, plus the balances not directly related to other businesses), multiplied by the Plant Allocation Factor, further multiplied by the 13.8KV Distribution Plant Allocation Factor.

(f) Distribution Related Loss on Reacquired Debt shall equal NSTAR Electric's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the 13.8KV Distribution Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal NSTAR Electric's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Distribution Wages and Salaries Allocation Factor, plus NSTAR Electric's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the 13.8KV Distribution Plant Allocation Factor.

(h) Distribution Prepayments shall equal NSTAR Electric's electric balance of prepayments multiplied by the Distribution Wages and Salaries Allocation Factor and further multiplied by the 13.8KV Distribution Plant Allocation Factor.

(i) Distribution Materials and Supplies shall equal NSTAR Electric's electric balance of Distribution Plant Materials and Supplies, multiplied by the 13.8KV Distribution Plant Allocation Factor.

(j) Distribution Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Distribution Operation and Maintenance Expense and the Distribution Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) NSTAR Electric's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NSTAR Electric's long-term debt then outstanding and the ratio that long-term debt is to NSTAR Electric's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NSTAR Electric's preferred stock then outstanding and the ratio that preferred stock is to NSTAR Electric's total capital.

(iii) the return on equity component, which shall be the product of the allowed return on equity ("ROE") of the common equity and the ratio that common equity is to NSTAR Electric's total capital. The allowed ROE shall be the ROE established pursuant to the provisions of the Federal Power Act for NSTAR Electric.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Distribution Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Distribution Depreciation Expense , as defined in Section II.B., and D is Distribution Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Distribution Depreciation Expense, as defined in Section II.B., D is the Distribution Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Distribution Depreciation Expense shall equal the 13.8KV Distribution Plant Allocation Factor, multiplied by the sum of Depreciation Expense for Distribution Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Distribution Wages and Salaries Allocation Factor.

C. Distribution Related Amortization of Loss on Reacquired Debt shall equal NSTAR Electric's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the 13.8KV Distribution Plant Allocation Factor.

D. Distribution Related Amortization of Investment Tax Credits shall equal NSTAR Electric's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the 13.8KV Distribution Plant Allocation Factor.

E. Distribution Related Municipal Tax Expense shall equal NSTAR Electric's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the 13.8KV Distribution Plant Allocation Factor.

F. Distribution Related Payroll Tax Expense shall equal NSTAR Electric's total electric payroll tax expense, multiplied by the Distribution Wages and Salaries Allocation Factor, further multiplied by the 13.8KV Distribution Plant Allocation

Factor.

G. Distribution Operation and Maintenance Expense shall equal Distribution Operation and Maintenance Expenses multiplied by the 13.8KV Distribution Plant Allocation Factor.

H. Distribution Related Administrative and General Expenses shall equal the sum of (1) Distribution Provider's Administrative and General Expenses multiplied by the Distribution Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Distribution Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State Distribution related expenses or assessments, plus specific Distribution related expenses included in Account 930.1. This sum shall be multiplied by the 13.8KV Distribution Plant Allocation Factor.

I. Distribution Rents Received from Electric Property shall equal any Account 454 Rents from electric property associated with Distribution Plant multiplied by the 13.8KV Distribution Plant Allocation Factor.

ATTACHMENT B

NSTAR ELECTRIC COMPANY

ANNUAL PRIMARY DISTRIBUTION REVENUE REQUIREMENTS

I. DEFINITIONS

Capitalized terms have the following definitions:

A. ALLOCATION FACTORS

1. Distribution Wages and Salaries Allocation Factor shall equal the ratio of Distribution-related direct wages and salaries including those of affiliated Companies to NSTAR Electric's total direct wages and salaries including those of the affiliated companies and excluding administrative and general wages and salaries.

2. Primary Distribution Plant Allocation Factor shall equal the ratio of Primary Distribution Plant to Total Investment in Distribution Plant.

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Distribution Plant and Distribution Related General Plant to Total Plant in Service.

B. TERMS

Administrative and General Expense shall equal NSTAR Electric's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1.

Amortization of Loss on Reacquired Debt shall equal NSTAR Electric's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal NSTAR Electric's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Distribution Plant shall equal NSTAR Electric's Distribution expenses as recorded in FERC Account No. 403.

General Plant shall equal NSTAR Electric's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal NSTAR Electric's general expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal NSTAR Electric's general reserve balance as recorded in FERC Account No. 108.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of NSTAR Electric's FAS106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in NSTAR Electric's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of NSTAR Electric's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in NSTAR Electric's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in NSTAR Electric's FERC Account Nos. 408.1.

Plant Held for Future Use shall equal NSTAR Electric's balance in FERC Account No. 105.

Prepayments shall equal NSTAR Electric's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal NSTAR Electric's expenses as recorded in FERC Account No. 924.

Primary Distribution Plant Investment shall equal NSTAR Electric's

Primary Distribution plant as recorded in FERC Account Nos. 360 –373, which is operated at the Primary level.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190, for those balances that are directly related to distribution, excluding those directly related to transmission or other businesses.

Total Loss on Reacquired Debt shall equal NSTAR Electric's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal NSTAR Electric's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal NSTAR Electric's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Distribution Depreciation Reserve shall equal NSTAR Electric's Distribution reserve balance as recorded in FERC Account 108.

Distribution Operation and Maintenance Expense shall equal NSTAR Electric's expenses as recorded in FERC Account Nos. 580 - 598.

Distribution Plant shall equal NSTAR Electric's Gross Plant balance as recorded in FERC Account Nos. 360-373.

Distribution Plant Materials and Supplies shall equal NSTAR Electric's balance as assigned to Distribution, as recorded in FERC Account No. 154.

II. CALCULATION OF DISTRIBUTION REVENUE REQUIREMENTS

The Distribution Revenue Requirement shall equal the sum of NSTAR Electric's (A) Return and Associated Income Taxes, (B) Distribution Depreciation Expense, (C) Distribution Related Amortization of Loss on Reacquired Debt, (D) Distribution Related Amortization of Investment Tax Credits, (E) Distribution Related Municipal Tax

Expense, (F) Distribution Related Payroll Tax Expense, (G) Distribution Operation and Maintenance Expense, (H) Distribution Related Administrative and General Expenses, minus (I) Distribution Rents Received from Electric Property.

A. Return and Associated Income Taxes shall equal the product of the Distribution Investment Base and the Cost of Capital Rate.

1. Distribution Investment Base

The Distribution Investment Base will be the year end balances of (a) Primary Distribution Plant, plus (b) Distribution Related General Plant, plus (c) Distribution Plant Held for Future Use, less (d) Distribution Related Depreciation Reserve, less (e) Distribution Related Accumulated Deferred Taxes, plus (f) Distribution Related Loss on Reacquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Distribution Prepayments, plus (i) Distribution Materials and Supplies, plus (j) Distribution Related Cash Working Capital.

(a) Primary Distribution Plant will equal the balance of NSTAR Electric's Primary Investment in Distribution Plant.

(b) Distribution Related General Plant shall equal NSTAR Electric's balance of investment in General Plant multiplied by the Distribution Wages and Salaries Allocation Factor and the Primary Distribution Plant Allocation Factor.

(c) Distribution Plant Held for Future Use shall equal the balance of Distribution-related Plant Held for Future Use multiplied by the Primary Distribution Plant Allocation Factor.

(d) Distribution Related Depreciation Reserve shall equal the balance of Total Distribution Depreciation Reserve, plus the balance of Distribution Related General Plant Depreciation Reserve. Distribution Related General Plant Depreciation Reserve shall equal the product General Plant Depreciation Reserve and the Distribution Wages and Salaries Allocation Factor. This sum shall be multiplied by the Primary Distribution Plant Allocation Factor.

(e) Distribution Related Accumulated Deferred Taxes shall equal NSTAR Electric's electric balance of Total Accumulated Deferred Income Taxes (for those balances that are directly related to distribution, plus the balances not directly related to other businesses), multiplied by the Plant Allocation Factor, further multiplied by the Primary Distribution Plant Allocation Factor.

(f) Distribution Related Loss on Reacquired Debt shall equal NSTAR Electric's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the Primary Distribution Plant Allocation Factor.

(g) Other Regulatory Assets/Liabilities shall equal NSTAR Electric's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Distribution Wages and Salaries Allocation Factor, plus NSTAR Electric's electric balance of FAS 109 multiplied by the Plant Allocation Factor. This sum shall be multiplied by the Primary Distribution Plant Allocation Factor.

(h) Distribution Prepayments shall equal NSTAR Electric's electric balance of prepayments multiplied by the Distribution Wages and Salaries Allocation Factor and further multiplied by the Primary Distribution Plant Allocation Factor.

(i) Distribution Materials and Supplies shall equal NSTAR Electric's electric balance of Distribution Plant Materials and Supplies, multiplied by the Primary Distribution Plant Allocation Factor.

(j) Distribution Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Distribution Operation and Maintenance Expense and the Distribution Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) NSTAR Electric's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of NSTAR Electric's long-term debt then outstanding and the ratio that long-term debt is to NSTAR Electric's total capital.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NSTAR Electric's preferred stock then outstanding and the ratio that preferred stock is to NSTAR Electric's total capital.

(iii) the return on equity component, which shall be the product of the allowed return on equity ("ROE") of the common equity and the ratio that common equity is to NSTAR Electric's total capital. The allowed ROE shall be the ROE established pursuant to the provisions of the Federal Power Act for NSTAR Electric.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1 - FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Distribution Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Distribution Depreciation Expense , as defined in Section II.B., and D is Distribution Investment Base, as determined in II.A.1., above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Distribution Depreciation Expense, as defined in Section II.B., D is the Distribution Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

B. Distribution Depreciation Expense shall equal the Primary Distribution Plant Allocation Factor, multiplied by the sum of Depreciation Expense for Distribution Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Distribution Wages and Salaries Allocation Factor.

C. Distribution Related Amortization of Loss on Reacquired Debt shall equal NSTAR Electric's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the Primary Distribution Plant Allocation Factor.

D. Distribution Related Amortization of Investment Tax Credits shall equal NSTAR Electric's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the Primary Distribution Plant Allocation Factor.

E. Distribution Related Municipal Tax Expense shall equal NSTAR Electric's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the Primary Distribution Plant Allocation Factor.

F. Distribution Related Payroll Tax Expense shall equal NSTAR Electric's total electric payroll tax expense, multiplied by the Distribution Wages and Salaries Allocation Factor, further multiplied by the Primary Distribution Plant Allocation

Factor.

G. Distribution Operation and Maintenance Expense shall equal Distribution Operation and Maintenance Expenses multiplied by the Primary Distribution Plant Allocation Factor.

H. Distribution Related Administrative and General Expenses shall equal the sum of (1) Distribution Provider's Administrative and General Expenses multiplied by the Distribution Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Distribution Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State Distribution related expenses or assessments, plus specific Distribution related expenses included in Account 930.1. This sum shall be multiplied by the Primary Distribution Plant Allocation Factor.

I. Distribution Rents Received from Electric Property shall equal any Account 454 Rents from electric property associated with Distribution Plant multiplied by the Primary Distribution Plant Allocation Factor.

EXHIBIT 1

CUSTOMER'S POINTS OF DELIVERY

* 1. **Logan International Airport,** East Boston, MA as shown on Logan International Airport 2005 General Location Plan, dated August, 2005, connected at 13.8 kV.

* 2. **Hanscom Field,** Bedford, MA as shown on L.G. Hanscom Field 2005 General Location Plan, dated August, 2005, connected at 4.16 kV.

* 3. **Black Falcon Cruise Terminal,** South Boston, MA as shown on Black Falcon Cruise Terminal Facility Layout, dated August, 2004, connected at 13.8 kV.

4. **Conley Marine Terminal,** South Boston, MA as shown on Conley Marine Terminal Facility Layout, dated August, 2004, connected at 13.8 kV.

5. **Moran/Autoport Terminal,** Charlestown, MA as shown on Massport Tobin Bridge & Moran Facilities Layout, dated August, 2005, connected at 13.8 kV.

* These Points of Delivery provide essential life safety services.

Information Request EFSB-RR-2 (Tr. 1, at 43)

Refer to Exhibit EFSB-N-19, part c. Please provide the total peak demand in 2023 within the East Boston-Chelsea-Lynn load area as forecasted in the 2015 ISO-NE CELT Report. Please clarify the treatment of the GE Lynn Substation load in that calculation. Confirm whether or not the GE Lynn Substation load was modeled at its full potential load or net of its local generation.

Response

The table below provides the 2023 peak demand within the East Boston-Chelsea-Lynn area as forecasted in the 2015 ISO-NE CELT Report. In the 2015 ISO-NE CELT Report, the GE Lynn load is forecasted to be 31 MW. This is the full potential load, i.e., assuming the GE Lynn generation is not running.

	Chelsea/ East Boston	Revere/Lynn	GE Lynn	totals
	2023 (MW)	2023 (MW)	2023 MW	2023 (MW)
Peak demand	152.29	186.86	31	370.15
Active demand response	-1.18	-1.75	0	-2.93
Passive demand response	-12.02	-17.79	0	-29.81
Energy efficiency forecast	-5.62	-8.31	0	-13.93
Net demand	133.47	159.01	31	**323.48**

Information Request EFSB-RR-3 (Tr. 1, at 51)

Please summarize the Company's best and most recent estimates of the amount of load that would be interrupted in the Chelsea-East Boston-Lynn load area in 2018 and 2023 following the contingencies of concern. Specifically, please outline the Company's assumptions for whether the calculation should use net load or gross load, and compare that assumption to the ISO-NE interruption guidelines.

Response

The table below provides the 2018 and 2023 loading for the Chelsea-East Boston-Lynn load area based upon the 2015 CELT Report.

	Chelsea/ East Boston		Revere/Lynn		total	
	2018 (MW)	2023 (MW)	2018 (MW)	2023 (MW)	2018 (MW)	2023 (MW)
Peak demand	142.3	152.29	193.7	217.86	**336**	**370.15**
Passive demand response	-12.3	-12.02	-16.8	-17.79	-29.1	-29.81
Energy efficiency forecast	N/A	-5.62	N/A	-8.31	N/A	-13.93
Net demand	130	134.65	176.9	191.76	**306.9**	**326.41**

Whether the calculation is based on net load (net demand in the table above) or gross load (peak demand in the table above), the load that would be interrupted exceeds the ISO-NE 300 MW loss of load criteria. Following the contingency of concern, the passive demand response would trip off-line and the corresponding load at risk would be 336 MW in 2018, increasing to 356.22 MW in 2023.

Note that the Revere/Lynn load shown in the table above includes GE Lynn.

Information Request EFSB-RR-4 (Tr. 1, at 52)

Please provide an updated table for the table originally provided in Exhibit EFSB-N-19(b) showing .historical demand with weather adjustment, reflecting the 27.5-megawatt potential maximum load for the GE Lynn Substation.

Response

The table provided in response to EFSB-RR-5 updates the table originally provided in the Company's response to Information Request EFSB-N-19(b), by reflecting the potential for up to 27.5 MW of load at the General Electric Lynn Substation. Note that in the response to Information Request EFSB-N-19, the Chelsea column was expressed in MVA. The Chelsea Substation peak demand numbers in the table below have been converted to MW in order to be consistent with the Revere and Lynn columns.

	Actual Peak Demand (MW)				
Year	Chelsea	Revere	Lynn	GE Lynn	TOTAL
2005	96.0	58	87.8	27.5	269.3
2006	97.5	61.2	92.3	27.5	278.5
2007	96.1	28.1	81.1	27.5	232.8
2008	87.7	47.8	72.6	27.5	235.6
2009	114.6	47.1	82.9	27.5	272.1
2010	116.8	48.5	87	27.5	279.8
2011	119.6	53.3	97	27.5	297.4
2012	116.6	50.8	91.5	27.5	286.4
2013	120.1	52.6	100.8	27.5	301.0
2014	108.8	45.6	83.6	27.5	265.5
2015	105.6	42.4	72.9	27.5	248.4

The table provided above and in EFSB-RR-5 represents coincident peaks values. ISO-NE studies and the associated ISO-NE load forecasts given in the ISO-NE CELT Report are used for planning the Regional Transmission System. ISO-NE uses load values that are forecast to occur coincident with the ISO-NE system peak. ISO-NE system peaks typically occur in the mid to late afternoon. The Company uses substation peak load forecasts for evaluating substation capabilities. The Company's substation peak loads do not necessarily occur coincident with ISO-NE peaks. The Company's substation peak forecasts are “non-coincident” peak load projections. For example, in 2015, the actual coincident peak load at Chelsea Substation was 107.8 MVA (105.6 MW) occurring on July 29, 2015 at 5:00 PM, while the non-coincident Chelsea Substation peak was 111.0 MVA (108.8 MW), occurring on September 8, 2015 at 3:00 PM.

Note that the Company plans its system to accommodate demand at the 90/10 peak weather condition, as does ISO-NE. The 90/10 weather condition is defined as weather that is expected to occur once in every 10 years. The Company historically has found that planning to accommodate the 90/10 weather condition is a reasonable and prudent basis for meeting the demands of our customers. If the Company planned to the 50/50 weather conditions, there would be insufficient capacity to meet demands on the hottest days of the year during that 90/10 condition.

The region experienced two 90/10 weather conditions (defined as THI of 85.5) in the past ten years: in 2011 and again in 2013. In those two 90/10 years, the peak load was just under or just over 300 MW, as shown on the table. Thus, there is historical evidence that demand in the Chelsea/Revere/Lynn load pocket is at the 300 MW level during 90/10 weather conditions.

The table also demonstrates that load varies from year to year. The load grows or contracts in accordance with the overall regional economy, the local economy, customer behavior, and weather patterns. Weather patterns include not only variation in heat and humidity, but timing and duration of heat spells. For example, for a given 90/10 weather condition, customers tend to consume more electricity on peak days at the peak hour when it occurs in the context of an extended heat wave, and customers tend to consume less electricity when that peak is experienced as an isolated event or in September rather than July or August.

The decrease in load between 2013 and 2015 is most likely due to a number of factors, but chief amongst them is that these years were unusually cool and had unusual load occurrence (i.e., the peak day occurred in September rather than August). The decrease in load was not due to sustained economic contraction or any other variable that would persist over time. To the contrary, the local and regional economy is expected to grow in coming years, as evidenced by the major customer contracts now in the queue in this area and the new residential and commercial buildings under construction that can be readily observed. Accordingly, there is every reason to expect that, when 90/10 weather is next experienced, the load will exceed the levels experienced in 2011 and

2013 -- as is predicted in the forecasts of both the ISO-NE and the Company.

Information Request EFSB-RR-5 (Tr. 1, at 72)

Refer to the table in Exhibit EFSB-N-19(b): (a) Please update the table to reflect the weather-adjusted actual demand for the years 2005-2015 using 90/10 weather conditions. In addition, include an additional column providing the total demand for the three substations. Include the 27.5-MW potential maximum load for the GE Lynn Substation, and confirm that no numbers are double-counted. (b) Explain the methodology that was used to calculate the weather-adjusted numbers. (c) Compare the 2015 weather-adjusted total demand with the 2018 forecasted total demand. Explain any gaps that may exist between 2015 and 2018. Explain why the Company believes it is reasonable that the difference in load will be achieved between 2015 and 2018. Include the 2.6 MVA of delayed customer load as part of your answer.

Response

a. Attached is the table updating the table originally provided in the response to Information Request EFSB-N-19(b), reflecting the following changes:

- Addition of a 90/10 weather-adjusted demand estimate for Chelsea Substation (Note: no changes were made to Revere and Lynn, as National Grid's response to Information Request EFSB-N-19(b) already represented a 90/10 adjustment for those substations).
- Addition of the potential for up to 27.5 MW of load at the General Electric Lynn Substation. [The company confirms that there are no double counts in the table below.]

Table EFSB-RR-5 A

	Actual Peak Demand (MW)					Weather Adjusted 90/10 (MW)				
Year	Chelsea	Revere	Lynn	GE Lynn	**TOTAL**	Chelsea Adjusted	Revere Adjusted	Lynn Adjusted	GE Lynn	**TOTAL**
2005	96.0	58	87.8	27.5	**269.3**	99.6	59.4	89.9	27.5	**276.4**
2006	97.5	61.2	92.3	27.5	**278.5**	97.1	61.1	92.2	27.5	**277.9**
2007	96.1	28.1	81.1	27.5	**232.8**	99.2	30.6	88.3	27.5	**245.6**
2008	87.7	47.8	72.6	27.5	**235.6**	94.8	51.1	77.6	27.5	**251.0**
2009	114.6	47.1	82.9	27.5	**272.1**	121.1	52.2	91.9	27.5	**292.7**
2010	116.8	48.5	87	27.5	**279.8**	119.9	50.9	91.2	27.5	**289.5**
2011	119.6	53.3	97	27.5	**297.4**	119.8	53.7	97.6	27.5	**298.6**
2012	116.6	50.8	91.5	27.5	**286.4**	121.1	54.4	97.9	27.5	**300.9**
2013	120.1	52.6	100.8	27.5	**301.0**	121.1	53.1	101.7	27.5	**303.4**
2014	108.8	45.6	83.6	27.5	**265.5**	115.6	50.2	92	27.5	**285.3**
2015	105.6	42.4	72.9	27.5	**248.4**	112.6	46.2	79.5	27.5	**265.8**

Please note that this table is based on coincident peak values.

b. The basis for the Company’s weather normalization methodology begins at the operating company level. The weather normalized summer peak value for each of the operating companies is derived using econometric forecast models that estimate the historical relationship between actual peak load data and weather. The weather variables used in this analysis include heating degree days for the winter months and temperature and humidity indexes (THI) for the summer months.

The econometric analysis produces weather coefficients for both winter and summer months. (A coefficient is a measure of the relationship between two variables, in this case weather and peak load). The amount of weather impact for any given year is derived by calculating the variance between the expected normal weather and the actual weather, and multiplying the results by the weather coefficient.

Note:

- Normal “50/50” weather is defined as the average weather on the past 10 annual peak days.
- Extreme (90/10) weather is defined as a weather that is expected to occur once in every 10 years.

In deriving the weather impact at the substation level, the Company assumes the same percent change relationship between the weather adjusted peak load and actual peak load experienced at the operating company level. For example, if for a given year the percent change between the operating company peak load and weather adjusted peak load was 5.0%, the Company makes the assumption that that same relationship will exist at the substation.

The Company's substation weather normalization process is its best estimate of the impact of weather conditions at the substation. Please note however that analytically derived weather normalization can only be roughly estimated at the substation level due to the following factors: (1) The analysis uses coefficients that were developed at the territory level (Boston Edison Company). (2) Chelsea Substation demand represents just 3.5% of the Boston Edison Company system peak. (3) While the 2015 Boston Edison Company territory and Chelsea peak demands did occur on the same month, day, and day type, they occurred at different times, suggesting that weather variables used in developing Boston Edison

Company weather coefficients are not completely representative of the Chelsea Substation. (4) A comparison of the historical peak demand shows that the Boston Edison and Chelsea Substation peaks have generally occurred on different months, days, day types and time, suggesting again that for those years where there are these differences, a weather normalization analysis at the substation level provides only an approximation.

Given the much less than extreme 90/10 weather conditions experienced in the summer of 2105, and the late date of the peak (the peak in 2015 occurred in September, only the 2nd time in 40 years that has occurred) the Company considers 2015 an outlier, in which the normal weather adjustment methodology employed by the Company is not likely to return a reliable estimate.

For this reason, for planning purposes the Company feels that it is reasonable to also take into account actual demand experienced under similar extreme 90/10 weather conditions.

As stated in the Company's response to Information Request EFSB-N-22(R-1), actual loads at the Chelsea Substation reached 123.7 MVA in 2013 and 123.3 MVA in 2011, under conditions that were comparable, but less severe than the extreme conditions in the Company’s forecast.

Based on this recent history, and the future step load associated with major planned customer projects, the Company believes that the existing Chelsea Substation capacity is not sufficient to meet expected demand under extreme weather conditions in the Chelsea/East Boston area.

c. The table below shows a comparison of 2015 weather-adjusted total demand with the 2018 forecast total demand.

NSTAR Chelsea Substation Peak Demand (MVA)

2015:	
2015 Weather Adjusted Peak Demand	114.9
Expected Step Load Not Realized	2.6
Net 2015 Peak Demand	**117.5**

2018	
Gross 2018 Forecasted Peak Demand	139.4
Less Energy Efficiency	4.9
Less DG_Solar	0.2
Plus Step Load	11.8
Net 2018 Forecasted Peak Demand	**146.2**

Due to the very unusual weather conditions in 2015 and the difficulty in providing weather normalization results at the substation level, the Company believes that the estimated Net 2015 Peak Demand of 117.5 noted in the table above is understated, given that this is lower than the actual peak of 123.7 MVA reached in 2013 under slightly less severe 90/10 conditions. The Company believes it is reasonable to assume that a similar peak will be reached again in the future and that it needs to plan for that eventuality.

For that reason, the Company has prepared the following scenario analysis, using the 2013 peak as a proxy for the 2015 peak:

90/10 Scenario Analyais _ 2018 NSTAR Chelsea Substation Peak Demand (MVA)

Note:2013 Actual Chelsea Peak Demand 123.7 MVA

Assuming a proxy for 2015 90/10 starting point (see note 1)	123.7
Estimated Economic growth from 2013 through 2015	3.0
Expected Economic growth 2015 through 2018	7.0
Less Energy Efficiency	2.4
Less DG Solar	0.1
Plus Step Load	11.8
Net 2018 Estimated Peak Demand	143.0

NOTE:
1. Using 2013 peak as proxy, weather conditions were close to extreme weather (90/10) condition.
2. Expected Economic growth - defined as the change (2018 vs 2015) in Chelsea forecast presented in EFSB-N-5, and estimated growth 2013 through 2015
3. Energy efficiency - defined as the change (2018 vs 2015) in EE presented in EFSB-N-6
4. DG Solar - defined as the change (2018 vs 2015) in DG presented in EFSB-N-7
5. Step Load -for large customer projects as presented in EFSB-N-8

This scenario analysis validates the Company's forecasted peak demand; starting with the most recent 90/10 year and adding in expected economic growth, the result is within -2% of the Company's 2018 Forecast.

The Company believes it is reasonable to expect the growth in load between 2015 and 2018 to be achieved, for the following reasons:

Economic growth can be expected in the time period between 2015 and 2018. The Company’s forecast incorporates a future expected economic growth rate of 2.7% (source: Moody’s Analytics, an internationally recognized provider of economic data).

Additional step load of 11.8 MVA for several large customer projects is expected to come on line by 2018.

Factoring in future economic growth, the step load due to large planned customer projects, and recent peak levels at the Chelsea Substation under 90/10 extreme conditions, the Company believes it is reasonable to assume that it will achieve the increase in load between 2015 and 2018.

Information Request EFSB-RR-6 (Tr. 1, at 92)

Refer to the table in Exhibit CF-44 and Record Request EFSB-RR-5. Please update the "Difference (%)" column to reflect changes made to the table in Exhibit EFSB-N-19, part b, based on 90/10 weather-adjusted historical demand for Chelsea Substation.

Response

See updated table below.

Year	"90/10" (Extreme Weather) Load Forecast (MVA)	Actual Summer Peak Load (MVA) 90/10 Weather Adjusted	Difference (%)
2008	98.3	94.1	-4.2%
2009	110.5	123.6	11.9%
2010	122.3	123.7	1.2%
2011	123.0	123.5	0.4%
2012	123.1	123.9	0.6%
2013	126.9	124.7	-1.7%
2014	126.5	124.5	-1.6%
2015	134.8	119.1	-11.6%

The table above is based on non-coincident peak demand. For the Company’s substation planning purposes, the non-coincident peak is a more appropriate measure than coincident peak as it refers to the peak at the individual substation level.

ISO-NE studies such as the 2015 Updated Needs Assessment, which evaluate the performance of the transmission system, are based on coincident system peaks, a more appropriate measure supporting regional transmission analysis.

For that reason, the Company's responses to Information Requests EFSB-N-19, EFSB-RR-4 and EFSB-RR-5 are based on coincident peaks, and will differ from the data presented above.

As shown in the above table, the forecasts for Chelsea Station and the Company's responses to Information Requests were generally within +/- 5% of the estimated load normalized for extreme weather conditions, with the exception of 2009 and 2015.

As stated in the Company's response to EFSB-RR-5, because the forecast was developed at the territory level, any methodology to weather adjust the substation loading would provide only a rough estimate.

Additionally, the Company considers 2009 and 2015 to be outliers, given the unusual weather conditions experienced in those years. Most recently, the weather conditions that occurred on the summer of 2015 peak were much less severe than 90/10 extreme conditions.

Another factor that may have contributed to the lower actual peak load in 2015 is the late date of the peak. The peak in 2015 occurred in September – only the second time in 40 years that the peak occurred in September. With the peak occurring late in the season, customer behavior may have contributed to the lower peak (for example, residential window air conditioning units may have already been removed).

Given the unusual weather conditions in 2015, the Company does not believe that its weather normalization methodology provides a reasonable estimate, nor that the 2015 90/10 weather adjusted value of 119.1 MVA in the table above is understated.

As stated in the Company's response to Information Request EFSB-N-22 (R-1), actual loads at Chelsea Substation were 123.7 MVA and 123.3 MVA in 2013 and 2011, respectively, under conditions that were comparable, but slightly less severe than the 90/10 extreme conditions in the Company’s forecast. These values are more consistent with the actual 90/10 extreme weather adjusted results in the above table for years 2009 to 2014 and a more reliable indicator of future loads for planning purposes.

Information Request EFSB-RR-7 (Tr. 1, at 97)

Beginning with the year 2008, please provide tables showing the percentage difference between the Company's annual load forecast and the actual demand measured. Please provide separate tables measuring the percentage difference for (a) the Boston Edison service territory; and (b) the Chelsea Substation. Please correct for any distribution retirements and note any corrections made. If necessary, please elaborate on the use of weather-adjusted values; the impact of the economic recession; and other pertinent factors contributing to the percentage difference between the forecasted and actual values.

Response

a. It is important to note that the Company's annual load forecast is performed for substation transmission planning purposes and is accordingly based on a 90/10 extreme weather forecast; that is, weather that is expected to occur only once in every ten years. Accordingly, it would not be expected that the Company's forecast and actual demand would be the same in any given year.

The tables below provide the percentage difference between the Company's annual load forecast and the actual demand measured for (a) Boston Edison Company; and (b) Chelsea Substation.

Table EF SB-RR-7A : Peak Demand _ F orecast VS Actual _Boston E dison Company (BE CO)

	Forecast Yr							
	2007	2008	2009	2010	2011	2012	2013	2014
2008	2.7%							
2009	10.1%	8.6%						
2010	6.9%	3.8%	6.3%					
2011	4.8%	0.3%	3.6%	-0.7%				
2012	12.9%	6.3%	12.5%	6.8%	5.4%			
2013	11.1%	2.9%	12.4%	5.7%	5.0%	6.4%		
2014	24.0%	13.0%	25.2%	17.7%	18.7%	21.9%	15.4%	
2015	26.8%	13.3%	26.0%	18.9%	21.8%	26.4%	20.4%	13.7%

Table EFSB-RR-7B : Peak Demand Forecast VS Actual _Chelsea Substation								
	Forecast Yr							
	2007	2008	2009	2010	2011	2012	2013	2014
2008	5.9%							
2009	-3.4%	-5.5%						
2010	-6.0%	-7.8%	1.5%					
2011	-7.7%	-9.4%	0.2%	-0.2%				
2012	-3.4%	-5.9%	5.0%	4.5%	3.2%			
2013	-5.8%	-8.9%	1.7%	2.5%	1.9%	2.5%		
2014	0.7%	-3.3%	7.4%	9.6%	10.7%	12.0%	8.1%	
2015	6.8%	1.5%	12.7%	15.6%	18.5%	20.5%	16.3%	20.7%

The one correction made to the data is accounting for 15 MVA of load that was transferred to the Chelsea Substation prior to the peak of 2009. The underlying assumptions for the economy, the energy efficiency and step loads vary between forecast.

The comparison above is based on actual results versus forecast and have not been weather normalized.

Factors that can affect the variance between actual results and forecasted estimates include:

- Weather - actual vs extreme 90/10; duration (# of days of heat wave) and timing (month) of peak weather events
- Economic conditions – actual vs projected economic conditions (source for the forecast: Moody's Analytics).

For illustrative purposes, Table EFSB-RR-7C below compares actual weather conditions in Boston (based on THI) for the years 2008 through 2015.

Table EFSB-RR-7C - Weather Analysis				
	Actual THI Boston	90/10 THI	Difference	Percent
2008	81.0	85.5	-4.51	-5.3%
2009	82.2	85.5	-3.31	-3.9%
2010	80.6	85.5	-4.86	-5.7%
2011	85.4	85.5	-0.06	-0.1%
2012	83.3	85.5	-2.16	-2.5%
2013	85.2	85.5	-0.26	-0.3%
2014	82.0	85.5	-3.51	-4.1%
2015	80.4	85.5	-5.06	-5.9%

The analysis captured in both tables EFSB-RR-7A and EFSB-RR-7C shows that for those years where the difference between actual and 90/10 weather conditions is large, there is a larger percent difference between the forecast peak load and actual peaks.

For the years 2011 and 2013, weather conditions were close to the extreme 90/10 estimate. In those years, actual peak results were relatively close to the forecast.

Information Request EFSB-RR-8 (Tr. 1, at 115)

Refer to EFSB-N-22, part b. Please provide the 2015 actual load (MVA) at Chelsea Substation that is weather-adjusted to reflect 90/10 weather conditions.

Response

The 2015 actual non-coincident peak demand (MVA) at Chelsea Substation #488 was 111.7 MVA. The estimated 90/10 weather adjusted peak demand would be 119.1 MVA.

Information Request EFSB-RR-9 (Tr. 1, at 116)

Refer to EFSB-N-22. For the Chelsea Substation, please provide a comparison between the 90/10 weather-adjusted 2015 load forecast value-provided in part (a) (133.6 MVA) with the sum of the 2015 actual load value weather-adjusted under 90/10 conditions (to be provided in Exhibit EFSB-RR-8) plus the 2.6 MVA of delayed customer connections. Provide a narrative explaining any differences between those two figures, and explain why the Company believes its forecast does not need to be revised in light of the 2015 actual load value.

Response

The table below shows the comparison between the 90/10 weather adjusted 2015 peak demand and the 2015 forecast produced by the Company.

NSTAR Chelsea Substation Peak Demand (MVA)	
2015 Estimated Weather Adjusted Peak Demand	119.1
Expected Step Load Not Realized	2.6
Net 2015 Estimated Peak Demand	121.7
2015 Forecasted Peak Demand	133.6
Delta	11.90
Percent Delta	9.8%

The Company believes that the difference between the 2015 weather adjusted peak demand and the 2015 forecast is attributable to the following factors:

The weather in 2015 was an outlier, given that the weather conditions that occurred on the summer of 2015 peak demand day were much less severe than 90/10 extreme conditions.

Another factor contributing to the lower actual peak load in 2015 is the late date of the peak. The peak in 2015 occurred in September – only the second time in 40 years that the peak occurred in September. With the peak occurring late in the season, customer behavior may have contributed to the lower peak (for example, residential window air conditioning units may have already been removed).

Lastly, the Company considers weather normalization at the substation level a rough estimate at best, as noted in the response to Record Request EFSB-RR-5.

The Company bases its transmission and substation planning on 90/10 extreme weather forecasts. Because of the factors noted above related to the inherent weaknesses of using weather normalization, the Company does not use the weather normalized peak for planning purposes. In this case, recent history demonstrates that peak demands under extreme weather conditions were higher than the estimated weather normalized peak for 2015.

As referenced in the Company's response to Information Request EFSB-N-22, actual loads at the Chelsea Substation reached 123.7 MVA in 2013 and 123.3 MVA in 2011, under conditions that were comparable, but less severe than the extreme conditions in the Company's forecast.

The Company does not believe that a new forecast is needed, for the following reasons:

The Company's forecast is developed at the territory level, based on sound econometric modeling and forecasting methodologies. It is the Company's best expectation of future outcomes.

The Company develops its forecast using the following methodology:

The Company forecasts electrical load independently for each of its operating regions because of the unique characteristics of each region.

The forecast is based on the relationship between the past 10 years of historical data for actual peak loads, weather and regional economic variables. This relationship is expressed in the forecast model as a coefficient, or measure of the relationship between these variables.

Based on these estimated historical relationships, each company's operating region's peak forecast is based upon regional economic variables and the temperature humidity index ("THI") using standard regression analysis. Forecasts are developed by simulating the estimated historic relationship between the operating region's peak trend and the THI under extreme 90/10 weather assumptions.

The regional economic assumptions used in the Company peak demand models include variables such as real income per capita, real income per household, number of households and gross metro product. Historical data and forecasts of economic drivers are procured from Moody's Analytics, an international economic consulting company.

The Company uses a software package called E-views, a product of IHS as its statistical tool. IHS is a leading global source of statistical software, and has been a developer of statistical software for over twenty-five years. IHS statistical products are utilized by academic researchers, corporations, government agencies, and companies such as utilities. The EViews tool has an established reputation as a worldwide leader in Windows-based econometric and forecasting software.

Each operating region's forecast is initially produced through econometric regression equations without consideration of additional energy efficiency programs. After the peak forecast is produced for each operating region, projected incremental energy efficiency is subtracted from the peak demand forecast

After the regional forecast is complete, each substation's forecasted peak load is estimated based on the relationship between the substation's actual historical peaks and the relevant operating company's peak load (history and forecast).

Manual adjustments are made to individual substation forecasts for specific, identified large development projects and expected changes in system operations that could not otherwise be predicted by the operating company econometric forecasts or the individual substations' share of those forecasts and Furthermore, in compliance with the Department's guidance in DPU 13-86, the Company has amended its load forecasting methodology both to align with ISO-NE and change how it reconstitutes loads for distributed generation.

Please refer to the page 2-11R of the Analysis (Exhibit EV-2) for a more detailed discussion of the Company's load forecasting methodology.

Please keep in mind that any forecast can provide only a reasonable range of future outcomes, based on historical relationships and the best estimate available of future indicators (such as economic growth). The Company believes that it has a proven track record of forecast accuracy, within a reasonable margin of error. The Company considers the 2015 peak at the Chelsea Substation to be an outlier, based on significantly less severe weather conditions than extreme 90/10 and the late calendar date of the peak. The Chelsea Substation did in fact reach MVA of 123.7 and 123.3 in 2013 and 2011 respectively, under conditions that were comparable, but less severe than the extreme conditions in the Company's forecast in 2015.

Based on this recent history, and the future step load associated with planned customer projects, the Company believes that the existing Chelsea Substation capacity is not sufficient to meet potential future demand under extreme weather conditions in the Chelsea/East Boston area.

Information Request EFSB-RR-10 (Tr. 1, at 141)

a) Please provide further information regarding a likely or practical peak load reduction target for energy efficiency programs in the Chelsea-East Boston area; b) Please elaborate on the discrepancy between the Company's statement in Exhibit EFSB-1 regarding a 15 percent peak load reduction from energy efficiency in the Mystic-Woburn area and the Company's statement in Exhibit EFSB-PA-17, part E, regarding a less than 11 percent peak load reduction in the Chelsea-East Boston area.

Response

a) The potential for peak load reduction in the Chelsea-East Boston area is best estimated by referencing statewide peak load (approximately 11,000 MW) and statewide energy efficiency goals for peak demand reduction (approximately 600 MW over three years 2016-2018, or 200 MW/year). This results in a potential for approximately 2%/year reduction in peak load due to energy efficiency efforts. Other factors, most notably weather and economic conditions, also affect peak loads and could either offset or compound a 2%/year energy efficiency impact. For example, a 2% peak load reduction due to efficiency, combined with a 2% peak load increase due to economic conditions, would result in no net load reduction.

   Furthermore, statewide numbers do not perfectly represent every city, town and neighborhood in the state. The variables that affect where the energy efficiency measures are installed are numerous: current efficiency of customers' homes and businesses, individual customer appetite for capital investment, suitability of efficiency technology to customer needs, etc.

   The Company already aggressively pursues energy efficiency opportunities throughout its service territory, including in the Chelsea-East Boston area. To develop a more precise estimate of the peak demand reduction opportunity for this specific area would require an impractical level of customer input, customer financial commitment, and to the extent demand reduction measures require changes in customers' business, customer commitment to operational change.

b) The 15% peak reduction referenced in Exhibit EFSB-1 is the percentage reduction used by London Economics International ("LEI") in its analysis of non-transmission alternatives to Eversource's Mystic to Woburn Transmission Project. As stated in

EFSB-1, "LEI assumed that at most, 15% of the peak load can be expected to be reduced using new energy efficiency measures" (emphasis added). The Company believes this is an upper limit assumption meant to challenge the suitability of traditional solutions when compared to NTAs, and not meant to represent the likely reduction potential. Furthermore, as noted in the footnote on Exhibit EFSB-1, "according to the Utilities, achieving peak load reductions from energy efficiency of 15% over and above levels achieved through state-mandated programs is a goal that goes well beyond utility geo-targeting experiences to date." The footnote goes on to discuss recent geo-targeting efforts that have resulted in less than 3% reductions. Also see Attachment EFSB-RR-10(1), which provides additional pages (highlighting added) from the same LEI report from which pages were extracted for Exhibit EFSB-1. LEI reiterates that "achieving peak load reductions from energy efficiency of 15% over and above levels achieved through state-mandated programs is a goal that goes well beyond utility geo-targeting experiences to date." In addition, LEI states that the assumption that energy efficiency can at most reduce peak load by 15% assumes a participation rate close to 100% at any given injection location. Lastly, LEI notes that 15% is an aggressive assumption considering the significant existing energy efficiency programs in Massachusetts. The 11% referenced in the Company's response to Information Request PA-17 represents the amount of incremental energy efficiency necessary to defer the need for the substation. However the Company believes that obtaining this level of energy efficiency targeted in the Chelsea -East Boston area is not realistic.

assumptions on the technical and operational characteristics of NTA technologies and how these relate to the contingency event and CLL are described in Appendix B.

In light of the requirements defined by these contingency events, Step B selects NTA technologies that are able to respond within the time-frame required, and are able to continue injecting energy reliably for the duration required by these contingency events.

Step C: Locational

The last step further refines this list of technically feasible NTA technologies by using locational considerations at each injection location for each Case. For two specific NTA technologies - active demand response and passive demand response (energy efficiency), this step of the methodology compares the total load (MW demand) at each injection location against the NTA requirement at that location. This comparison reveals whether a particular location has sufficient demand that can be curtailed either through active demand response or by implementing new energy efficiency measures so that the NTA requirement at that location can be met. The underlying assumption is that up to 15% of peak load at any given location can be reduced using new energy efficiency programs. This parameter was developed in conjunction with the Utilities. Achieving peak load reductions from energy efficiency of 15% over and above levels achieved through state-mandated programs is a goal that goes well beyond utility geo-targeting experiences to date. Eversource's Marshfield Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW of this load reduction. Similarly, National Grid's ongoing Tiverton/Little Compton Pilot targets load reductions of 1 MW (out of a total peak load of 20 MW) through a combination of energy efficiency and demand response. At the end of the 2014 (the third year of the pilot), approximately 566 kW of load reductions had been achieved, with approximately 426 kW coming from energy efficiency.

The results of this three-step methodology were then used as direct inputs into the cost analysis.

4.3 Methodology for estimating cost of technically feasible NTA technologies

LEI employed industry-standard levelized costing principles to the identified pool of technically feasible NTA technologies from step 3 above in order to estimate the total cost of implementing the least cost technically feasible NTA technologies for each hypothetical NTA case (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW cases). For each selected technology, LEI estimated a gross LCOE which, represents a resource' all-in-costs, levelized over its life cycle. The gross LCOE is a per kilowatt per year figure ($/kW-year) that embodies all costs including capital costs, going-forward FOM costs, as well as fuel and VOM costs. The gross LCOE represents a long term timeframe that is consistent with the requirements identified at each injection point. As a next step, LEI derived Net LCOE for each technology by deducting from gross LCOE a bundle of potential revenue streams associated with each NTA technology. The analysis then consisted of multiplying at each injection point the net LCOEs of all feasible technologies by the NTA capacity requirements (adjusted for performance and availability). The least cost technically feasible NTA technologies were selected at each location by comparing the products of net LCOEs and NTA capacity requirements across all feasible technologies. Finally, we

Figure 21. Amount of NTA requirements by case and technically feasible NTA technology for the AC Solution

	AC Solution MW Injections					
	Pmax = 15		Pmax = 250		Pmax = 750	
NTA Resource	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)	N-1 (MW)	N-1-1 (MW)
Combined Cycle Gas Turbine (CCGT)	0	0	250	1606	259	2215
Peaker Aeroderivative Unit	791	2314	6	899	0	1007
Peaker Frame Unit	0	0	0	0	0	0
Dual-fuel Jet Engine	716	1924	0	132	0	135
Solar Utility Scale (with storage)	791	2314	6	126	33	194
Solar Utility Scale	0	0	0	0	0	0
Solar DG with storage	0	0	0	0	0	0.7
Solar DG	0	0	0	0	0	0
Fast Discharge Battery	0	0	0	0	0	0
Slow Discharge Battery	791	2314	92	899	33	1152
Active DR - Emergency Generation	0	0	0	0	0	0
Passive DR (Energy Efficiency)	75	154	0	27	0	1
Cumulative NTA resource requirements provided by Utilities	791	2314	342	2504	292	3118

Note: The N-1-1 MW are incremental, not inclusive of N-1 MW amount.

The last row of the figure provides the total MWs required from a technically feasible NTA solution (for N-1 and N-1-1 contingency events). As can be seen, under the N-1-1 event for Pmax 15 MW case, for example, peaker aeroderivative units, slow discharge batteries and utility scale solar PV (with storage) can each meet the cumulative NTA resource needs. The final choice regarding of these NTA technologies will be selected for the cost analysis at each injection location will be determined on the basis of each technology's net levelized costs (net LCOE).

The results presented above incorporate the assumption that energy efficiency can at most reduce peak load by 15% (assuming a participation rate close to 100%) at any given injection location, which restricts the amount of energy efficiency that can qualify as a technically feasible NTA technology at many locations.

Other small scale NTA technologies, such as distributed solar generation ("solar DG"), cannot effectively meet the technical requirements of the contingencies and the sizing required of hypothetical NTA requirements at several locations. For example, solar DG resources have an operating profile that does not provide for the sustained performance required under N-1 and N-1-1 contingency events. Even if solar DG were to be paired with energy storage technologies (battery) to overcome the intermittency of operation, LEI's methodology was able to qualify solar DG units as technically feasible NTA technology at just one location each under the medium and large scale NTA case that required only 0.1 MW and 0.7 MW of NTA injections respectively.[22] Specifically, in Massachusetts, a solar DG unit is conventionally defined as less than 5 MW of nameplate capacity and exhibits an average performance rate of 15%[23], implying that a 5 MW unit would only produce 0.75 MW of energy on

[22] The 0.1MW of solar DG injection is not shown in Figure 21 because of rounding.

[23] We assumed an annual average capacity factor of 15% for solar PV in Massachusetts based on modeling results as documented in NREL's System Advisor Model. An annual average capacity factor of 15% is consistent with the state of Massachusetts' estimated solar PV's capacity factor of 13% (see "SREC project calculation", Massachusetts Energy and Environmental Affairs – Department of Energy Resources). It is worth noting that the annual average capacity factor that is

The Utilities estimated at 15% the maximum percentage of peak load reduction achievable at a given location through incremental new programs.[26] Therefore, in the analysis, only locations that have injection requirements smaller than 15% of the peak load at those locations would be available for new energy efficiency. For example, if a location has a peak load forecast of 80 MW, then given the ability of energy efficiency programs to reduce peak load by 15% (taking into account existing and already planned energy efficiency programs), only 12 MW will be available as a technically feasible NTA. Therefore, if the NTA requirement at that location is greater than 12 MW, energy efficiency will not qualify as a technically feasible NTA technology at that location.

It is important to note that energy efficiency, while traditionally considered a small-scale NTA technology, does not qualify as a technically feasible NTA technology as frequently as expected because the load available at each substation is frequently too small to provide enough energy efficiency savings as to meet the required NTA MWs at that location. We assume that peak load at any substation could be reduced by up to 15% through maximum participation in *new* energy efficiency programs - incremental to those assumed in the ISO-NE CELT forecast. This is already an aggressive assumption considering the significant existing energy efficiency programs in Massachusetts. In order for energy efficiency to become feasible at more locations, a higher penetration percentage would be required. LEI conducted a hypothetical test and determined that more than 55% of the peak load would need to be reduced in order for energy efficiency to work as a technically feasible NTA at just 50% of all locations under the Pmax 15 MW case. 55% is obviously an unrealistic target for any new energy efficiency program, and highlights the practical difficulties of implementing new energy efficiency programs to provide for technically feasible NTA solutions.

5.2 Cost estimates

The goal of the cost analysis is to evaluate the net direct cost of implementing NTA technologies for ratepayers as opposed to building the AC Solution. The analysis begins with the evaluation of total cost of technically feasible technologies based on gross LCOE and nameplate capacity, followed by a net LCOE analysis which leads to an estimate of the net direct costs to ratepayers.

5.2.1 Gross cost estimates for ratepayers

Under the base line gross LCOE, gross cost for ratepayers is estimated to range between $1,378 million and $1,471 million a year across the three cases (Pmax 15 MW, Pmax 250 MW and Pmax 750 MW). When adding a +/- 20% sensitivity, the resulting gross direct cost falls within a range of $1,102 million to $1,765 million a year. The cost analysis was done across all considered cases (Pmax 15 MW, Pmax 250 MW, and Pmax 750 MW cases); for each injection point, under a given case, we calculated the total cost for all identified technically feasible NTA technologies based on the combination of their

[26] According to the Utilities, achieving peak load reductions from energy efficiency of 15% *over and above levels achieved through state-mandated program*s is a goal that goes well beyond utility geo-targeting experiences to date. Eversource's Marshfield Distribution Relief Pilot (a targeted attempt to reduce 2 MW of demand on key circuits/substations through a combination of energy efficiency, direct load control, and solar PV installation) resulted in actual kW reductions of approximately 715 kW – less than 3% of peak day afternoon loads of 25,000 – 30,000 kW on the affected lines. Energy efficiency contributed only 320 kW of this load reduction. Similarly, National Grid's ongoing Tiverton/Little Compton Pilot targets load reductions of 1 MW (out of a total peak load of 20 MW) through a combination of energy efficiency and demand response. At the end of the 2014 (the third year of the pilot), approximately 566 kW of load reductions had been achieved, with approximately 426 kW coming from energy efficiency.

Information Request EFSB-RR-11 (Tr. 1, at 145)

Refer to Exhibit EFSB-PA-17. How much incremental energy efficiency, distributed generation or energy storage would be required to address the identified need for additional capacity at the Chelsea Substation, specifically, to reduce the Substation's load to below the 75 percent of normal rating criterion. What is the Company's position regarding the cost-effectiveness or feasibility of such a solution.

Response

To support the Company's need to supply customers during distribution circuit outages while maintaining the loading of the transformers to the 75% normal rating criterion, approximately 10.3 MVA of load relief would be required at Chelsea Station. As explained below, this represents the combined amount by which the transformers at Chelsea Station are forecast to exceed 75% of their normal rating.

As discussed in the Company's response to Information Request EFSB-N-8, on July 19, 2013, the loading of the Chelsea Station Transformer 110C at 47.4 MVA exceeded 75% of the transformer's normal rating (46.9 MVA).

The Chelsea Station Transformer 110C supplies the combined loading of 14-kV bus sections #3 and #4. Transformer 110A supplies the 14-kV bus section #1 and Transformer 110B supplies the 14-kV bus section #2.

Based upon the load forecast provided in the Company's response to Information Request EFSB-N-5, by 2018 the Company is projecting that all of the Chelsea Station transformers will be out of compliance with the 75% of normal rating criterion, exceeding the transformers' combined 75% normal rating by 5.3 MVA, as follows:

- The loading of the Chelsea Transformer 110C is projected to increase to 51.4 MVA, exceeding the transformer's 75% normal rating by 4.5 MVA.
- The loading of the Chelsea Transformer 110A is projected to increase to 47.5 MVA; exceeding the transformer's 75% normal rating by 0.6 MVA.
- The loading of the Chelsea Transformer 110B is projected to increase to 47.1 MVA; exceeding the transformer's 75% normal rating by 0.2 MVA.

The above described loading is considered a "balanced" load profile for the Chelsea Station transformers with all distribution lines and circuits in-service. Should the distribution system experience a loss of a circuit supplied from either the Chelsea Station 14-kV bus section #1 or 14-kV bus section #2, to restore the supply to customers, portions of the affected circuit would be transferred via tie switches to adjacent circuits. It is possible that upwards of 5 MVA of customer load could be transferred to circuits supplied from bus sections #3 and #4, which would increase the loading of the Chelsea Station transformer 110C by 5 MVA, for a combined total of 10.3 MVA above the 75% normal rating of the three transformers.

Solution Effectiveness

Distribution Generation Resources
Based on the above, 10.3 MVA of load within the Chelsea - East Boston supply area would need to be relieved by additional DG resources. To offset this much load at the typical 4-6 p.m. peak demand time would require 3.8 times as much PV nameplate capacity (using the ISO-NE 26% solar capacity adjustment factor). This equates to approximately 39.1 MWs of PV resources.

Considering the urban nature and the availability of land, this amount of additional DG development would be unprecedented. Another consideration is that at 9:00 p.m., the Chelsea Station load level can still reach 95% of the daily peak load and there would be upwards of 5 MVA of load at risk. At 9:00 p.m., the PV output would be so low as to be of no value to mitigate the required load relief.

Targeted Energy Efficiency
Without knowing the specific measures that customers served by the Chelsea Substation would commit to implement and whether those customers would demand incentive levels beyond those in the existing and planned energy efficiency programs, the Company cannot determine whether a targeted energy efficiency solution in this case would be cost-effective.

Energy Storage
Battery storage could conceivably provide a solution to the supply problem at Chelsea Substation, but to get the necessary power and duration to cover the 10.3 MVA of energy storage, batteries would need to have the ability to be recharged in 11 hours or less. The upper limit in discharge duration for suitable batteries would typically be about 6 hours, which does not meet the needs of the Project.

Information Request EFSB-RR-12 (Tr. 1, at 157)

Refer to Petition at 3-10R, paragraph 1, last sentence. Please revise the Company's statement to reflect accurate cost differentials between the proposed Project (Solution #1) and Solutions #2 and #3 that conform to the numbers provided in Table 3-1 of the Petition at page 3-11. Include the calculations used to achieve the correct cost differentials.

Response

The Company's response to Record Request RR-EFSB-16 updated the distribution costs to reflect the longer distribution feeders to integrate Solutions #1, #2 and #3 into the East Boston distribution system. These revised distribution costs were provided in Attachment EFSB-RR-1(1) as Table 3-1(R). Using Table 3-1(R), the Company provides the following calculations for the cost differentials between the Project (Solution #1) and Solutions #2 and #3:

- The cost differential for Solution #2 ($160.8 M) versus the Project (Solution #1 - $116 M):

  Solution #2 is 38.6% more expensive than the Project. (160.8 -116)/116

- The cost differential for Solution #3 ($154.3 M) versus the Project (Solution #1 -- $116 M);

  Solution #3 is 33% more expensive than the Project. (154.3 -116)/116

The Company would like to note that Mr. Bergeron testified that the potential environmental impacts associated with Transmission Alternatives Solution Routes #2 and #3 in comparison to Transmission Alternative Solution #1 were similar (see Tr. 2, 159-160). However, upon a more careful review of these alternatives, it should be noted that, as presented in Table EFSB-PA-11(R-1) in response to EFSB-PA-24, the environmental impacts associated with both Transmission Alternatives Solutions #2 and #3 are greater than associated with Transmission Alternative Solution #1. Solutions #2 and #3 each have greater impacts for four out of the five key environmental factors considered and as such, the Company maintains that Solution #1 is the preferred option over Solutions #2 or #3 from an environmental impact perspective.

Information Request EFSB-RR-13 (Tr. 2, at 194)

Please provide the Company's assessment of the transmission solution it would recommend developing if the East Eagle Street Substation is not approved at this time. Outline the specific, unique facilities needed in order to allow for a potential future connection of the substation. Compare the cost, constructability and environmental impacts of the alternative to the Project as currently proposed. Explain why the Company has identified the particular route and locations as the recommended alternative compared to the Project if the Substation is not developed.

Response

The Company believes the proposed East Eagle Street Substation is needed at this time to address the load growth in the Chelsea-East Boston region. The installation of a 115-kV line from Mystic Substation #250 directly to Chelsea Substation #488 would provide an additional transmission source to supply the East Boston-Chelsea-Lynn load pocket, but would not provide the required substation capacity. Furthermore, the construction of the East Eagle Street Substation is the preferred option to address the substation and distribution needs of the Chelsea-East Boston region. While the Company evaluated the option of installing 75 MVA of firm of transformer capacity at the space-constrained Chelsea Substation, this would provide only 48 MVA of additional capacity. The construction of the East Eagle Street Substation on a vacant parcel avoids the complex station construction that would be required at the Chelsea Substation and provides a more robust solution to address the growing capacity need. The construction of the East Eagle Street Substation would also obviate the potential risk of customer outage that might result during substation construction at the Chelsea Substation. In addition, the East Eagle Street Substation would have inherently superior distribution reliability due to shorter feeders.

If the East Eagle Street Substation were not be approved at this time, the transmission line route selected for the Mystic to Chelsea line would be similar to the preferred route selected for the connection to the East Eagle Substation. At the Chelsea Creek location, a manhole would be installed in the general area to accommodate for the future tie into the existing facilities that cross under the Chelsea Creek and eventual tie into a future East Eagle Substation.

The transmission line costs for this alternative would be less than the Project. With the elimination of the East Eagle Substation connection, the conceptual grade estimate for the line would be approximately $38M (using an approximate $10M per mile cost associated with the Project). The constructability and environmental impacts would be the same as the Project, less those impacts associated with the new substation and trenching associated with the interconnection to the station.

The route selected for this alternative would continue to capitalize upon the existing spare facilities in the area; thereby, minimizing the amount of new excavation required and time duration to complete. The provisions that would be incorporated into this alternative in the area of the Chelsea Creek crossing would allow for a future loop in and loop out of the East Eagle Street Substation with minimal excavation on the north side of the Chelsea Creek crossing. All excavation on the south side of the Chelsea Creek crossing would need to be done as part of the potential future interconnection to the East Eagle Street Substation.

Information Request EFSB-RR-14 (Tr. 2, at 273)

a) Please provide a revised response to Exhibit EFSB-N-7 that is calculated in megawatts ("MW"), not megavolt-amperes ("MVA"); b) Confirm that the values provided in the revised response to Information Request EFSB-N-7 are consistent with the values provided in the response to Information Request EFSB-N-18. If the values are not consistent, compare the Company's Chelsea forecast with the ISO-NE Chelsea forecast and describe the basis for any differences that may exist between the two forecasts.

Response

a) The ISO-NE forecast peak demand levels for Chelsea Substation used in the 2015 Needs Assessment are as follows:

2018: 137.4 MW

2023: 146.2 MW

The following table compares the Chelsea Substation peak demand produced by the Company and by ISO-NE.

ISO-NE Chelsea/East Boston _ 2015 Needs Assessment Forecast		2018	2023
Peak demand (MW)		137.4	146.2

NSTAR Chelsea Forecast_Submitted to ISO-NE March 2013		2018	2023
Chelsea demand (MW)		139.0	147.9
	Less Energy Efficiency	4.9	8.9
Chelsea demand less Energy Efficiency		134.1	139.0
	Plus Step Load	2.5	2.5
Chelsea demand		136.6	141.5

Difference	2018	2023
NSTAR VS ISO-NE	**(0.85)**	**(4.75)**

The methodology used by ISO-NE to develop the CELT forecast can be found in the Company's response to Information Request EFSB-N-7. One factor that may contribute to the difference between ISO-NE's forecast and the Company's forecast is the methodology used to scale the individual substation forecast to the statewide CELT forecast. The Company and ISO-NE use different scaling methods. The ISO-NE scaling methodology is described in Attachment EFSB-N-7(1), while the Company's scaling methodology is described in the Company's response to Information Request EFSB-N-6.

A more recent forecast, prepared in 2014, is presented below:

NSTAR Updated Chelsea Forecast

	2018	2023
Chelsea demand (MW)	136.7	143.9
Less Energy Efficiency	4.8	8.7
Chelsea demand less Energy Efficiency	131.9	135.2
Less DG_Solar Forecast	0.2	0.3
Chelsea demand less Solar Forecast	131.7	135.0
Plus Step Load	11.564	11.6
Chelsea demand	143.2	146.5
Difference	2018	2023
NSTAR VS ISO-NE March 2013	**5.84**	**0.33**

Note: The difference between the Company's forecast submitted in EFSB 14-03/D.P.U and that which was submitted in ISO-NE March 2013 can be attributed to updated assumptions on: (1) economic and weather inputs (2) Energy Efficiency, (3) Solar and (4) Step load.

There are differences between the Company's forecasts provided above and the ISO-NE forecast referenced in the response to Information Request EFSB-N-18. The forecast in EFSB-N-18 does not include 11.6 MW in additional step load for planned large customer projects. Additionally the Company's forecast for substation planning purposes does not include, nor is it appropriate to include, the factors listed on EFSB-N-18 below the Peak Demand line, such as active demand response, and passive demand response.

Also, as referenced in the response to Information Request EFSB-N-7, the forecast methodology that ISO-NE employs is similar to the Company's but may differ in some respects. One of those differences, as referenced in the response to EFSB-RR-6, is that the ISO-NE forecast is based on coincident peaks while the Company's forecast, as appropriate for substation planning purposes, is based on non-coincident peaks at the substation level.

Information Request EFSB-RR-15 (Tr. 2, at 281)

Please indicate what the firm capacity of the Chelsea Substation would be with the addition of a 20-MVA transformer. Discuss the feasibility of accommodating such a transformer at the Chelsea Substation site.

Response

As stated in the Petition at 2-2R and in the Company's response to Information Request EFSB-N-10, Chelsea Station #488 has a station firm capacity of 135 MVA. A 20 MVA 115/14-kV transformer would have a long term emergency rating of 24 MVA. Installing a 20 MVA 115/14-kV transformer at Chelsea Station #488 would increase the station's firm capacity to 159 MVA.

As discussed in Section 3.4.1 of the Petition, the constrained space at Chelsea Substation #488 does not support the expansion necessary to connect a second Mystic-Chelsea 115-kV line, a fourth 115/14-kV transformer, 115-kV circuit breakers, distribution switchgear, 14-kV capacitor bank and a control enclosure. To address the constrained space at Chelsea Substation #488 would require constructing an elevated platform above the energized equipment in the existing six breaker 115-kV AIS ring bus. This construction approach would also be required if a 20 MVA 115/14-kV transformer was used instead of a 62.5 MVA 115/14-kV transformer.

Information Request EFSB-RR-16 (Tr. 2, at 283)

Refer to the Petition at 3-11R, Table 3-1. Please update the estimates for distribution costs for Solutions 1, 2, and 3 to reflect the longer distribution feeder estimate provided in the Company's response to Information Request EFSB-PA-24. If the cost estimate remains unchanged, please explain. If applicable, include any other changes to the cost estimates for Table 3-1.

Response

Please see Attachment EFSB-RR-16(1) for the table that reflects the cost estimates for the longer distribution feeders to integrate the East Eagle Street Station #131 (Solutions #1, #2 and #3) distribution infrastructure system into the East Boston distribution system.

The distribution associated with Solution #4, "Expansion of Chelsea Station #488", will also require longer distribution feeders in East Boston to interconnect these circuits into the East Boston distribution system.

Solution #	Description (Substation Capacity Expansion)	Description (Transmission)	Additional Distribution Capacity	Lost load Reduction in 2023 (MW)	Low Voltage Elimination	Total 115-kV Cable Miles	Transmission Line Cost $M	Distribution Cost $M	Substation Cost $M	Total $M
1	New 115-KV/14-kV Substation at East Eagle	Two new 115-kV lines: • One Chelsea-E. Eagle • One Mystic-E. Eagle	75 MVA	357	Yes	4.74 miles	$47.3	$14.3	$54.4	$116.0
2	New 115-KV/14-kV Substation at East Eagle	Three new 115-kV lines: • Two Mystic-E. Eagle • One Mystic-Chelsea	75 MVA	357	Yes	9.46 miles	$96.0	$14.3	$50.5	$160.8
3	New 115-KV/14-kV Substation at East Eagle	Three new 115-kV lines: • Two Chelsea-E. Eagle • One Mystic-Chelsea	75 MVA	357	Yes	6.02 miles	$63.0	$14.3	$77.0	$154.3
4	Expansion of Chelsea Substation	One new 115-kV line • One Mystic-Chelsea	48 MVA	357	Yes	3.0 miles	$32.0	$57.9	$35.8	$125.7

Information Request EFSB-RR-17 (Tr. 2, at 284)

Please provide, if possible, a response from ISO-NE indicating its support for the East Eagle Street Substation as part of the solution to address reliability issues in the Mystic-Chelsea-Lynn area.

Response

Please see the attached letter from ISO-NE, Attachment EFSB-RR-17(1).

ISO new england

Brent Oberlin
Director, Transmission Planning

January 26, 2016

Robert Andrew
Director of System Planning
NSTAR Electric Company, d/b/a Eversource Energy
One NSTAR Way
Westwood, MA 02090

Subject: East Eagle Street Substation

Dear Mr. Andrew:

ISO New England (ISO-NE) is providing this letter regarding East Eagle Street Substation in response to Record Request RR-EFSB-17 (Tr. 2, at 284) in EFSB 14-4/D.P.U. 14-153/154 which asks: Please provide confirmation from ISO-NE with regard to its support for the East Eagle Street Substation as part of the solution to address reliability issues in the Mystic-Chelsea-Lynn area.

In October 2014, Eversource made a presentation[1] to the Planning Advisory Committee (PAC) that detailed concerns with the local load serving capability of the existing Chelsea Substation. One of the necessary components of the reliability projects to address the needs in the Greater Boston area is a new 115 kV line between Mystic and Chelsea. In order to address the local load serving needs at Chelsea, Eversource proposed the addition of a new substation at East Eagle Street to solve that need. Given that a new substation needed to be built, three alternatives were evaluated to determine how the new substation would be connected to the remainder of the system. Of the three alternatives the lowest cost estimate was the proposal to loop the proposed Mystic to Chelsea line into the new East Eagle Street Substation, resulting in two separate circuits, Mystic-East Eagle Street and East Eagle Street-Chelsea.

The East Eagle Street portion of the Mystic-East Eagle-Chelsea Reliability Project is not listed on the RSP Project List and represents a solution to a local rather than a regional need. Eversource will need to file and receive Proposed Plan Application (PPA) approval for the Mystic-East Eagle-Chelsea Reliability Project as required under Section I.3.9 of the ISO New England Tariff. With that said, the East Eagle Street Substation has been tested in the Greater Boston models used for solution development and is currently included in the ongoing studies for Greater Boston PPA approval. Accordingly, ISO New England has little concern at this time that any significant concerns would arise with PPA approval.

[1] https://smd.iso-ne.com/operations-services/ceii/pac/2014/a8_mystic_chelsea_line_east_eagle_needs_solutions.pdf

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Sincerely,

Brent K Oberlin

Brent Oberlin
Director, Transmission Planning

cc: Theodore Paradise, ISO New England

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Information Request EFSB-RR-18 (Tr. 2, at 344)

Please provide a list and a map of all businesses located across the Williams/Beacham Street area of the route. Include the city in which each business is located.

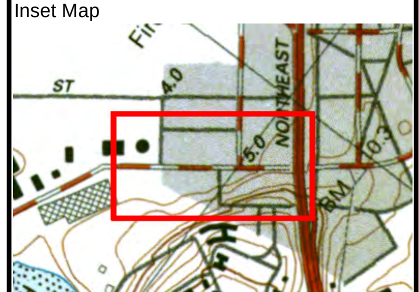
Response

Please see Attachment EFSB-RR-18(1) for a map of businesses located along the Williams/Beacham Street area of the route. Attachment EFSB-RR-18(2) provides a list of the businesses located along the Williams/Beacham Street area of the route. Please note that this list was developed by VHB through the completion of a field walkover on January 25, 2016 and includes the names and addresses of businesses as they were discernible from the public roadway only. Some of the business names presented here may not be completely accurate and there may be additional businesses along this section of route not shown here if they were not visible from the public roadway.

Path: \\nhbedata\gislib\NSTAR\EastBoston\EFSB\RR-EFSB-18(1).mxd Last Modified: 1/26/2016

Note: Businesses shown here were documented during a site walkover completed by VHB on 1/25/2016 along this section of roadway and contain names and addresses of businesses as they are discernible from the public roadway only. Note that some business names may not be completely accurate and there maybe additional businesses along this section of route not shown here.

Inset Map



- Business Locations
- East Eagle-Mystic Line (Preferred Route)
- Municipal Boundary

1 Inch = 100 Feet

0 50 100 200

Feet

Source: MassGIS VHB

Mystic-East Eagle-Chelsea Reliability Project

RR-EFSB-18(1)
Businesses located along Williams/Beacham Street
Area of Preferred Route

Page 1 of 5

EVERSOURCE ENERGY

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THIS DOCUMENT IS INTENDED FOR GENERAL PLANNING & INFORMATION PURPOSES ONLY. ALL MEASUREMENTS & LOCATIONS ARE APPROXIMATE

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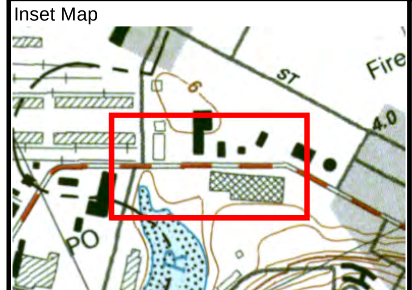

- Business Locations
- East Eagle-Mystic Line (Preferred Route)
- Municipal Boundary

1 Inch = 100 Feet
0 50 100 200
Feet

Source: MassGIS VHB

Mystic-East Eagle-Chelsea Reliability Project

RR-EFSB-18(1)
Businesses located along Williams/Beacham Street
Area of Preferred Route

Page 2 of 5

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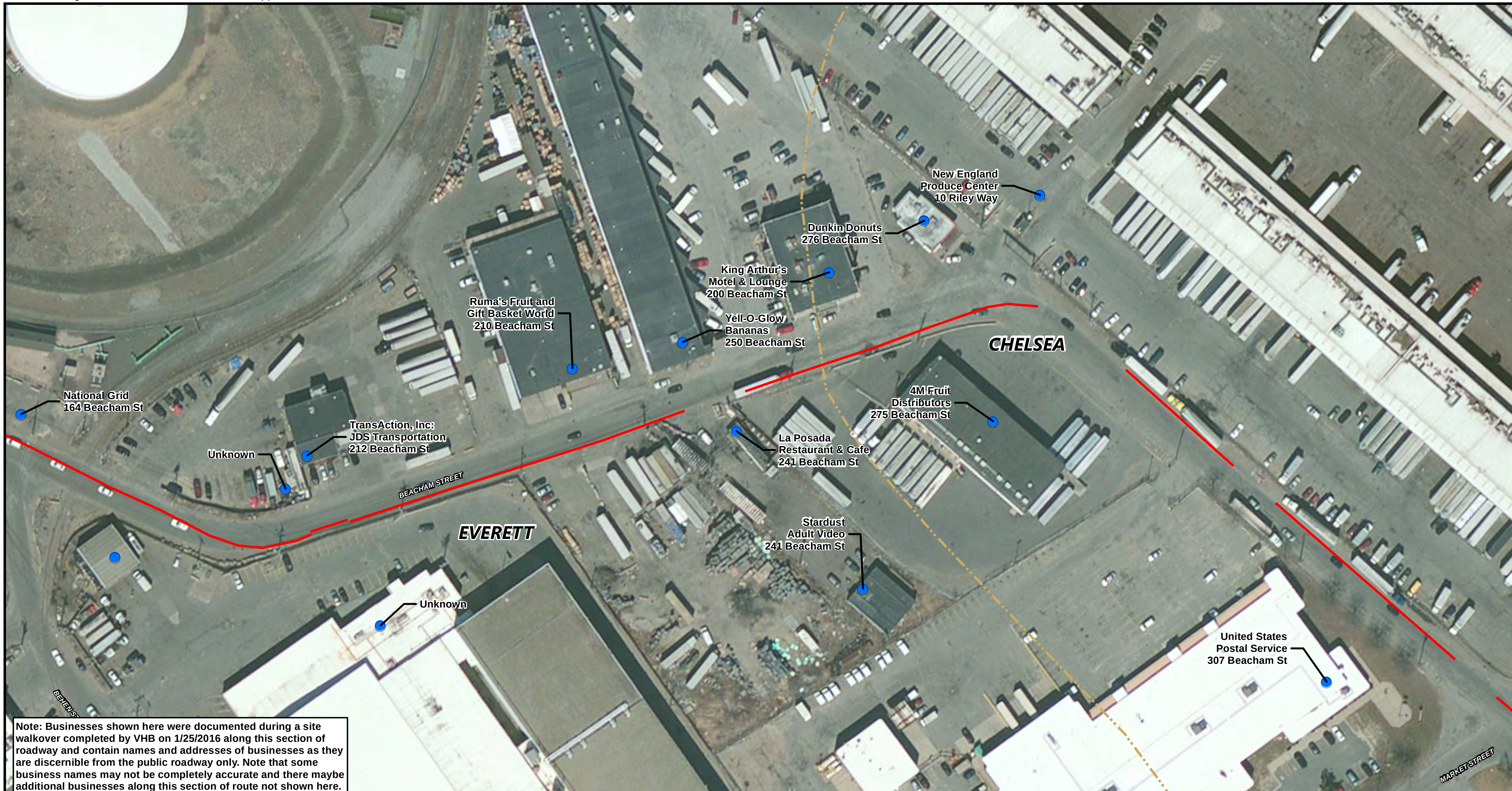

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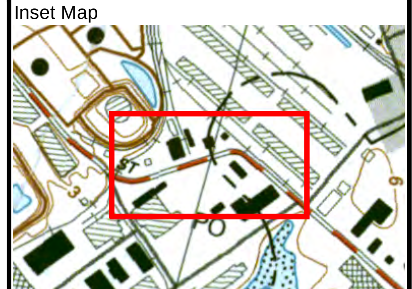

- Business Locations
- East Eagle-Mystic Line (Preferred Route)
- Municipal Boundary

1 Inch = 100 Feet

0 50 100 200

Feet

Source: MassGIS VHB

Mystic-East Eagle-Chelsea Reliability Project

RR-EFSB-18(1)
Businesses located along Williams/Beacham Street
Area of Preferred Route

Page 3 of 5

EVERSOURCE ENERGY

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Path: \\nhbedata\gislib\NSTAR\EastBoston\EFSB\RR-EFSB-18(1).mxd Last Modified: 1/26/2016

Note: Businesses shown here were documented during a site walkover completed by VHB on 1/25/2016 along this section of roadway and contain names and addresses of businesses as they are discernible from the public roadway only. Note that some business names may not be completely accurate and there maybe additional businesses along this section of route not shown here.

Inset Map

Business Locations
East Eagle-Mystic Line (Preferred Route)
Municipal Boundary

1 Inch = 100 Feet
0 50 100 200
Feet

Source: MassGIS VHB

Mystic-East Eagle-Chelsea Reliability Project

RR-EFSB-18(1)
Businesses located along Williams/Beacham Street
Area of Preferred Route

Page 4 of 5

EVERSOURCE ENERGY

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Path: \\nhbedata\gislib\NSTAR\EastBoston\EFSB\RR-EFSB-18(1).mxd Last Modified: 1/26/2016

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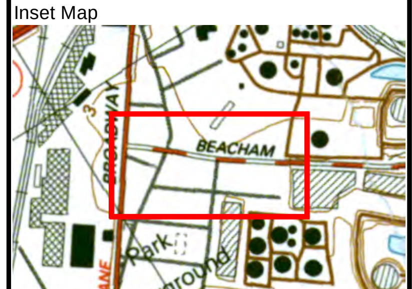

- Business Locations
- East Eagle-Mystic Line (Preferred Route)
- Municipal Boundary

1 Inch = 100 Feet

0 50 100 200

Feet

Source:
MassGIS
VHB

Mystic-East Eagle-Chelsea Reliability Project

RR-EFSB-18(1)
Businesses located along Williams/Beacham Street
Area of Preferred Route

Page 5 of 5

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Table RR-EFSB-18 (1)

List of Businesses Located Along Williams/Beacham Street Area of Preferred Route for Mystic to East Eagle

Street Address	Municipality	Business Name
9 Arlington St	Chelsea	Capic Child Development Center
15 Arlington St	Chelsea	Snipped Fresh Produce, Inc
25 Arlington St	Chelsea	Yell-O-Glow Corporation
38 Auburn St	Chelsea	Vacant
34 Auburn St	Chelsea	State Garden Facilities Department
36 Auburn St	Chelsea	Hub Food Corp
140 Williams St	Chelsea	Dick's Oil Co., Inc.
156 Williams St	Chelsea	Boston Cash and Carry
172 Williams St	Chelsea	Vacant
174 Williams St	Chelsea	Mystic Brewery
191 Williams St	Chelsea	Hardware Products Company, LLC
176 Williams St	Chelsea	Consolidated Service Corporation
215 Williams St	Chelsea	Baldor Boston
210 Williams St	Chelsea	DTZ (UGL Company)
201 Williams St	Chelsea	Steele Canvas Basket Corp.
222 Williams St	Chelsea	Eaton Cooper Interconnect
253 Williams St	Chelsea	State Garden
219 Williams St	Chelsea	DG's Trading Inc,
100 Justin Dr	Chelsea	Signature Breads
410 Beacham St	Chelsea	Irving Oil
410 Beacham St	Chelsea	Burke Oil
390 Beacham St	Chelsea	A&A Trading: Connect Prepaid LLC
350 Beacham St	Chelsea	New England Banana Co. & Fresh Produce
350 Beacham St	Chelsea	SP General Merchandise Wholesale
360 Beacham St	Chelsea	DiSilva Fruit (Arrowfarms Company)
380 Beacham St	Chelsea	Chelsea Public Works
390 Beacham St	Chelsea	Sunny Side Deli
357 Beacham St	Chelsea	People's United Bank
307 Beacham St	Chelsea	United States Postal Service
105 Market St	Chelsea	Fleet Fruit Wholesale
105 Market St	Chelsea	Jackpot Provision Co., Inc
115 Market St	Chelsea	One Specialty Foods, Inc
115 Market St	Chelsea	M. Cutone Mushroom Company, Inc.
115 Market St	Chelsea	New England Wine Grape
275 Beacham St	Chelsea	4M Fruit Distributors
10 Riley Way	Chelsea	New England Produce Center
200 Beacham St	Chelsea	King Arthur's Motel & Lounge
276 Beacham St	Chelsea	Dunkin Donuts
250 Beacham St	Everett	Yell-O-Glow Bananas
241 Beacham St	Everett	La Posada Restaurant & Cafe
241 Beacham St	Everett	Stardust Adult Video
164 Beacham St	Everett	National Grid
212 Beacham St	Everett	TransAction, Inc: JDS Transportation
210 Beacham St	Everett	Ruma's Fruit and Gift Basket World
168 Beacham St	Everett	Low Price Distribution Inc

(1) This list of businesses was developed through a field walkover along this section of roadway and contains names and addresses of businesses as they are discernible from the public roadway only.

Table RR-EFSB-18 (1)

List of Businesses Located Along Williams/Beacham Street Area of Preferred Route for Mystic to East Eagle

168 Beacham St	Everett	Metropolitan Signs Lettering
Behen Street	Everett	Whole Foods Kitchen
152 Beacham St	Everett	Vacant
152 Beacham St	Everett	Wine Grapes In New England
143 Beacham St	Everett	Distrigas Oil
52 Beacham St	Everett	Exxon Mobil
43 Beacham St	Everett	Sprague
30 Beacham St	Everett	Vacant
38 Courtland St	Everett	Paiva Marble & Granite

(1) This list of businesses was developed through a field walkover along this section of roadway and contains names and addresses of businesses as they are discernible from the public roadway only.

Information Request EFSB-RR-19 (Tr. 2, at 345)

Please provide the names and addresses of all individuals and businesses located in the Williams/Beacham Street area with which the Company has had contact other than the individuals and businesses listed in the Company's response to Information Request EFSB-G-8(R-1).

Response

The Company has had contact with the following individuals:

- Glenn Messinger, General Manager at Baldor Boston LLC located at 215 Williams Street, Chelsea
- Anne Jacobs of 219 Williams Street, Chelsea
- Roseanne Bongiovani, Deputy Director at the Chelsea Collaborative located at 300 Broadway, Chelsea
- John Lucero, General Manager of New England Produce Center, Chelsea

Information Request EFSB-RR-20 (Tr. 2, at 351)

Please provide the address or business location of each member of the Island End business group that attend the Everett Chamber of Commerce "Island End" business meeting that was held Wednesday, September 10, 2014, at the Distrigas Visitors Center, 101 Commercial Street, Everett, MA, as per the attendance sheet provided in Attachment EFSB-RS-8(1).

Response

The Company has requested this information from the Everett Chamber of Commerce and will update this response when/if the Company receives a response to the inquiry.