Thomas R. Teehan
Senior Counsel
Rhode Island

March 20, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4314 - February 2012 Retail Rates Filing
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to the Division's First Set of Data Requests in the above-captioned proceeding.

Thank you for your attention to this matter. If you have any questions, please feel free to contact me at (401) 784-7667.

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Steve Scialabba, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (hereinafter referred to as "National Grid" or the Company").

Certificate of Service

I hereby certify that a copy of the cover letter and / or any materials accompanying this certificate has been electronically transmitted, sent via U.S. mail or hand-delivered to the individuals listed below.

______________________________ March 20, 2012

Joanne M. Scanlon Date

National Grid – 2112 Annual Retail Rate Filing - Docket No. 4314
Service List Updated 2/17/12

Name/Address E-mail	Distribution	Phone/FAX
Thomas R. Teehan, Esq. National Grid. 280 Melrose St. Providence, RI 02907	Thomas.teehan@us.ngrid.com Joanne.scanlon@us.ngrid.com Jeanne.lloyd@us.ngrid.com	401-784-7667 401-784-4321
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File an original & 10 copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Lmassaro@puc.state.ri.us Cwilson@puc.state.ri.us Anault@puc.state.ri.us Nucci@puc.state.ri.us Dshah@puc.state.ri.us	401-780-2017 401-941-1691

Division 1-1

Request:

Please provide a copy of the settlement agreement containing the most recent version of the Integrated Facilities Agreement.

Response:

The Agreement can be found on pages 23 through 42 of the attached settlement agreement. Please refer to Attachment DIV 1-1.

Prepared by or under the supervision of: James L. Loschiavo

ALSTON&BIRD LLP

The Atlantic Building
950 F Street, NW
Washington, DC 20004-1404

202-239-3300
Fax: 202-239-3333

August 9, 2011

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: New England Power Company
Docket No. ER11-____-000
Filing to Implement Settlement Agreement
in Docket No. ER10-523

On July 8, 2011, in Docket Nos. ER10-523-000 and ER10-523-001, the Commission issued an order accepting without modification a proposed settlement agreement ("Settlement Agreement") submitted in those proceedings by New England Power Company, d/b/a National Grid ("NEP"), on March 31, 2011.[1] The July 8 Order directed NEP to file its Tariff, First Revised Volume No. 1, and Sixth Revised Service Agreement No. 20 between NEP and Massachusetts Electric Company and Nantucket Electric Company, in their entirety and as revised by the Settlement Agreement, in eTariff format within 30 days.[2]

Accordingly, NEP now files its revised Tariff and Service Agreement No. 20 in eTariff format for Commission acceptance effective January 1, 2010, as set forth in the Settlement Agreement.[3] The new designation for the Tariff is New England Power Company FERC Electric Tariff, Second Revised Volume No. 1. The new designation for Service Agreement No. 20 is Seventh Revised Service Agreement No. 20.

This compliance filing is being submitted one day out of time due to technical difficulties in uploading it to eTariff yesterday. NEP regrets any inconvenience this may have caused and requests leave to file the compliance filing one day out of time.

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1 *New England Power Co.*, 136 FERC ¶ 61,024 (2011) ("July 8 Order").
2 *Id.* at P 4.
3 Settlement Agreement at 7.

NEP has served this compliance filing on all parties in Docket Nos. ER10-523-000 and ER10-523-001. Please contact the undersigned with any questions.

Respectfully submitted,

_/s/ Sean A. Atkins

Sean A. Atkins
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Counsel for New England Power Company

FERC ELECTRIC TARIFF

SECOND REVISED VOLUME NUMBER 1

OF

NEW ENGLAND POWER COMPANY

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this
Tariff should be addressed to:

Director of Rates
New England Power Company
40 Sylvan Road
Waltham, Massachusetts 02451

NEW ENGLAND POWER COMPANY

Primary Service for Resale

TABLE OF CONTENTS

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers
General Terms and Conditions

Schedule I

A. Tariff.

Primary Service for resale and transmission service for Partial Requirements Customers are available only upon execution of a Service Agreement with the Company in the form set forth hereinafter.

Each such Service Agreement will incorporate these general terms and conditions (Schedule I), the Company's currently effective rate for primary service for resale (Schedule II), the terms and conditions applicable to the type of service to be rendered at said rate (Schedule III) and the specific interconnection arrangements with the Customer.

The Company will file each such Service Agreement with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder.

B. Amendments.

It is agreed that the Company shall have the right at any time to amend the General Terms and Conditions set forth in this Schedule I to the tariff, the Rate Provisions set forth in Schedule II to the tariff, the Terms and Conditions governing specified types of service set forth in Schedule III to the tariff, and the form of Service Agreement set forth in Schedule IV to the tariff, by serving an appropriate statement of such amendment upon the Customer and filing the same with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order duly issued by such agency.

C. Regulation.

This tariff, any Service Agreement executed pursuant thereto, and all the rights, obligations and performance of the parties to such service agreement, are subject to the Federal Power Act and to all other applicable state and federal laws and to all duly promulgated rules, regulations and orders of the Federal Power Commission and any other regulatory agency having jurisdiction in the premises.

The obligations of the parties are further subject to and conditioned upon their securing and retaining all rights-of-way, franchises, locations, permits and other rights and approvals necessary in order to permit service to be rendered as set forth in the Service Agreement, and each party agrees to use its best efforts to secure and retain all such rights-of-way, franchises, and other rights and approvals.

D. Availability of primary service for resale.

Primary service for resale is available only to electric utilities (including municipalities) engaged in the distribution of electricity to the public, whose electric requirements are supplied in whole or in part by the Company, either directly or over facilities for the use of which the Company has contractual arrangements.

Electricity so supplied is available for the Customer's own use and for resale to ultimate customers in the Customer's service area as it may exist from time to time, which area shall consist of one or more Districts to be specified in the Service Agreement. If the Customer's service area consists of two or more Districts, all provisions of the tariff shall apply to each District separately.

Primary service for resale is also available for sales for resale by the Customer (1) to electric utilities served by the Customer as of the date of and as specified in the Service Agreement; (2) to additional electric utilities which shall then be specified in the Service Agreement; and (3) under convenience contracts for the supply of electricity to borderline customers. With reference to sales under (2) above, the Customer shall give to the Company seven years' notice of intention to serve such utilities; the Customer shall furnish such information as the Company may reasonably request; and the parties shall establish mutually agreeable reasonable terms in connection therewith.

Service for Resale to Interruptible Customers under Schedule III-C is available only to utilities who are also taking service under Schedule III-A or III-B.

The Customer's sources of supply other than the Company shall be specified in the Service Agreement; and seven years' notice shall be given by the Customer to the Company of a change in Customer's source or sources, and such change shall be implemented pursuant to mutually agreed upon reasonable terms.

E. Availability of transmission service.

The types of transmission service available to the Partial Requirements Customer are specified in Schedule III to the tariff, and the Company will consider requests for additional types of transmission service; in each case to the extent that the Company deems its existing and planned transmission capacity can accommodate such additional service without additional new construction. In cases where new construction may be required to accommodate additional types of transmission service, the Company reserves the right in its discretion either to refuse to undertake such further service, or to request financial assurance that any additional transmission investments and costs will be adequately provided for.

F. Character of primary electric service.

Electricity will be supplied in the form of three-phase, sixty-hertz alternating current at the nominal voltage or voltages specified in the Service Agreement.

The Company will maintain and operate its interconnected generating and transmission system, together with any delivery facilities required for service to the Customer, in accordance with good utility practice. The Company will use due diligence in maintaining an aggregate capacity of such facilities sufficiently in excess of current Demand to allow for the Customer's expected load growth, and the Customer will keep the Company informed as to expected trends of its load growth.

The Company shall not be liable in damages to the Customer for any failure to supply electricity nor to provide transmission service in accordance with the preceding paragraphs if prevented from doing so by reason of storm, flood, earthquake, fire, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or other public authority, or any cause beyond its reasonable control; and shall not be liable in damages to the Customer for any reduction in voltage or interruption of service resulting from the operation in accordance with good utility practice of an emergency load-reduction program; but in any such case the Company will exercise due diligence to remove the cause of any disability at the earliest practicable time. The Company and the Customer shall have the obligation to operate in accordance with good utility practice, including an emergency load reduction program, and upon request, to consult with each other in regards thereto.

G. Delivery and ownership of facilities.

1. All deliveries will be made a single delivery point in each District (which may also be used to serve other customers of the Company or affiliated companies of the New England Electric System), except where District load can be more feasibly served by multiple delivery points. The Service Agreement shall set forth with respect to each District of the

Customer's system the point or points of delivery, the delivery voltage or voltages and the ownership of transformation and metering equipment.

2. Deliveries at each delivery point will be made at a single voltage except as otherwise provided in the Service Agreement.

3. All lines, apparatus and other equipment up to the point of delivery shall be supplied, maintained and operated by the Company or affiliated companies of the New England Electric System, and all such equipment beyond such point of delivery shall be supplied, maintained and operated by the Customer. The Customer shall, however, supply free of cost a suitable place for the installation of the Company's metering equipment and any of the Company's lines, or other equipment which it is proper to locate on the Customer's property, and the Company shall have access to the Customer's property for all reasonable purposes in connection therewith.

4. All the Customer's lines, apparatus and equipment (and the maintenance, operation and adjustment of the same) which are connected to the facilities of the Company, and the maintenance, operation and adjustment of which may adversely affect the operation of the Company's facilities, shall be subject to the reasonable inspection and approval of the Company.

5. The Customer assumes all responsibility for electricity beyond the point of delivery, and the Company shall not be liable for damage to the person or property of the Customer or of its employees or of any other persons resulting from the use of electricity beyond the point of delivery.

Variations from the provisions of paragraphs 1 through 5 above will be permitted, in the discretion of the Company, if and to the extent that equitable adjustments are provided for and set forth in the Service Agreement.

H. Metering.

The Company reserves the right to determine the metering installations and will supply the metering equipment for determining the quantity and conditions of supply of electricity delivered hereunder. Any exceptions to this provision shall be reflected in the Service Agreement.

If at any time such equipment shall be found to be inaccurate by more than 2% up or down, the owner shall make it accurate and the charges and meter readings for the period of inaccuracy, so far as the same can reasonably be ascertained, shall be adjusted. However, no adjustment prior to the beginning of the next preceding month shall be made except by mutual agreement.

In addition to regular routine tests, the owner shall have any such meter tested at any time upon written request of the other party, and if such meter prove accurate within 2% up or down the expense of the test shall be borne by the party requesting the test.

I. Transmission losses.

Unless otherwise specified in the tariff, all losses incurred in providing transmission service hereunder shall be for the account of the Customer, and delivery of the aggregate quantity of electricity received for transmission, less such losses, shall constitute full performance by the Company. When segregation of energy flows is required to determine such losses, the Company will calculate the same in accordance with good engineering practice.

J. Billing and payment.

Bills for each month shall be rendered during the first part of the next succeeding month and shall be due when rendered.

As used herein the term “month” shall refer to the period between two meter readings each of which shall have been taken within two days of the end of successive calendar months.

When all or part of any bill shall remain unpaid for more than thirty (30) days after the rendering thereof by the Company, interest at the rate of 1 ½% per month shall accrue to the Company from and after the rendering of said bill and be payable to the Company on either: (1) such unpaid amount or (2) in the event the amount of the bill is disputed, the amount finally determined to be due and payable.

Notwithstanding the foregoing, no late payment penalty shall be imposed upon any customer where payment is made within forty-fine (45) days of the rendering of the bill by the Company provided that each of the following conditions are met: 1) the average prior calendar year’s monthly billing to such customer was less than $45,000; and 2) payment of such bill within thirty (30) days by such customer would cause undue hardship because of the fact that one or more part-time employees or officials are essential to the processing of payment by such customer. A letter from an appropriate official of a customer certifying that one or more part-time employees are essential to the processing of payment shall constitute satisfactory evidence that condition 2 herein has been met.

In addition, no late payment penalty shall be imposed upon any customer electing to make installment payments with respect to any bill so long as the weighted average payment date, based on the amount of each payment, is no later than 30 days after the date of the rendering of the bill.

K. Remedies.

If any bill remains unpaid for more than sixty days, except amounts in dispute, the Company may apply to the regulatory agency having jurisdiction to suspend delivery of electricity until full payment has been made of all amounts due.

If either party shall have defaulted in any of its obligations and such default shall have continued for and not been remedied within sixty days after receipt of a written notice from the other party specifying the nature of such default in reasonable detail, the other party may by written notice terminate the Service Agreement at the end of the next succeeding calendar month. No delay by either party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which other party is legally entitled.

L. Hours of Labor.

The Company agrees to comply with the provisions of the General Laws of Massachusetts, Chapter 149, Section 34, as amended, with reference to the hours of laborers, workmen or mechanics in its employ, so far as the same may be applicable to work under this tariff.

M. Notices.

Notices by the Company or the Customer shall be in writing, mailed or delivered to the respective addresses set forth in the Service Agreement. Either party may change its address by written notice to the other.

N. Term.

Once initiated, service under this tariff shall continue until terminated by either party giving to the other at least seven years' written notice of termination directed to the end of a calendar month.

A Customer that seeks to terminate service without providing the notice required under this tariff and its service agreement and that has not otherwise agreed to a settlement of its early termination costs may exercise an option to terminate service under this tariff early by giving the

Company thirty days' written notice directed to the end of a calendar month and paying the Contract Termination Charge applicable under Schedule II-C of this tariff. The Contract Termination Charge shall be payable in equal monthly installments of principal and interest, the first payment to be made within 30 days after the date of termination of service ("Early Termination Date"), over the remaining term of the Customer's notice period (or such shorter term, or in a single payment, as agreed by the Company and the Customer). The Customer's payments shall include carrying charges on the unpaid amount of the Contract Termination Charge at the interest rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. 35.19a) effective on the Early Termination Date and compounded monthly. The Company reserves the right to require the Customer to provide security in a form appropriate to the Company and consistent with commercial practices to protect the Company against the risk of non-payment. This paragraph shall not apply to Customers that have entered into settlement agreements with the Company allowing early termination of service under this tariff and establishing the recovery of contract termination charges. The Company at its discretion may waive the thirty days' notice provision under this paragraph.

O. <u>Successors and assigns.</u>

The executed service agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties.

NEW ENGLAND POWER COMPANY

Schedule II-A

THIS SECTION INTENTIONALLY LEFT BLANK

NEW ENGLAND POWER COMPANY

Schedule II-B

NEW ENGLAND POWER COMPANY
Primary Service for Resale
Rate W-95(N)

Demand Charge:	$17.17 per month for each kilowatt of Demand.
Energy Charge:	21.83 mills ($0.02183) for each kilowatt-hour of electricity delivered, except for kilowatt-hours of electricity delivered under Service for Resale to Interruptible Customers, Schedule III-C.
Interruptible Service: Charge	For each kilowatt-hour delivered in any hour pursuant to Schedule III-C, the amount specified for that hour by the Company pursuant to Paragraph C of Schedule III-C
Fuel and Purchased Economic Power Adjustment Clause:	For any month for which the Cost of Fuel is greater or less than 14.0000 mills per kilowatt-hour, the Energy Charge shall be increased or decreased respectively by the applicable fuel adjustment rate per kilowatt-hour delivered, which rate shall be equal to the difference of:

$$\frac{Fm}{Sm} - \frac{Fb}{Sb}$$

Where F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and "S" is the kilowatt-hour sales in the base and current periods, all as defined in Section 35.14 of the Regulations under the Federal Power Act as provided in Order No. 352 issued December 7, 1983 in Docket No. RM83-62-000. F shall also include expenses associated with purchases of electricity from alternate energy suppliers, provided however that payments from such suppliers due to their failure to perform or pursuant to contractual security provisions shall be credited to F above. F shall be credited with the revenues from sales for resale to interruptible customers pursuant to Schedule III-C and such sales shall be excluded from S.

As a signatory to the NEPOOL Agreement, dated as of September 1, 1971, as amended, the Company's reserve capacity criteria is determined as a part of the NEPOOL reserve requirement. This type of interconnected pool operation avoids the need for member companies to individually determine reserve capacity criteria, while preserving individual company integrity through the basic NEPOOL Agreement. Each member utility's commitment to the Pool's requirements is assured by a monthly assessment of each members "Capability Responsibility", as defined in the NEPOOL Agreement. See also the NEPOOL Agreement, FERC Rate Schedule No. 210. In determining whether a purchase is a reliability purchase, the Company will use its then-applicable NEPOOL reserve requirement, regardless of whether the selling utility is a member of NEPOOL. In the event that a short term operating reserve purchase is made by NEPOOL and an assessable share is billed to NEP, NEP will include in this clause only the cost of fuel associated with such purchase. Part of the costs in evaluating the interchange with NEPEX (the NEPOOL dispatching agency) may initially be estimated. All energy savings shares that are created in the NEPEX dispatch are reflected in fuel costs. The value of the estimated costs will be combined with the value of the actual costs for the billing month to determine the monthly fuel clause factor. Any difference between the actual and estimated data for a billing month will be reflected in cost data utilized in the calculation for the succeeding month.

Notwithstanding the above, whenever the foregoing determination would be affected by energy produced from generating units under construction as they undergo operational tests prior to their in service dates, the components of F shall be adjusted so that its value is the same as it would have been if such test energy were not available. Such adjustment to F in the formula shall also recognize that current wholesale customers have paid a part of the cost of generating units under construction through demand charges reflecting CWIP in rate base; therefore, a credit to F shall be applied equal to the differential between the cost of test energy and the displaced cost of fuel in the ratio that demand contributions for such units bear to the carrying cost of such units.

In addition to the foregoing, F shall also include fifty percent (50%) of all natural gas transportation demand charges incurred for the period beginning November 1, 1991 and ending on the sooner to occur of January 1, 1996 or the conclusion of the construction period for the Manchester Street Station repowering project, provided, however, that revenues received from third parties related to their use of NEP's pipeline capacity during the foregoing period shall be credited to F above. Thereafter, all natural gas transportation demand charges incurred shall be included in F above.

Once each calendar year, NEP shall reconcile the total incremental fuel costs of all short-term unit sales transactions, and sales pursuant to Schedule III-C, to fuel revenue from these transactions. If the total incremental fuel cost exceeds the fuel revenue, F shall be credited with the differential. The reconciliations shall be done in accordance with the procedures set forth in Dockets 92-372-000 et al. (unit power contracts) and Docket No. 94-1056-000 (Schedule III-C sales).

In accordance with a Surcharge Compliance Filing Settlement Agreement filed in Docket Nos. ER88-630-000, et al., a monthly charge for fuel expense underrecovery will be assessed all Customers except Massachusetts Electric Company, as shown at Appendix C to that Settlement Agreement. The foregoing charge will become effective as approved by the Commission and will continue thereafter for a period of ten (10) years, provided that if any of these Customers terminates service from NEP prior to the conclusion of the amortization period, that Customer shall pay its remaining unamortized fuel expense upon the date it terminates service. The monthly charge will be: Narragansett Electric - $48,889, Granite State - $6,499, Groveland - $225, Merrimac - $196, Littleton - $535, Norwood - $3,128, N.H. Elec. Coop - $66, GMP - $52, and Ft. Devens - $540.

In accordance with the settlement of Docket No. FA91-53-000, F shall also include the 1.5% NEPEX differential billed to NEP by Central Maine Power for the use of low sulphur oil in the Wyman Units 1, 2, and 3 when Wyman 4 is operating.

Standard Delivery Point: For purposes of this Tariff, the “Standard Delivery Point” shall be considered to be that point on the integrated generating and transmission system of the Company that first follows one transformation from the power supply system or, by agreement of the parties, a point in close proximity thereto.

Metering Adjustments: Where delivery is metered at the Company’s supply line voltage, in no case less than 69,000 volts, thereby saving the Company transformer losses then, before determining the number of kilowatts and kilowatt-hours to be billed under the preceding provisions, there shall be deducted from the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one percent (1.0%) of such registrations. Where delivery is metered at the sub-transmission voltage, or at the low side terminals of the transformation from the sub-transmission to the distribution of the customer, and not at the low side terminals of the transformation from the Company's supply line, there shall be added to the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one and one half percent (1.5%) of such registrations.

Transformer Ownership Credit:

If delivery is made at the Company's supply line voltage, not less than 69,000 volts, and the Company is saved the cost of installing any transformer and associated equipment there will be allowed a credit of thirty cents ($0.30) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. In accordance with a Settlement Agreement in Docket Nos. ER91-565-000, et al., the credit applicable to the Town of Norwood will be twenty-one cents ($0.21) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. The foregoing credits, as applicable, shall be computed after the applicable Metering Adjustments.

Credit for EPRI Contributions:

A credit of six cents ($0.06) per kilowatt of the demand component will be allowed to all customers served under this schedule with the exception of the Company's affiliated customers (Massachusetts Electric Company, Narragansett Electric Company and Granite State Electric Company) in order to reflect the Company's commitment to research support of the Electric Power Research Institute (EPRI) unless a customer notifies the Company in writing that it desires to contribute through the Company's commitment, in which event this credit shall not apply to such Customer. In accordance with a Settlement Agreement in Docket Nos. ER91-565, et al., the credit applicable to the Town of Norwood will be nine cents ($0.09) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. These credits shall be computed after the application of any applicable Metering Adjustments and at the point of delivery which enters into the computation of the Customer's Demand for the month in question.

Norwood Yankee: Surcharge:	In accordance with the terms of the W-12 Settlement Amendment dated December 17, 1992 in Docket No. ER90-525 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with that settlement.
Norwood Seabrook 1 Amortization Surcharge:	In accordance with the terms of the W-95(N) Settlement dated June 30, 1995 in Docket No. ER95-267 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with section 2.2(b) of that settlement.

The Company reserves the right to amend the foregoing rate in the manner set forth in its General Terms and Conditions governing primary service for resale in Schedule I.

Effective Date: July 12, 1995

NEW ENGLAND POWER COMPANY

Primary Service for Resale

DETERMINATION OF CONTRACT TERMINATION CHARGE
UNDER EARLY TERMINATION PROVISION

A. Applicability

The terms and conditions of this Schedule II-C are applicable to any eligible all-requirements wholesale customer ("Customer") of New England Power Company ("Company") under this tariff which elects the early termination option under Schedule I, Section N of this tariff.

B. Determination of Contract Termination Charge

If a Customer exercises the early termination option under Schedule I, Section N, paragraph 2, of this tariff, the Customer shall pay the Company a Contract Termination Charge ("CTC") as determined under this schedule. The CTC shall be determined as follows:

$$CTC = (R - M) \times L$$

where:

R	=	the Customer's Annual Average Revenue, as determined in Section 1 below;
M	=	the Estimated Market Value of the Customer's released capacity and associated energy, as determined under Section 2 below;
L	=	the Length of Obligation in years, as determined under Section 3 below;

Payment of the CTC by the Customer shall be in accordance with Schedule I, Section N, paragraph 2, of this tariff.

The CRC shall be determined on a net present value basis, with the difference between R and M discounted to the Early Termination Date as defined in Section 3 below. The discount rate used shall equal the rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. § 35.19a) effective on the Early Termination Date.

In no event shall the CTC exceed the amount determined under section 4 below.

1. <u>R – Average Annual Revenue</u>

The Customer's Annual Average Revenue shall equal the Total Revenue minus the Transmission Revenue.

a. *<u>Total Revenue</u>* shall equal the annual average of revenues received by the Company from the Customer over three years under the presently effective rates as shown on Schedule II-A and Schedule II-B of this tariff. The three-year period shall be the 36 months immediately prior to the Early Termination Date as specified by the Customer under the second paragraph of Schedule I, Section N of this tariff. In the event that the rates paid by the Customer under Schedule II-A or Schedule II-B of this tariff have changed during the three-year period, Total Revenue shall be determined using the Customer's revenue for the 12 months immediately prior to the Early Termination Date. The Company at its discretion may use estimates of the Customer's billing units for determining Total Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date. The calculation of Total Revenue shall include credits pursuant to Schedule III-D of this tariff as well as all credits and surcharges applicable to the Customer under the Customer's Service Agreement with the Company under this tariff, with the exception of credits associated with Integrated Facilities arrangements under Schedule III-B of this tariff and any credits associated with the Company's reimbursement of the Customer's payments to third parties for transmission service.

b. *<u>Transmission Revenue</u>* shall equal the sum of: (i) the annual average of revenues the Company credited to the Customer with respect to payments made by the Customer to third parties for transmission service pursuant to any applicable provision of the service agreement between the Company and the Customer; or (ii) if the service agreement does not provide for such credits, the annual average of revenues the Company would have received from the Customer using the presently effective rates under the Company's Open Access Transmission Tariff, FERC Electric Tariff Original Volume No. 9 ("Tariff No. 9"); and (iii) the annual average of payments made by the Company to the New England Power Pool ("NEPOOL") for transmission service on the Customer's behalf under NEPOOL's Open Access Transmission Tariff, all as determined during the period over which the Total Revenue is determined. The Company at its discretion may use estimates of the Customer's billing units for determining Transmission Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date.

2. <u>M – Estimated Market Value</u>

The Estimated Market Value shall equal the annual average of the Market Price Estimate for each year of the Length of Obligation (as determined pursuant to Section 3 below) multiplied by the Customer's Released Load.

a. *Market Price Estimate* shall equal the per kilowatt-hour amount set forth in the Table below, as in effect on the Early Termination Date, as applicable to each year during the Length of Obligation. The Market Price Estimate shall include both a capacity-related and energy-related component.

Year	Capacity (¢/kWh)	Energy (¢/kWh)	Total (¢/kWh)
1998	1.10	2.71	3.81
1999	1.22	2.64	3.86
2000	1.22	2.66	3.88
2001	1.25	2.61	3.86
2002	1.31	2.63	3.94
2003	1.34	2.71	4.05
2004	1.40	2.72	4.12
2005	1.44	2.77	4.21
2006	1.47	2.86	4.33
2007	1.53	2.95	4.48
2008 forward		prices for 2007 escalated at 2% annually	

b. *Released Load* shall equal the annual average of the Customer's kilowatt-hour purchases from the Company for the period over which Total Revenue is determined. The Company at its discretion may use estimates of the Customer's kilowatt-hour purchases for determining Released Load, such estimates to be reconciled to actual purchases within six months after the Early Termination Date.

3. <u>L – Length of Obligation</u>

The Length of Obligation shall equal the time period between the Early Termination Date and the Regular Termination Date.

a. *Early Termination Date* shall be as determined under Schedule I, Section N, paragraph 2 of this tariff

b. *Regular Termination Date* shall be the date at which the Company or the Customer could have unilaterally terminated service under Schedule I, Section N, paragraph 1 of this tariff and any applicable provisions of the Customer's Service Agreement with the Company under this tariff.

4. <u>Maximum Contract Termination Charge</u>

In no event shall the difference between R and M (as determined in Sections 1 and 2 above) exceed the Customer's annual contribution to the Company's fixed power supply costs under this tariff. The Customer's annual contribution to the company's fixed power supply costs shall equal its Total Revenue minus Transmission Revenue minus the Company's Average Fuel Costs. Average Fuel Costs shall equal the annual average of revenues the Company recovered for its Cost of Fuel as defined in Schedule II-A of this tariff multiplied by the Customer's monthly kilowatt-hour purchases during the period over which Total Revenue is determined in Section 1 above.

NEW ENGLAND POWER COMPANY

Schedule III-A

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NEW ENGLAND POWER COMPANY

Primary Service for Resale

TERMS AND CONDITIONS

governing

ALL-REQUIREMENTS SERVICE — INTEGRATED FACILITIES

Schedule III-B

A. Applicability

The terms and conditions set forth herein shall apply when the Service Agreement is between the Company and a Customer which is affiliated with the New England Power Company, and specifies All-Requirements Service — Integrated Facilities.

B. Integrated facilities: Obligations of the parties.

Recognizing that the generation and transmission facilities owned by the Company and the Customer are physically interconnected and can be operated to achieve maximum economy through integrated operation, the Customer and the Company agree as follows:

1. The Customer will operate and maintain its generating and transmission facilities in accordance with standards fixed from time to time by the Company, and will make available to the Company the full capacity of such facilities to meet the load of the integrated generating and transmission system (consisting of the generating and transmission facilities owned by the Company and affiliated companies of the New England Power Company). The Company and the Customer may agree to exclude from the facilities made available as aforesaid any facilities deemed not to be necessary or feasible for integration, and such excluded facilities shall not be considered part of the integrated generating and transmission system as defined above.

2. The generating and transmission facilities of the Customer made available to the Company under paragraph 1 shall be subject to dispatch by the Company to meet the load of the integrated generating and transmission system, and the output of the Customer's generating units so dispatched shall be deemed to be for the account of the Company. The Customer will conform to maintenance schedules fixed by the Company to ensure maximum availability of capacity.

3. The Company and the customers whose facilities constitute a part of the integrated generating and transmission system will plan jointly for the future requirements of such system. The Customer agrees to make additions to and retirements of its generating and transmission facilities in accordance with schedules fixed from time to time by the Company.

4. In consideration of the foregoing, the Company assumes responsibility for the supply of the electrical requirements of the Customer from the integrated generating and transmission system, including transmission losses over such system, and agrees to credit the Customer for the use of its generating and transmission facilities, in accordance with the following provisions:

    a. The Company agrees to sell and the Customer agrees to buy, at the Company's effective rate for primary service for resale, the Customer's entire requirements of electricity for its own use and for resale within the Districts described in the Service Agreement, with the following exceptions: (1) electricity purchased by the Customer from commercial and industrial establishments located within any District of the Customer's service area and specified in the Service Agreement, (2) electricity purchased by the Customer under convenience contracts for the supply of electricity to borderline customers, and (3) such other exceptions as may be mutually agreed upon between the parties and set forth in the Service Agreement.

    b. For Customer-owned Transmission Plant, the Company will credit each monthly bill rendered to the Customer using the calculation shown below based on the previous month's cost data from Customer's official books and records. Capitalized terms used in this calculation will have the following definitions:

        1. Gross Transmission Plant Allocation Factor shall equal the ratio of Customer's Total Investment in Transmission Plant to Total Plant in Service, excluding General Plant.

        2. PTF Allocation Factor shall equal the ratio of PTF Transmission Plant to Transmission Plant.

        3. PTF-RSP Allocation Factor shall equal the ratio of PTF-RSP Transmission Plant to Transmission Plant.

        4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct electric wages and salaries from Customer to Customer's total electric direct wages and salaries and excluding electric administrative and general wages and salaries.

5. Administrative and General Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 920-935, less Post Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, plus the FERC-accepted Post Employment Benefit Other than Pensions identified in each Customer's Service Agreement or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

6. Amortization of Investment Tax Credits shall equal Customer's electric credits as recorded in FERC Account No. 411.4.

7. Amortization of Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account No. 428.1.

8. Depreciation Expense for Transmission Plant shall equal Customer's electric transmission plant related depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement.

9. General Plant shall equal Customer's electric gross general plant balance as recorded in FERC Account Nos. 389-399.

10. General Plant Depreciation Expense shall equal Customer's electric general plant related depreciation expenses as recorded in FERC Account No. 403.

11. General Plant Depreciation Reserve shall equal Customer's electric general plant depreciation reserve balance as recorded in FERC Account No. 108.

12. Municipal Tax Expenses shall equal Customer's electric transmission-related municipal tax expense as recorded in FERC Account No. 408.1.

13. Payroll Taxes shall equal those electric payroll tax expenses as recorded in Customer's FERC Account Nos. 408.1.

14. Land Held for Future Use shall equal the Customer's electric transmission-related balance for Land in FERC Account No. 105.

15. Prepayments shall equal Customer's electric prepayment balance as recorded in FERC Account No. 165.

16. PTF-RSP Transmission Plant shall equal any PTF Transmission

Plant as defined below and approved as part of the ISO-NE Regional System Plan.

17. PTF Transmission Plant shall equal electric transmission plant as defined in Section II.49 of the ISO-NE OATT and determined in accordance with Appendix A of Attachment F Implementation Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

18. Total Accumulated Deferred Income Taxes shall equal the net of Customer's electric deferred tax balance as recorded in FERC Account Nos. 281-283 and Customer's electric deferred tax balance as recorded in FERC Account No. 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities.

19. Total Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account 189.

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

21. Total Transmission Depreciation Reserve shall equal Customer's electric transmission plant related depreciation reserve balance as recorded in FERC Account 108.

22. Transmission Operation and Maintenance Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 560-564 and 566-573 less any expenses recorded in FERC Account 561.4.

23. Transmission Plant shall equal Customer's electric gross plant balance as recorded in FERC Account Nos. 350-359.

24. Transmission Plant Materials and Supplies shall equal Customer's electric materials and supplies balance as recorded in FERC Account No. 154

25. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided which is not specifically identified under any other section contained herein.

In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

Calculation of Transmission Revenue Requirements

The monthly Transmission Revenue Requirement shall equal the sum of Customer’s (A) Return and Associated Income Taxes (including the Incremental Returns for PTF-RSP and PTF Investment), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Distribution, Credit, (J) Transmission Related Taxes and Fees Charge, (K) Billing Adjustments, and (L) Annual True-Up Adjustment. The Incremental Return and Associated Income Taxes for PTF-RSP and PTF Investments shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of each of the Transmission Investment Base (PTF-RSP, PTF and Non-PTF, respectively) and the Cost of Capital Rates applicable to each.

1. Transmission Investment Base

(a) Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(i) PTF-RSP Investment Base will be the monthly balances of PTF-RSP Transmission Plant, less the sum of (d)

Transmission Related Depreciation Reserve and (e) Transmission Related Accumulated Deferred Income Taxes, multiplied by the PTF-RSP Allocation Factor.

(ii) PTF Transmission Investment Base will be the monthly balances of PTF Transmission Plant, less PTF-RSP Investment Base, plus the product of: PTF Allocation Factor multiplied by the sum of the [(b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Income Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital].

(iii) Non-PTF Transmission Investment Base shall equal Total Transmission Investment Base less PTF-RSP Investment Base less PTF Investment Base.

(b) Transmission Related General Plant shall equal Customer's balance of investment in electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Land Held for Future Use shall equal Customer's balance of electric Transmission-related Land Held for Future Use.

(d) Transmission Related Construction Work In Progress shall equal the portion of Customer's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal Customer's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal Customer's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Gross Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal

Customer's electric balance of Total Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal Customer's electric balance of prepayments multiplied by the Gross Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal Customer's electric balance of Transmission Plant Materials and Supplies, multiplied by the Gross Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Customer's Transmission Operation and Maintenance Expense (less FERC Account 565: Transmission of Electricity by Others) and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will incorporate Customer's imputed capital structure, Customer's actual cost of long-term debt and preferred equity, and approved ROEs for Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively), plus Federal Income Tax.

(a) The Weighted Costs of Capital will be calculated for each of the Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively) based upon the imputed capital structure for Customer in place in accordance with Rhode Island Docket Nos. 2930 and 3617 and will equal the sum of (i), (ii), and each ROE applied in item (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45%.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Customer's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5%.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs applicable to the corresponding investments below and the Customer's imputed common equity capitalization ratio of 50%.:

12.64% - Post-2003 to pre-2009 PTF transmission plant investment included in the Regional System Plan approved by ISO-NE.

11.64% - The remaining PTF transmission plan investment.

11.14% - The remaining transmission plant investment.

As per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679. To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

(b) Federal Income Tax applied shall equal

$$(PS + ROE) \quad X \quad \frac{\text{Federal Income Tax Rate}}{(1- \text{Federal Income Tax Rate})}$$

where PS is the Preferred Stock Component and ROE is the return on equity component, each as determined in Sections 2.(a)(ii) and for the applied ROEs set forth in 2.(a)(iii) above.

B. Transmission Depreciation Expense shall equal Customer's electric Depreciation Expense for Transmission Plant, plus an allocation of electric General Plant Depreciation Expense calculated by multiplying electric General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Customer's electric Amortization of Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Customer's electric Amortization of Investment Tax Credits multiplied by the Gross Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal Customer's transmission-related electric municipal tax expense.

F. Transmission Related Payroll Tax Expense shall equal Customer's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Customer's total electric Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of Customer's electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

I. Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this section, including, but not limited to, expenses incurred by the Customer related to third party independent audits conducted at the request of any governmental authority, and any other fee or assessment which is not specifically identified under any other section contained herein. Such costs will be separately identified and included in item H — Administrative and General Expense, above.

K. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.

L. Annual True-Up Adjustment

1. NEP shall submit an annual informational filing with the FERC with copies to state commissions and attorneys general in the state of any affected Customer reconciling monthly billings to Customer under this formula to data supplied from Customer's Quarterly FERC Form 1 (the "Annual True- up"). The Annual True-up will be completed no later than (3) months after Customer issues its final 4th Quarter FERC Form 1 for the calendar year which the Annual True-up relates (the "Service Year"). The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form l's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all

balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

2. The difference, if any, between the monthly actual costs invoiced to Customer during the Service Year and the annual revenue requirement based on actual FERC Form 1 data shall be reflected as an adjustment to the monthly revenue requirement calculation for the month following the month in which the Annual True-Up report is issued (the "Annual True-up Adjustment").

3. If the recalculation of costs for the Service Year using FERC Form 1 data exceeds the monthly billed amounts for the Service Year, the Annual True-up Adjustment will be an additional credit to Customer. If the monthly billed amounts for the Service Year exceed the recalculation of costs using FERC Form 1, the Annual True-up Adjustment will be a reduction to the credit to Customer. The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the Commission's regulations 18 C.F.R §35.19a.

4. Any changes to the data inputs, including but not limited to revisions to Customer's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-up, or as a result of the procedures set forth herein not otherwise captured as part of ongoing Billing Adjustments, shall be incorporated into the formula rate and the charges produced by the formula rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual True-up for the next effective rate period.

5. In any proceeding before the FERC concerning the Annual True-up, the Company shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

M. Five-Year Forecast

The Company's annual informational filing will also provide a report containing a five year forecast of anticipated transmission capital expenditures by the Company and its Customers taking service under this Tariff that will, upon completion of projects, be included in transmission rates. The forecast will also include the estimated retail rate impacts for each of the Company's respective Customers under this Schedule III-B.

N. Audit Provisions

1. There will be an "Audit Period" that will extend from the date the informational filing is filed with FERC through December 31 of the year following the Service Year. At any time during the Audit Period, a Customer shall have the right to request an audit or conduct an inspection of the actual data used in the Annual True-Up and any and all transmission charges or credits billed by Company during the Service Year. Subject to the limitation that the Attorneys General of Massachusetts and Rhode Island do not make or receive transmission payments or refunds, they shall have the same procedural rights under this Section as a Customer. Company shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel as prescribed by FERC. Company is not obligated to disclose privileged information or information protected by the attorney work product doctrine. Company shall exercise all commercially reasonable efforts to provide Customer, within 10 business days, such additional information as Customer may reasonably request. To the extent requested, Company shall meet with any Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up or any other information related to Customer billing under this Tariff during the Service Year. During the Audit Period any Customer may request that Company adjust the Annual True-up Adjustment and/or Customer bills rendered during the Service Year. Any adjustment that Company agrees to make may be reflected in the next month following such adjustment. Upon request of any Customer during the Audit Period, Company shall engage a third party independent auditor (the "Auditing Entity") through the process described in Paragraph 4, below. The Auditing Entity shall certify that the development, accuracy and application of data, is in accordance with the provisions of this Tariff. The Auditing Entity shall provide a Certified Public Accountant's attestation setting forth such certification ("CPA Attestation").

2. In addition to the CPA Attestation, the Auditing Entity will provide an audit report that will specify the audit process and procedures; identify the individual auditors and their functions; and include all copies of all written communications with Company personnel, summaries of all other communications related to the audit, descriptions of all data analysis techniques used, findings and recommendations. Also, the Auditing Entity shall make available all workpapers and other documentation and materials that support the CPA Attestation.

3. Company shall engage the Auditing Entity to perform the CPA Attestation duties through a competitive bidding process, evaluating each bidder

according to cost, experience, competency and familiarity with the industry and the regulatory environment. The requesting Customer(s) shall have the right to approve the content of the Request for Proposal and Company's selection of the auditing entity, which approval shall not be unreasonably withheld. If necessary, and after good faith efforts have not resulted in the Company's obtaining an Auditing Entity to provide the CPA Attestation pursuant to this Paragraph 4, the requesting Customer(s) and the Company agree to negotiate in good faith the scope of work that may be needed to provide a CPA Attestation and to accommodate the American Institute of Certified Public Accountants Code of Professional Conduct.

4. In the event an independent audit is performed with respect to a Service Year and the Company determines that the Annual True-Up is incorrect, the Annual True-Up required by Paragraph L of this Tariff may be subsequently adjusted pursuant to the provisions of this Tariff.

5. The reasonable and prudent cost of the Auditing Entity's services and Company's reasonable and prudent costs of engaging the Auditing Entity and providing information to the Auditing Entity and the Customer shall be included as part of the transmission costs charged to the Customers under this Tariff.

Formula rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission.

application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expense under the formula rate shall not open review of other components of the formula rate.

Calculation of Primary Distribution Revenue Requirements

For Customer-owned distribution facilities utilized by the Company for purposes of providing wholesale transmission service, effective as of the June billing month of each year , the Company will credit each monthly bill rendered to the Customer with one-twelfth of the annual costs determined by multiplying the sum of the applicable Customer's: (i) Distribution Plant Assets; (ii) Shared Substation Assets, and; (iii) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Primary Distribution Carrying Charge based upon previous calendar year data. The Primary Distribution Carrying Charge shall be calculated as follows for the applicable Customer:

I. The Primary Distribution System Carrying Charge shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit, divided by Total Primary Distribution Plant.

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

1. Primary Investment Base will be (a) Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Primary Materials and Supplies, plus (h) Primary Related Prepayments, plus (i) Primary Related Cash Working Capital.

a) Primary Distribution Plant shall equal the Customer's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Allocation Study.

b) Primary Related General Plant shall equal the Customer's Investment in General Plant excluding investment in specific buildings and facilities allocated to Company, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total Customer's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

c) Primary Plant Held for Future Use shall equal the Customer's Account

105, multiplied by the Primary Land Allocation Factor from the Distribution Allocation Study.

d) Primary Depreciation Reserve shall equal the Customer's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above,

e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

g) Primary Materials and Supplies shall equal the Customer's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

h) Primary Related Prepayments shall equal the Customer's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

i) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

2. Cost of Capital Rate will equal (a) the Customer's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (e) 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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of the Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the Customer's preferred stock then outstanding and the Imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE), shall be the product of the allowed ROEs shall be 11.14% as per FERC's Order on Rehearing Issued on March 24, 2008-in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679.[1] To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \text{ x } FT}{1\text{-}FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \text{ x } ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (l)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (1)(A)(2)(b) above.

B. Primary Depreciation Expense shall equal Customer's electric distribution-related depreciation expense as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(l)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the Customer's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the Customer's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(I)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the Customer's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Allocation Study.

G. Primary Related Administrative and General Expenses shall equal the Customer's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

H. Primary Related Revenue Credit shall equal Customer's Other Operating Revenues excluding any revenues from network distribution transactions, multiplied by the Primary O&M Allocation Factor as defined in (I)(A)(1)(b).

For Company-owned facilities utilized by the Customer for purposes of providing retail distribution service, effective as of the June billing month of each year, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual costs determined by multiplying the sum of the Company's: (i) Transmission Assets (ii) Distribution Plant Assets; (iii) Shared Substation Assets, and; (iv) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Annual Facilities Carrying Charge for Transmission Facilities - based upon previous calendar year data. In addition, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual cost for pole and tower attachments. The Annual Facilities Charge for Transmission Facilities shall be calculated as follows:

1. The Annual Facilities Carrying Charge for Transmission Facilities shall be calculated annually based on actual calendar year data as reported in the FERC

Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D)Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Operation and Maintenance Expense, and (G) Transmission Related Administrative and General Expenses, divided by Total Transmission Plant.

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

1. **Transmission Investment Base** will be (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Income Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Materials and Supplies, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Related Prepayments, plus (k) Transmission Related Cash Working Capital.

a) **Transmission Plant** shall equal NEP's balance of Total Investment in Transmission Plant in FERC Accounts 350 – 359, plus NEP's Total Investment in Distribution Plant in FERC Accounts 360-369 excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases).

b) **Transmission Related General Plant** shall equal NEP's balance of investment in General Plant in FERC Accounts 389 to 399 excluding General Plant related to NEP's generation facilities.

c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC account 105 excluding generation-related plant held for future use.

d) **Transmission Related Construction Work in Progress** shall equal the portion of NEP's investment in Transmission related projects as recorded in FERC Account 107 consistent with Commission Orders.

e) **Transmission Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve in FERC Account 108, excluding any generation-related depreciation reserve.

f) **Transmission Related Accumulated Deferred Income Taxes** shall equal the net of NEP's Total Accumulated Deferred Income Taxes in

FERC Accounts 281-283 and FERC Account 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities. and any Accumulated Deferred Taxes associated with non-utility assets or generation facilities.

g) **Transmission Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt in FERC Account 189.

h) **Transmission Related Materials and Supplies** shall equal NEP's balance of Materials and Supplies in FERC Account 154.

i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission Orders.

j) **Transmission Related Prepayments** shall equal NEP's balance of prepayments in FERC Account 165 excluding any prepayments related to NEP's ongoing generation-related activities.

k) **Transmission Related Cash Working Capital** shall be 12.5% allowance (45 days/360) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. **Cost of Capital Rate**

The Cost of Capital Rate shall equal (a) NEP'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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of NEP's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE) shall be the product of 11.14% as per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and NEP's imputed common equity capitalization ratio of 50%, To the

extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to the filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{\text{A X FT}}{\text{1-FT}}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)()2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{\text{(A + Federal Income Tax) x ST}}{1 - \text{ST}}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and the Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Transmission Related Depreciation Expense** shall equal the Depreciation Expense in FERC Account 403 associated with Transmission Plant, Transmission Related General Plant and Transmission Plant Held for Future Use as described in Sections (I)(A)(1)(a), (b) and (c), less the amortization of AFUDC Regulatory Liability as recorded in FERC Account 407.3.

C. **Transmission Related Amortization of Loss on Reacquired Debt** shall equal NEP's amortization of the balance on Loss on Reacquired Debt recorded in FERC Account 428.1.

D. **Transmission Related Amortization of Investment Tax Credits** shall equal the amortization of Investment Tax Credits recorded in FERC Account 411.4, excluding any ITC credits specifically identified as generation-related.

E. **Transmission Related Municipal Tax Expense** shall equal NEP's total municipal tax expense recorded in FERC Account 408.1 excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

F. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems.

G. **Transmission Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses recorded in FERC Accounts 920-935, less production-related Administrative and General Expenses associated with joint-owned production units, plus Payroll Taxes.

The Company's rate for tower attachments is $49.28 per tower. The Company's rate for pole attachments is $253.27 per pole. The annual cost for the Customer to attach to the Company's towers and poles will be the product of the respective rate multiplied by the number of respective attachments as specified in the Customer's Service Agreement.

The Customer shall afford to the Company the opportunity at any time to make such reasonable examination of the Customer's books and records as the Company may request for the purpose of verifying the basis for calculation of the foregoing monthly credits.

The foregoing credits shall be reviewed annually and upon substantial addition, modification or retirement of the Customer's generating and transmission facilities or other substantial change in circumstances, any changes therein shall be reflected in a revised Service Agreement.

C.

If the Service Agreement is amended by mutual consent of the parties, the terms of the agreement as so amended shall be applicable to the Customer's service on and after the effective date specified therein. If no such amendment has been executed prior to the date specified in the Customer's notice, the Customer may at its election terminate the Service Agreement forthwith or upon such date within the following twelve months as it may specify to the Company in writing.

D. <u>Amendments.</u>

The Company reserves the right to amend the foregoing terms and conditions in the manner set forth in its General Terms and Conditions governing primary service for resale.

NEW ENGLAND POWER COMPANY

Schedule III-C

THIS SECTION INTENTIONALLY LEFT BLANK

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

FORM OF SERVICE AGREEMENT

Dated:

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

20 Turnpike Road
Westborough, Massachusetts 01581

and

(the "Customer")

1. Scope of Service Agreement. The Company agrees to sell and transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I	- General Terms and Conditions
Schedule II	- Rate Provisions
Schedule III	- Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By ______________________________
Vice-President

APPENDIX A

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:

2. Name of District:

3. Service Under:

4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)

5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)

6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)

7. Entitlements:

   A. On Customer System (Schedule III-C - Paragraph C.2.(a))

   B. Off Customer System (Schedule III-C - Paragraph C.2.(b))

8. Customer Generation excluded from

Firm Capacity Calculation:

(Schedule III-C - Paragraph C.3.c)

9. Firm Capacity:

(Schedule III-C - Paragraph C.3.c)

10. Integrated Generating, Transmission and Facilities Credits Payable by Company:

(Schedule III-B - Paragraph B.4.b)

11. Primary Service for Resale:

Delivery Points	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments

12. Minimum Demand KW: None

13. Minimum Term: None

14. Transmission Service for Partial Requirements Customers:

Transmission Delivery Point(s)	KV (Nominal)	Subtransmission Delivery Point(s)	KV (Nominal)

SERVICE AGREEMENT

Between

NEW ENGLAND POWER COMPANY

And

MASSACHUSETTS ELECTRIC COMPANY

And

NANTUCKET ELECTRIC COMPANY

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

Dated: February 15, 1974

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

and

MASSACHUSETTS ELECTRIC COMPANY and
NANTUCKET ELECTRIC COMPANY
Massachusetts corporations (the "Customer")

1. Scope of Service Agreement. The Company agrees to transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I - General Terms and Conditions

Schedule II - Rate Provisions

Schedule III - Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

NONE

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By: ______________________________

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY

By: ______________________________

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:	Massachusetts Electric Company, Nantucket Electric Company
2. Name of District:	Baystate West, Baystate South, and North and Granite
3. Service Under:	Schedules III-B of the Tariff and Settlements accepted by the Commission in Docket Nos. ER97-678-000, ER97-2800-000, and ER10-523-000.
4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	The Naragansett Electric Company, Western Mass Electric Company Hingham Municipal Lighting Plant, Boston Edison
5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Not Applicable. Mass Electric no longer takes generation service under Tariff No. 1. Contract Termination Charge provided pursuant to Contract Termination Charge Amendment
6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)	Not applicable
7. Entitlements:	
A. On Customer System (Schedule III-C Paragraph C.2.(a))	None
B. Off Customer System (Schedule III-C Paragraph C.2.(b))	None
8. Customer Generation excluded from Firm Capacity Calculation: (Schedule III-C – Paragraph C.3.c)	None
9. Firm Capacity: (Schedule III-C – Paragraph C.3.c)	None

10. Integrated Generating, Transmission and Facilities Credits - Schedule III-B: Company and Customer acknowledge that the formula rates and Company's billings to Customer under Schedule III-B shall be subject to and shall comply with the terms and conditions of the Uncontested Settlement Agreement approved by the FERC in FERC Docket No. ER10-523-000 (Settlement), *New England Power Company*, [ ].

(Schedule III-B - Paragraph B.4.b)

Payable by Company:

Customer Distribution Plant Assets Serving Wholesale Transmission Function:	Attachment 1	$4, 741, 264
Customer Shared Substation Assets:	Attachment 2	$2,365,249
Customer Buildings and Facilities	Attachment 3	$2,141,768

Payable by Customer:

Company Transmission Assets (13.8 and 23kV)	Attachment 4	$4, 075,372
Company Distribution Plant Assets	Attachment 5	$292,975
Company Shared Substation Assets:	Attachment 2	$8,190,969
Customer Attachments to Company Towers	Attachment 6	195
Customer Attachments to Company Poles	Attachment 6	858

Formula Rate Inputs:

1. Customer Post Retirement Benefits Other Than Pensions (PBOP) - ($18,300,000)

2. Customer Depreciation Rates

Transmission Accounts	**Rate**
352	1.56%
353	1.79%
354	1.54%
355	3.04%
356	2.49%
357	1.97%
358	-1.33%
359	0.27%

Distribution Accounts	**Rate**
361	2.44%
362	2.07%
364	3.41%
365	3.19%

366	2.56%
367.1	2.90%
368	
368.1	3.50%
368.2	3.77%
368.3	3.87%
369	
369.1	3.53%
369.20	2.90%
369.21	2.90%
369.22	0.00%
370	
370.1	4.23%
370.2	4.49%
370.3	4.10%
370.35	3.65%
371	0.00%
373	
373.1	5.44%
373.2	5.41%

General Accounts	**Rate**
390	2.05%
391	6.67%
392	6.67%
393	3.04%
394	5.59%
395	5.97%
396	6.67%
397	6.67%
397.1	3.83%
398	6.48%

11. Primary Service for Resale:

None. LNS transmission service is provided by New England Power Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP). Contract Termination Charge provided pursuant to Contract Termination Charge Amendment. Nothing contained herein is intended to

	modify or otherwise affect the settlements accepted by the Commission in Docket Nos. ER97-678-000 and ER97-2800-000. In the event of a conflict between the Contract Termination Charge Amendment and the settlements, the settlements shall govern.
12. Minimum Demand KW:	None
13. Minimum Term:	None
14. Transmission Service for Partial Requirements Customers:	LNS transmission service provided by New England Power Company (NEP) to Massachusetts Electric Company and Nantucket Electric Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP.)

Massachusetts Electric Company
Distribution Plant Assets Serving NEP Wholesale Transmission Functions

Line No	Municipality Served by NEP		Plant In-Service Facilities		Distribution Asset Investment	Source
1	Georgetown	$	422,084	$	422,084	Internal Plant Records
2	Groveland		120,977	$	120,977	Internal Plant Records
3	Hull		942,574	$	942,574	Internal Plant Records
4	Ipswich		1,751,903	$	1,751,903	Internal Plant Records
5	Merrimac		157,256	$	157,256	Internal Plant Records
6	Princetown		100,777	$	100,777	Internal Plant Records
7	Stamford (GMP)		85,982	$	85,982	Internal Plant Records
8	Rowley		479,715	$	479,715	Internal Plant Records
9	**Sub Total**	$	4,061,268	$	4,061,268	Sum of Lines 1 - 9
10	Salem-Pelham (GSE)	$	679,996	$	679,996	Internal Plant Records
11	**Total MECO Distribution Assets Serving**					
12	**NEP Municipal Customers**			$	4,741,264	Line 9 + Line 10

Notes:

(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

	Location	Location ID	A ——Square Footage—— NEP	B MECO	C Total	D Nep Land Value	E Meco Land Value	F ——Devices—— NEP	G MECO	H Total	I Nep Device Value	J Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
1.	NEP - SUB #6 WEBSTER STREET, W	001	33,750	28,500	62,250	17,148.38	339,799.87	8	61	69	3,999.32	56,841.34	1,796,140.79	11,386.33	6,761,590.60	190,827.40
2.	NEP - SUB #8 VERNON HILL	002	17,500	57,950	75,450	136,084.67	49,047.90	4	14	18	6,110.83	22,550.58	735,612.90	109,279.64	962,496.57	16,384.95
3.	NEP - SUB #21 LEICESTER	003	7,560	15,120	22,680	19,796.58	44,761.62	4	2	6	8,817.93	332.15	561,537.70	16,137.40	850,633.55	15,140.49
4.	NEP - SUB #24 GREENDALE PTF	004	37,400	21,550	58,950	238,890.21	109,001.39	7	21	28	14,444.13	41,310.08	4,109,288.07	16,137.40	3,206,592.41	79,478.00
5.	NEP - SUB #25 NASHUA STREET, W	005	20,776	23,512	44,288	97,681.31	15,377.30	6	14	20	78,288.99	23,720.37	2,151,133.22	98,171.36	2,820,248.89	14,329.60
6.	NEP - SUB #26 PONDVILLE	006	8,040	9,360	17,400	80,452.92	3,873.22	4	6	10	14,140.14	656.50	375,558.23	106,661.30	276,418.81	2,052.41
7.	NEP - SUB #27 BLOOMINGDALE	007	13,775	10,150	23,925	248,049.17	17,029.07	4	13	17	40,986.08	6,444.75	2,135,646.29	51,759.71	2,705,183.27	11,321.79
8.	NEP - SUB #41 TEMPLE ST-W BOYL	008	1,950	2,080	4,030	0.00	2,378.70	1	1	2	0.00	299.27	183.70	136,564.51	74,303.10	1,300.69
9.	NEP - SUB #207 LITCHFIELD STRE	009	0	0	0	36,984.00	140,975.32	0	0	0	0.00	30,796.41	1,303,900.22	0.00	2,686,493.04	0.00
10.	NEP - SUB #210 DUNSTABLE	010	3,750	3,750	7,500	75,468.05	4,165.27	4	1	5	1,500.14	3,490.92	278,573.78	0.00	355,200.50	4,875.37
11.	NEP - SUB #219 PROSPECT STREET	011	11,970	13,375	25,345	76,101.20	18,409.48	9	10	19	0.00	75,827.71	641,593.23	38,034.05	849,892.88	44,614.38
12.	NEP - SUB #227 LAUREL CIRCLE,	012	15,990	11,960	27,950	600,988.41	245,407.00	4	2	6	178,988.42	0.00	2,238,487.70	40,158.60	727,652.17	140,397.34
13.	NEP - SUB #304 MILLBURY #4	013	9,520	12,320	21,840	157,924.59	20,012.00	4	9	13	44,478.03	1,915.09	1,927,526.30	316,819.78	1,021,561.81	9,312.50
14.	NEP - SUB #306 SHREWSBURY	014	14,875	13,125	28,000	32,474.60	46,090.07	5	3	8	0.00	15,295.78	847,189.17	119,877.40	2,006,414.58	34,047.52
15.	NEP - SUB #328 NORTH GRAFTON	015	6,375	5,625	12,000	5,408.09	39,559.05	1	2	3	935.44	2,542.06	163,990.03	15,224.09	85,808.15	21,864.99
16.	NEP - SUB #401 MAIN STREET - W	016	9,000	6,500	15,500	0.00	0.00	7	5	12	0.00	0.00	0.00	3,158.97	0.00	0.00
17.	NEP - SUB #406 NORTH OXFORD #2	017	12,240	10,840	23,080	118,145.34	65,534.23	3	5	8	39,103.03	2,205.10	1,299,621.99	0.00	1,493,058.55	35,579.71
18.	NEP - SUB #412 EAST WEBSTER	018	12,878	25,482	38,360	207,553.68	110,487.00	6	13	19	137,040.00	323.98	2,817,573.29	79,932.26	2,153,857.32	37,192.80
19.	MECO - SUB #413 SNOW STREET, S	019	0	0	0	0.00	81,294.73	0	0	0	0.00	14,711.64	0.00	231,640.68	7,401,980.00	0.00
20.	NEP - SUB #415 WEST CHARLETON	020	17,110	11,890	29,000	190,555.39	47,786.62	2	3	5	49,046.15	0.00	1,096,140.65	0.00	502,023.03	28,194.11
21.	NEP - SUB #525 LASHAWAY	021	1,200	2,500	3,700	38,890.22	7,817.38	4	5	9	9,335.05	6,498.95	233,033.30	107,555.40	389,801.62	5,423.31
22.	NEP - SUB #552 MEADOW STREET -	022	29,205	16,240	45,445	209,637.20	60,117.52	8	3	11	228,045.17	904.09	3,310,501.64	31,464.68	805,226.88	39,289.06
23.	NEP - SUB #601 PARK STREET P	023	11,550	23,300	34,850	36,713.97	135,802.58	7	20	27	63.84	22,894.71	1,099,361.76	137,112.25	1,008,058.37	50,941.57
24.	NEP - SUB #602 WESTMINSTER	024	9,000	10,800	19,800	19,518.20	5,440.57	3	3	6	8,941.41	922.14	165,817.71	24,594.25	309,240.19	2,933.81
25.	NEP - SUB #609 EAST WESTMINSTE	025	3,800	9,500	13,300	44,111.26	1,376.27	5	2	7	1,213.54	806.54	531,172.80	15,117.88	380,689.39	969.31
26.	NEP - SUB #612 EAST WINCHENDON	026	8,880	8,520	17,400	111,172.45	7,649.08	2	2	4	22,780.00	0.00	787,894.42	31,855.38	538,392.60	3,903.33
27.	NEP - SUB #1 WEST STREET	027	25,004	36,398	61,402	26,453.92	36,370.01	9	18	27	4,770.78	45,212.59	415,169.02	65,831.15	1,147,241.68	29,879.22
28.	NEP - SUB #7 MINK STREET	028	15,840	19,272	35,112	41,702.98	37,246.86	4	9	13	0.00	6,148.60	928,068.07	18,862.56	764,996.04	18,693.98
29.	NEP - SUB. #8 CHARTLEY POND, A	029	24,800	15,525	40,325	66,217.53	32,932.66	6	10	16	11,872.40	3,379.99	2,190,887.93	22,890.77	3,495,833.41	21,521.08
30.	NEP - SUB #9 READ STREET PTF	030	32,700	25,200	57,900	84,095.92	96,526.99	14	14	28	26,493.15	348.54	4,675,929.66	32,914.00	3,628,462.96	54,692.71
31.	NEP - SWANSEA SUB -- PTF	031	0	9,000	0	134,397.38	0.00	5	9	14	10,545.75	6,428.78	1,255,762.64	49,845.12	905,962.60	2,295.72
32.	NEP - DIGHTON SUB	032	0	6,750	0	52,861.64	0.00	5	5	10	12,125.45	5,932.46	336,047.87	70,054.15	501,234.51	2,966.23
33.	NEP - ROBINSON AVE SUB -- PTF	033	0	0	0	63,115.69	0.00	0	0	0	74,235.01	0.00	1,712,980.55	27,175.66	0.00	0.00
34.	NEP - HATHAWAY SUB	034	114,952	30,180	145,132	4,749.00	0.00	6	21	27	39,594.75	0.00	862,668.57	0.00	0.00	0.00
35.	NEP - BELL ROCK RD SUB -- PTF	035	0	0	0	13,734.74	0.00	0	0	0	48,914.56	0.00	819,854.24	31,784.11	0.00	0.00
36.	NEP - SUB #310 SOUTH MARLBOROU	036	4,000	4,500	8,500	51,975.36	3,519.59	7	5	12	5,248.26	6,506.94	982,969.37	0.00	0.00	0.00
37.	NEP - SUB #311 MARLBOROUGH - F	037	7,614	24,255	31,869	5,231.34	63,366.89	6	8	14	26,631.52	30,927.17	2,101,730.24	29,702.71	462,640.63	5,451.82
38.	NEP - SUB #312 WESTBOROUGH P	038	9,849	14,700	24,549	71,564.72	20,055.97	9	8	17	33,433.95	5,358.04	2,876,156.00	19,198.82	1,175,765.83	28,393.74
39.	NEP - SUB #313 WOODSIDE, NORTH	039	15,727	11,719	27,446	34,641.37	28,783.50	6	4	10	18,287.95	2,355.50	3,102,550.08	58,586.97	999,998.30	10,883.00
															1,318,005.36	17,906.25
														22,107.04		

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

01/28/2010

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

	Location	Location ID	A	B	C	D	E	F	G	H	I	J				
			----Square Footage---- NEP	MECO	Total	Nep Land Value	Meco Land Value	------Devices------ NEP	MECO	Total	Nep Device Value	Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
40.	NEP - SUB #314 EAST MAIN STREE	040	10,875	11,600	22,475	191,168.61	10,144.94	2	4	6	60,031.84	4,329.93	1,235,573.76	138,685.35	360,067.25	6,352.30
41.	NEP - SUB #318 NORTH MARLBOROU	041	14,352	11,394	25,746	319,510.00	55,836.00	2	1	3	172,284.00	0.00	1,162,587.03	198,837.38	1,322,291.38	31,122.99
42.	NEP - SUB #320 WHITINS POND	042	10,140	20,410	30,550	107,256.91	11,975.33	2	4	6	55,392.17	63,583.00	3,087,458.20	108,588.30	2,549,580.42	25,166.83
43.	NEP - SUB #321 UXBRIDGE PTF	043	40,500	101,400	141,900	227,761.21	56,829.90	17	3	20	185,812.54	0.00	3,315,576.24	190,630.04	1,713,685.85	16,219.25
44.	NEP - SUB #335 DEPOT STREET	044	8,814	10,735	19,549	12,848.46	92,564.27	4	14	18	0.00	6,903.65	863,784.88	7,055.09	1,785,720.87	43,271.22
45.	NEP - SUB #336 ROCKY HILL, MIL	045	12,285	16,065	28,350	85,206.00	19,724.00	2	2	4	119,416.00	0.00	2,732,838.62	107,994.24	1,345,186.21	8,546.41
46.	NEP - SUB #344 BEAVER POND --	046	14,280	11,620	25,900	306,348.94	10,172.50	7	8	15	119,442.30	1,449.12	2,518,782.02	201,126.71	1,989,604.48	6,285.42
47.	NEP - SUB #348 UNION ST PTF	047	0	16,150	0	114,448.57	0.00	7	10	17	81,189.66	0.00	2,790,966.91	94,817.01	664,886.55	0.00
48.	NEP - SUB #3422 SOUTH WRENTHAM	048	30,526	23,714	54,240	100,799.84	24,437.91	6	19	25	26,375.79	37,662.82	3,143,914.89	64,115.29	5,662,290.77	22,792.73
49.	NEP - SUB #1 FIELD STREET	049	13,750	151,850	165,600	379,343.86	183,207.68	8	45	53	14,131.00	46,457.54	5,025,804.45	359,856.95	5,275,326.98	22,216.68
50.	NEP - SUB #9 EAST WEYMOUTH	050	4,800	9,680	14,480	15,311.88	143,742.00	4	15	19	8,911.09	33,099.80	415,833.17	17,271.30	1,417,650.78	54,617.98
51.	NEP - SUB #11 NORTH QUINCY	051	40,236	2,100	42,336	677,183.52	27,735.86	7	13	20	170,123.42	19,413.83	6,537,136.31	144,168.53	1,266,013.74	33,155.00
52.	NEP - SUB #12 MID-WEYMOUTH --	052	17,360	27,860	45,220	151,158.94	11,093.41	4	3	7	52,196.21	84,837.00	1,449,566.28	115,500.32	2,246,869.92	52,734.62
53.	MECO - SUB #95 PHILLIPS LANE,	053	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	3,019,216.13	0.00
54.	NEP - SUB #97 SOUTH RANDOLPH	054	8,640	13,635	22,275	339,768.52	58,090.00	2	4	6	28,203.45	2,130.00	2,230,762.72	226,775.55	2,323,492.94	23,243.04
55.	NEP - SUB #507 WILBRAHAM	055	6,000	6,900	12,900	63,192.39	149,857.08	2	6	8	0.00	161,900.00	1,045,554.74	33,801.61	1,295,153.93	110,173.53
56.	NEP - SUB #508 EAST LONGMEADOW	056	11,700	6,500	18,200	82,407.17	38,715.44	7	6	13	4,664.42	1,418.66	1,151,328.01	31,580.23	965,739.75	25,654.10
57.	NEP - SUB #509 BELCHERTOWN	057	5,060	7,590	12,650	27,536.74	31,336.61	2	3	5	14,495.00	42,682.64	561,030.13	25,219.04	707,708.61	29,607.70
58.	NEP - SUB #303 LITTLE REST ROA	058	10,220	14,000	24,220	312,780.67	71,683.00	2	4	6	92,517.00	357.86	1,411,423.58	242,468.31	710,356.89	30,369.50
59.	NEP - SUB #522 SHAKER ROAD	059	8,160	9,240	17,400	24,850.82	88,505.33	2	2	4	57,427.68	0.00	771,049.83	41,909.63	528,038.58	41,509.00
60.	NEP - SUB #523 THORNDIKE	060	0	13,200	0	405,595.32	0.00	2	3	5	69,808.00	908.19	1,666,914.85	234,826.49	545,665.51	363.28
61.	NEP - SUB #524 HAMPDEN	061	5,369	5,005	10,374	14,040.94	16,346.30	1	2	3	0.00	22,300.89	165,913.05	6,774.75	410,444.32	15,892.10
62.	MECO - SUB #527 FIVE CORNERS,	062	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	1,597,270.96	0.00
63.	NEP - SUB #604 BARRE-FORMERLY	063	3,600	16,000	19,600	48,228.30	11,438.51	4	7	11	6,950.95	0.00	283,554.43	43,792.35	418,718.88	2,101.25
64.	NEP - SUB #704 SHUTESBURY -- P	065	6,600	2,800	9,400	96,594.12	6,058.21	2	1	3	72,821.00	9,209.37	911,982.61	53,046.63	112,601.32	10,393.36
65.	NEP - SUB #705 WENDELL DEPOT	066	8,160	9,240	17,400	75,205.99	6,389.78	2	3	5	44,332.66	4,904.20	826,983.64	66,533.98	712,796.98	4,958.49
66.	MECO - SUB #1103 LENOX DEPOT,	067	0	0	0	0.00	101,199.01	0	0	0	0.00	16,600.34	0.00	0.00	856,447.37	0.00
67.	NEP - SUB #7 REVERE PTF	068	31,000	0	62,500	0.00	153,280.41	5	43	48	0.00	38,160.63	2,370,342.93	0.00	2,991,494.69	80,003.42
68.	NEP - SUB #16 MAPLEWOOD -- PTF	069	10,800	22,374	33,174	6,202.17	170,930.10	8	20	28	0.00	50,797.72	2,946,953.29	4,182.74	3,094,914.77	70,167.75
69.	NEP - SUB #37 EVERETT, EVERETT	070	51,650	66,425	118,075	122,807.89	43,553.49	14	35	49	0.00	8,792.23	2,970,854.66	69,091.72	861,939.98	21,562.24
70.	NEP - SUB #29 WEST SALEM	071	38,395	32,986	71,381	695,562.86	47,029.49	9	12	21	95,116.17	1,789.45	3,498,402.30	375,768.98	2,360,736.22	26,064.12
71.	NEP - SUB #49 RAILYARD, SALEM,	072	10,935	9,315	20,250	29,865.00	2,852.00	4	5	9	48,346.73	1,276.00	3,426,979.90	40,599.34	2,029,333.05	2,107.13
72.	NEP - SUB #51 EAST BEVERLY - C	073	18,977	43,375	62,352	149,200.19	24,008.01	8	22	30	47,893.07	37,803.43	4,518,100.04	138,903.64	5,266,867.31	17,390.21
73.	NEP - SUB #21 LYNN, LYNN -- PT	074	17,072	74,635	91,707	17,624.42	220,842.21	5	76	81	0.00	38,789.59	1,298,285.74	14,342.75	8,862,470.75	43,514.14
74.	NEP - SUB #2 NORTH CHELMSFORD	075	12,000	23,900	35,900	19,522.42	175,421.24	6	21	27	5,497.47	21,731.99	1,985,884.48	17,272.01	4,642,617.53	63,472.17
75.	NEP - SUB #3 PERRY STREET	076	11,200	10,640	21,840	115,075.11	88,187.38	2	48	50	45,243.12	32,262.13	603,670.87	99,497.99	1,975,149.39	46,512.97
76.	NEP - SUB #16 MEADOWBROOK-OFF	077	24,000	31,900	55,900	100,985.04	40,848.74	6	23	29	9,514.00	15,105.58	967,041.04	65,177.72	2,943,978.02	20,661.71
77.	NEP - SUB. #45 SOUTH BROADWAY	078	15,705	8,908	24,613	111,689.53	21,848.30	4	6	10	16,516.00	29,083.85	1,828,299.74	50,330.04	782,251.66	25,574.94
78.	NEP - SUB #59 EAST TEWKSBURY	079	6,000	6,500	12,500	110,272.85	9,905.57	4	9	13	40,354.09	0.00	1,884,782.19	85,279.02	3,119,773.89	4,754.67

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

01/28/2010

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

			A	B	C	D	E	F	G	H	I	J				
	Location	Location ID	----Square Footage---- NEP	MECO	Total	Nep Land Value	Meco Land Value	----Devices---- NEP	MECO	Total	Nep Device Value	Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
79.	NEP - SUB #70 BILLERICA	080	10,530	21,710	32,240	4,761.10	83,719.89	4	19	23	8,431.80	9,522.47	4,852,186.40	10,171.63	2,990,118.28	28,998.87
80.	NEP - SUB #75 EAST DRACUT	081	8,040	9,360	17,400	12,813.53	13,974.72	2	3	5	23,447.92	815.56	3,319,100.74	20,961.15	1,558,804.96	6,783.94
81.	NEP - SUB #78 NORTH DRACUT	082	10,680	28,200	38,880	144,783.38	22,444.27	2	2	4	9,410.47	39,996.43	770,518.42	109,716.62	762,073.44	26,163.66
82.	NEP - SUB #92 PINEHURST	083	10,640	8,680	19,320	267,177.65	11,924.63	5	8	13	47,710.17	9,130.60	1,989,419.01	149,403.76	1,647,173.28	10,078.52
83.	NEP - SUB #18 KING STREET	084	0	19,800	0	110,215.27	0.00	19	2	21	40,511.97	0.00	11,789,254.72	26,726.41	0.00	0.00
84.	NEP - SUB #8A WEST ANDOVER	085	15,120	10,530	25,650	151,641.95	36,716.39	5	13	18	46,092.62	42,073.55	2,333,352.85	95,537.11	1,649,443.82	33,332.34
85.	NEP - SUB #54 BURTT RD- EXECUT	086	0	16,520	0	246,969.32	0.00	6	4	10	134,335.00	0.00	2,754,549.40	188,653.34	2,232,833.56	0.00
86.	NEP - SUB #63 WEST METHUEN - P	087	18,639	14,592	33,231	196,432.79	15,400.30	8	10	18	407.01	19,610.21	2,160,477.11	86,479.77	1,512,697.77	17,352.81
87.	NEP - SUB #74 EAST METHUEN –	088	11,640	19,800	31,440	97,311.63	20,092.45	6	9	15	35,732.93	17,635.66	2,814,347.58	82,726.62	2,359,489.63	14,492.49
88.	MECO - AUBURN ST SUB 115KV	089	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	62,943.48	0.00
89.	NEP - BRIDGEWATER SUB -- PTF	090	0	0	0	305,750.83	0.00	0	0	0	217,443.36	0.00	12,996,518.82	0.00	0.00	0.00
90.	NEP - SUB #201 AYER PTF	092	58,240	35,840	94,080	223,543.03	5,966.09	30	3	33	22,351.78	28.65	5,395,456.42	87,201.67	233,119.15	3,719.06
91.	NEP - SUB #216 FITCH ROAD PT	093	34,400	20,250	54,650	94,593.14	8,516.50	15	1	16	56,018.92	0.00	5,678,229.28	38,547.94	1,475,879.96	5,361.14
92.	NEP - SUB #225 PRATTS JUNCTION	094	0	1,750	0	210,414.14	0.00	29	8	37	263,153.42	0.00	21,096,309.95	57,693.34	1,319,187.82	0.00
93.	NEP - SUB #237 SANDY POND, AYE	095	252,000	81,000	333,000	747,675.13	1,793.24	42	7	49	296,243.06	5,357.07	20,311,680.95	224,167.72	286,109.52	5,948.67
94.	MECO - BATES ST SUB 14KV 115	096	0	0	0	0.00	0.00	5	25	30	0.00	2,948.93	0.00	0.00	2,427,634.92	491.59
95.	NEP - SUB #317 NORTHBOROUGH RO	097	69,680	30,160	99,840	317,729.16	33,189.41	20	18	38	68,342.34	0.00	8,270,334.34	128,359.75	1,676,061.68	23,162.89
96.	NEP - SUB #501 WARE #1 PTF	098	44,307	24,310	68,617	73,849.35	26,753.43	12	5	17	45,536.07	3,054.27	4,147,230.89	39,556.98	579,087.11	19,430.70
97.	NEP - SUB #503 PALMER - BLANCH	099	104,000	71,600	175,600	252,845.06	51,673.68	29	8	37	194,467.45	58,925.49	11,060,804.92	145,128.79	1,102,047.47	76,792.12
98.	NEP - SUB #702 CHESTNUT HILL	100	6,880	9,000	15,880	117,221.62	85,649.34	6	5	11	113,823.00	0.00	2,616,501.22	118,173.77	811,940.79	37,103.29
99.	NEP - SUB #21 ADAMS PTF	101	108,000	72,000	180,000	413,717.23	3,036.85	31	3	34	126,098.36	792.89	6,097,968.08	176,608.77	2,020,920.85	2,545.07
100.	NEP - SUB #22 TEWKSBURY PTF	102	590,600	205,600	796,200	340,429.45	6,341.92	81	1	82	528,463.37	2,298.03	36,420,515.92	94,346.14	453,210.23	6,974.43
101.	NEP - SUB #43 WARD HILL PTF	103	96,250	47,520	143,770	341,056.49	32,023.70	32	10	42	412,579.76	401.56	62,672,526.93	210,954.41	2,385,786.60	21,745.82
102.	NEP - DEERFIELD #5 SWITCHYARD-	104	7,098	9,703	16,801	141,803.44	3,363.01	4	2	6	9,333.21	0.00	681,298.37	85,002.25	85,028.35	1,420.87
103.	NEP - BEAR SWAMP - TRANSMISSIO	105	188,850	22,500	211,350	1,047,224.60	1,970.14	18	2	20	160,417.40	0.00	5,178,302.77	127,571.16	88,928.69	1,760.32
			2,753,335	2,181,519	4,883,184	14,967,805.97	4,628,335.68	775	1001	1776	5,825,769.39	1,492,221.58	361,881,055.75	8,190,969.11	165,227,835.59	2,365,249.04

Revised
Massachusetts Electric Company
Distribution Plant Assets Serving NEP Wholesale Transmission Functions
Buildings and Facilities

Line No	Mass Electric Location Identifiers	Building/Facility Description	FERC Accounts	(1) Total Mass Electric Investment	Source	(2) Facility Total Sq. Ft.	(3) Facility Area Used by NEP	(4)=(1)*((3)/(2)) (4) Investment Allocated to NEP
1	157, 192	Beverly, MA	390	$761,589	Internal Plant Records	40,230	1,600	$30,289
2	92, 296, 660	Leominster, MA	389, 390	804,671	Internal Plant Records	17,897	800	35,969
3	92, 160	North Andover, MA	389, 390	453,939	Internal Plant Records	106,786	800	3,401
4	92, 298, 323	Leeds (Northampton), MA	389, 390	1,676,832	Internal Plant Records	23,669	600	42,507
5	24858652	Northbridge/Sutton, MA	389, 390	13,663,277	Internal Plant Records	86,741	12,534	1,974,332
7	92, 309, 325	Worcester, MA	389, 390	6,812,142	Internal Plant Records	147,902	1,200	55,270
7	Total			$24,172,450				$2,141,768

New England Power Company Assets
Used by Massachusetts Electric Company
For Retail Distribution Service

Transmission Assets (13.8 and 23 kV)

Line No	NEP Location Identifier	NEP Circuit Identifier	Description	Total Plant In-Service Investment	Source
1	4205	1201	MH-12699 Washington St to Field St Sub	$0.00	Internal Plant Records
2	4206	1202	MH-12699 Washington St to Field St Sub	0.00	Internal Plant Records
3	4207	1213X	MH-12700 Washington St to Field St Sub	0.00	Internal Plant Records
4	4208	1219	MH-12700 Washington St to Field St Sub	52,946.16	Internal Plant Records
5	4209	1224	MH-12700 Washington St to Field St Sub	0.00	Internal Plant Records
6	4210	1225	MH-12700 Washington St to Field St Sub	43,448.35	Internal Plant Records
7	4211	2208	MH-12699 Washington St to W. Quincy Sub	1,240,922.54	Internal Plant Records
8	4212	2215	MH-12699 Washington St to W. Quincy Sub	195,496.45	Internal Plant Records
9	4213	2211	MH-12700 Washington St to W. Quincy Sub	806,490.31	Internal Plant Records
10	4214	2212	MH-12700 Washington St to W. Quincy Sub	59,684.57	Internal Plant Records
11	4215	2216	MH-12700 Washington St to W. Quincy Sub	154,364.13	Internal Plant Records
12	4252		Quincy BECO	1,522,019.97	Internal Plant Records
13	**Totals**			**$4,075,372.48**	Sum of Lines 1 - 12

Notes:

(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

New England Power Company Assets
Used by Massachusetts Electric Company
For Retail Distribution Service

Distribution Plant Assets

Line No	NEP Location Identifier	Description	Total Plant In-Service Investment	Source
1	15	Fitch Road Substation	$0.00	Internal Plant Records
2	86	Leicester Substation #321	0.00	Internal Plant Records
3	126	Millbury #3 Substation #303	0.00	Internal Plant Records
4	7006	North Attleboro Distribution Feeder 8-L2 Feeder	31,240.82	Internal Plant Records
5	7007	Westminster Sub to Digital Equipment 13.8 KV Feeder	18,620.83	Internal Plant Records
6	7008	#1 23 KV Line from Sub #63 to #2353 Line	44,279.97	Internal Plant Records
7	7009	#2 23 KV Line from Sub #63 to #2376 Line	31,352.83	Internal Plant Records
8	7010	13 KV Getaway from Sub #63 to NEP R/W's	25,552.13	Internal Plant Records
9	7011	#2301 & #2302 Lines 23 KV Taps	56,993.68	Internal Plant Records
10	7012	Line 70L1 13 KV Distribution Feeder	26,315.35	Internal Plant Records
11	7014	13.8 KV Line - Westminster	10,642.11	Internal Plant Records
12	7015	E5 and F6 Getaway Wsub #704 Shutesbury	13,273.88	Internal Plant Records
13	7017	Forge Park Industrial Development 13.8 KV Line	17,547.88	Internal Plant Records
14	8002	Metropolitan District Commission - Wachusett Dam	9,268.37	Internal Plant Records
15	8053	Water Street Sub - Mass Electric	1,872.70	Internal Plant Records
16	8054	Lawrence Street #1 Substation - Mass Electric	2,960.79	Internal Plant Records
17	8057	Malden #5 Station - Mass Electric	0.00	Internal Plant Records
18	8071	Hampshire Road Granite State Metering Point	3,053.87	Internal Plant Records
19	FR3	Sykes Road Substation	0.00	Internal Plant Records
20	**Totals**		**$292,975.21**	Sum of Lines 1 - 19

Notes:

(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

New England Power Company
Detail of Massachusetts Electric Line Attachments
NEP to MECO Integrated Facilities Usage Fees

Line No	District	NEP Pole Locations with MECO Line Attachments	Number of Poles	Number of Towers	Structure Numbers	Source
1	Worcester	#5 and #6 (Auburn)	45		1749A-1766, !768, 1769-1794	Internal Plant Records
2		#5 and #6 (Leicester)	5		1600-1604	Internal Plant Records
3		#127 and #128	5		1948-1952	Internal Plant Records
4		A1 and B2 (Greendale to Pratts Jct)		52	Towers 822-833, 835-874	Internal Plant Records
5				51	Towers 821A-874D including 852B&C, 873A, 874A-C	Internal Plant Records
6					excluding 848A, 849A, 850A, 854A, 865A, 870A, 872A	Internal Plant Records
7		**Worcester Totals**	**55**	**103**		Sum of Lines 1 - 5
8						
9	Palmer	Wilbrahan Sub #507	1		251	Internal Plant Records
10		E5 and F6 Lines	14		at Meadow St Sub #'s 1432-1437, 1437A, 1438-1444	Internal Plant Records
11			149		Meadow St - Lashaway Sub #'s 1306-1431, 1364L, 1363L,	Internal Plant Records
12					1346A, 1332S, 1285-1305	Internal Plant Records
13			31		Primary attachments on #14 Line #'s 63-72, 118, 250-271	Internal Plant Records
14			5		Primary attachments on #15 Line #'s 99-102, 155	Internal Plant Records
15			1		Secondary attachments on #15 Line #'s 4A	Internal Plant Records
16		**Palmer Totals**	**201**	**0**		Sum of Lines 9 - 15
17						
18	Gardner	#127 and #128	36		1569-1606	Internal Plant Records
19						
20		**Gardner Totals**	**36**	**0**		Sum of Line 18
21						
22	Hopedale	#5 and #6 Millbury - Auburn	119		1795-1910, 1887A, 1880A, 1881A and 1884A	Internal Plant Records
23		#11 and #12 Lines	110		Lackey Pond - Uxbridge Ser Twr 262-372	Internal Plant Records
24			48		Uxbridge Sub - Uxbridge Ser Twr 1-48	Internal Plant Records
25			117		321W0 Tap - Uxbridge Ser Twr - 2-118	Internal Plant Records
26		X24 Line	10		Feeder 310W5 attached to poles 1-5, 6A, 13-16	Internal Plant Records
27						
28		**Hopedale Totals**	**404**	**0**		Sum of Lines 22 - 26
29						
30	Southbridge	S-19 Line	18		239-252, 265-267, 135	Internal Plant Records
31						
32		**Southbridge Totals**	**18**	**0**		Sum of Line 30
33						
34	Attleboro	24 Rehoboth Tap	33		"K" frames #118-150	Internal Plant Records
35						
36		**Attleboro Totals**	**33**	**0**		Sum of Line 34
37						
38	North Adams	#7 and # 8 Lines	38		telephone lines, poles #381-440 plus 1 un-numbered	Internal Plant Records
39		G-17 Bennington-Adams Line		46	Feeder #1 attached to Q117 towers	Internal Plant Records
40		Q117 Adams - Walker		46		Internal Plant Records
41		N14	31		#63-72, 118, 250-271	Internal Plant Records
42		O15	6		#4A, 99-102, 155	Internal Plant Records
43		S197	30		Feeder #1019W1 getaway	Internal Plant Records
44						
45		**North Adams Totals**	**105**	**92**		Sum of Lines 38 - 43
46						
47	Malden	F-158S	6		#'s 148-153	Internal Plant Records
48						
49		**Malden Totals**	**6**	**0**		Sum of Line 47
50						
51		**Total Poles and Towers**	**858**	**195**		Sum of Lines 7,16,20, 28,32,36,45 and 49

FERC ELECTRIC TARIFF

SECOND~~FIRST~~ REVISED VOLUME NUMBER 1

OF

NEW ENGLAND POWER COMPANY

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this
Tariff should be addressed to:

Director of Rates
New England Power Company
40 Sylvan Road
Waltham, Massachusetts 02451

NEW ENGLAND POWER COMPANY

Primary Service for Resale

TABLE OF CONTENTS

NEW ENGLAND POWER COMPANY

Primary Service for Resale and Transmission Service for Partial Requirements Customers General Terms and Conditions

Schedule I

A. Tariff.

Primary Service for resale and transmission service for Partial Requirements Customers are available only upon execution of a Service Agreement with the Company in the form set forth hereinafter.

Each such Service Agreement will incorporate these general terms and conditions (Schedule I), the Company's currently effective rate for primary service for resale (Schedule II), the terms and conditions applicable to the type of service to be rendered at said rate (Schedule III) and the specific interconnection arrangements with the Customer.

The Company will file each such Service Agreement with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder.

B. Amendments.

It is agreed that the Company shall have the right at any time to amend the General Terms and Conditions set forth in this Schedule I to the tariff, the Rate Provisions set forth in Schedule II to the tariff, the Terms and Conditions governing specified types of service set forth in Schedule III to the tariff, and the form of Service Agreement set forth in Schedule IV to the tariff, by serving an appropriate statement of such amendment upon the Customer and filing the same with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order duly issued by such agency.

C. Regulation.

This tariff, any Service Agreement executed pursuant thereto, and all the rights, obligations and performance of the parties to such service agreement, are subject to the Federal Power Act and to all other applicable state and federal laws and to all duly promulgated rules, regulations and orders of the Federal Power Commission and any other regulatory agency having jurisdiction in the premises.

The obligations of the parties are further subject to and conditioned upon their securing and retaining all rights-of-way, franchises, locations, permits and other rights and approvals necessary in order to permit service to be rendered as set forth in the Service Agreement, and each party agrees to use its best efforts to secure and retain all such rights-of-way, franchises, and other rights and approvals.

D. Availability of primary service for resale.

Primary service for resale is available only to electric utilities (including municipalities) engaged in the distribution of electricity to the public, whose electric requirements are supplied in whole or in part by the Company, either directly or over facilities for the use of which the Company has contractual arrangements.

Electricity so supplied is available for the Customer's own use and for resale to ultimate customers in the Customer's service area as it may exist from time to time, which area shall consist of one or more Districts to be specified in the Service Agreement. If the Customer's service area consists of two or more Districts, all provisions of the tariff shall apply to each District separately.

Primary service for resale is also available for sales for resale by the Customer (1) to electric utilities served by the Customer as of the date of and as specified in the Service Agreement; (2) to additional electric utilities which shall then be specified in the Service Agreement; and (3) under convenience contracts for the supply of electricity to borderline customers. With reference to sales under (2) above, the Customer shall give to the Company seven years' notice of intention to serve such utilities; the Customer shall furnish such information as the Company may reasonably request; and the parties shall establish mutually agreeable reasonable terms in connection therewith.

Service for Resale to Interruptible Customers under Schedule III-C is available only to utilities who are also taking service under Schedule III-A or III-B.

The Customer's sources of supply other than the Company shall be specified in the Service Agreement; and seven years' notice shall be given by the Customer to the Company of a change in Customer's source or sources, and such change shall be implemented pursuant to mutually agreed upon reasonable terms.

E. Availability of transmission service.

The types of transmission service available to the Partial Requirements Customer are specified in Schedule III to the tariff, and the Company will consider requests for additional types of transmission service; in each case to the extent that the Company deems its existing and planned transmission capacity can accommodate such additional service without additional new construction. In cases where new construction may be required to accommodate additional types of transmission service, the Company reserves the right in its discretion either to refuse to undertake such further service, or to request financial assurance that any additional transmission investments and costs will be adequately provided for.

F. Character of primary electric service.

Electricity will be supplied in the form of three-phase, sixty-hertz alternating current at the nominal voltage or voltages specified in the Service Agreement.

The Company will maintain and operate its interconnected generating and transmission system, together with any delivery facilities required for service to the Customer, in accordance with good utility practice. The Company will use due diligence in maintaining an aggregate capacity of such facilities sufficiently in excess of current Demand to allow for the Customer's expected load growth, and the Customer will keep the Company informed as to expected trends of its load growth.

The Company shall not be liable in damages to the Customer for any failure to supply electricity nor to provide transmission service in accordance with the preceding paragraphs if prevented from doing so by reason of storm, flood, earthquake, fire, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or other public authority, or any cause beyond its reasonable control; and shall not be liable in damages to the Customer for any reduction in voltage or interruption of service resulting from the operation in accordance with good utility practice of an emergency load-reduction program; but in any such case the Company will exercise due diligence to remove the cause of any disability at the earliest practicable time. The Company and the Customer shall have the obligation to operate in accordance with good utility practice, including an emergency load reduction program, and upon request, to consult with each other in regards thereto.

G. Delivery and ownership of facilities.

1. All deliveries will be made a single delivery point in each District (which may also be used to serve other customers of the Company or affiliated companies of the New England Electric System), except where District load can be more feasibly served by multiple delivery points. The Service Agreement shall set forth with respect to each District of the

Customer's system the point or points of delivery, the delivery voltage or voltages and the ownership of transformation and metering equipment.

2. Deliveries at each delivery point will be made at a single voltage except as otherwise provided in the Service Agreement.

3. All lines, apparatus and other equipment up to the point of delivery shall be supplied, maintained and operated by the Company or affiliated companies of the New England Electric System, and all such equipment beyond such point of delivery shall be supplied, maintained and operated by the Customer. The Customer shall, however, supply free of cost a suitable place for the installation of the Company's metering equipment and any of the Company's lines, or other equipment which it is proper to locate on the Customer's property, and the Company shall have access to the Customer's property for all reasonable purposes in connection therewith.

4. All the Customer's lines, apparatus and equipment (and the maintenance, operation and adjustment of the same) which are connected to the facilities of the Company, and the maintenance, operation and adjustment of which may adversely affect the operation of the Company's facilities, shall be subject to the reasonable inspection and approval of the Company.

5. The Customer assumes all responsibility for electricity beyond the point of delivery, and the Company shall not be liable for damage to the person or property of the Customer or of its employees or of any other persons resulting from the use of electricity beyond the point of delivery.

Variations from the provisions of paragraphs 1 through 5 above will be permitted, in the discretion of the Company, if and to the extent that equitable adjustments are provided for and set forth in the Service Agreement.

H. Metering.

The Company reserves the right to determine the metering installations and will supply the metering equipment for determining the quantity and conditions of supply of electricity delivered hereunder. Any exceptions to this provision shall be reflected in the Service Agreement.

If at any time such equipment shall be found to be inaccurate by more than 2% up or down, the owner shall make it accurate and the charges and meter readings for the period of inaccuracy, so far as the same can reasonably be ascertained, shall be adjusted. However, no adjustment prior to the beginning of the next preceding month shall be made except by mutual agreement.

In addition to regular routine tests, the owner shall have any such meter tested at any time upon written request of the other party, and if such meter prove accurate within 2% up or down the expense of the test shall be borne by the party requesting the test.

I. Transmission losses.

Unless otherwise specified in the tariff, all losses incurred in providing transmission service hereunder shall be for the account of the Customer, and delivery of the aggregate quantity of electricity received for transmission, less such losses, shall constitute full performance by the Company. When segregation of energy flows is required to determine such losses, the Company will calculate the same in accordance with good engineering practice.

J. Billing and payment.

Bills for each month shall be rendered during the first part of the next succeeding month and shall be due when rendered.

As used herein the term “month” shall refer to the period between two meter readings each of which shall have been taken within two days of the end of successive calendar months.

When all or part of any bill shall remain unpaid for more than thirty (30) days after the rendering thereof by the Company, interest at the rate of 1 ½% per month shall accrue to the Company from and after the rendering of said bill and be payable to the Company on either: (1) such unpaid amount or (2) in the event the amount of the bill is disputed, the amount finally determined to be due and payable.

Notwithstanding the foregoing, no late payment penalty shall be imposed upon any customer where payment is made within forty-fine (45) days of the rendering of the bill by the Company provided that each of the following conditions are met: 1) the average prior calendar year’s monthly billing to such customer was less than $45,000; and 2) payment of such bill within thirty (30) days by such customer would cause undue hardship because of the fact that one or more part-time employees or officials are essential to the processing of payment by such customer. A letter from an appropriate official of a customer certifying that one or more part-time employees are essential to the processing of payment shall constitute satisfactory evidence that condition 2 herein has been met.

In addition, no late payment penalty shall be imposed upon any customer electing to make installment payments with respect to any bill so long as the weighted average payment date, based on the amount of each payment, is no later than 30 days after the date of the rendering of the bill.

K. Remedies.

If any bill remains unpaid for more than sixty days, except amounts in dispute, the Company may apply to the regulatory agency having jurisdiction to suspend delivery of electricity until full payment has been made of all amounts due.

If either party shall have defaulted in any of its obligations and such default shall have continued for and not been remedied within sixty days after receipt of a written notice from the other party specifying the nature of such default in reasonable detail, the other party may by written notice terminate the Service Agreement at the end of the next succeeding calendar month. No delay by either party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which other party is legally entitled.

L. Hours of Labor.

The Company agrees to comply with the provisions of the General Laws of Massachusetts, Chapter 149, Section 34, as amended, with reference to the hours of laborers, workmen or mechanics in its employ, so far as the same may be applicable to work under this tariff.

M. Notices.

Notices by the Company or the Customer shall be in writing, mailed or delivered to the respective addresses set forth in the Service Agreement. Either party may change its address by written notice to the other.

N. Term.

Once initiated, service under this tariff shall continue until terminated by either party giving to the other at least seven years' written notice of termination directed to the end of a calendar month.

A Customer that seeks to terminate service without providing the notice required under this tariff and its service agreement and that has not otherwise agreed to a settlement of its early termination costs may exercise an option to terminate service under this tariff early by giving the

Company thirty days' written notice directed to the end of a calendar month and paying the Contract Termination Charge applicable under Schedule II-C of this tariff. The Contract Termination Charge shall be payable in equal monthly installments of principal and interest, the first payment to be made within 30 days after the date of termination of service ("Early Termination Date"), over the remaining term of the Customer's notice period (or such shorter term, or in a single payment, as agreed by the Company and the Customer). The Customer's payments shall include carrying charges on the unpaid amount of the Contract Termination Charge at the interest rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. 35.19a) effective on the Early Termination Date and compounded monthly. The Company reserves the right to require the Customer to provide security in a form appropriate to the Company and consistent with commercial practices to protect the Company against the risk of non-payment. This paragraph shall not apply to Customers that have entered into settlement agreements with the Company allowing early termination of service under this tariff and establishing the recovery of contract termination charges. The Company at its discretion may waive the thirty days' notice provision under this paragraph.

O. Successors and assigns.

The executed service agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties.

NEW ENGLAND POWER COMPANY

Schedule II-A

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NEW ENGLAND POWER COMPANY

Schedule II-B

NEW ENGLAND POWER COMPANY
Primary Service for Resale
Rate W-95(N)

Demand Charge:	$17.17 per month for each kilowatt of Demand.
Energy Charge:	21.83 mills ($0.02183) for each kilowatt-hour of electricity delivered, except for kilowatt-hours of electricity delivered under Service for Resale to Interruptible Customers, Schedule III-C.
Interruptible Service: Charge	For each kilowatt-hour delivered in any hour pursuant to Schedule III-C, the amount specified for that hour by the Company pursuant to Paragraph C of Schedule III-C
Fuel and Purchased Economic Power Adjustment Clause:	For any month for which the Cost of Fuel is greater or less than 14.0000 mills per kilowatt-hour, the Energy Charge shall be increased or decreased respectively by the applicable fuel adjustment rate per kilowatt-hour delivered, which rate shall be equal to the difference of:

$$\frac{Fm}{Sm} - \frac{Fb}{Sb}$$

Where F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and "S" is the kilowatt-hour sales in the base and current periods, all as defined in Section 35.14 of the Regulations under the Federal Power Act as provided in Order No. 352 issued December 7, 1983 in Docket No. RM83-62-000. F shall also include expenses associated with purchases of electricity from alternate energy suppliers, provided however that payments from such suppliers due to their failure to perform or pursuant to contractual security provisions shall be credited to F above. F shall be credited with the revenues from sales for resale to interruptible customers pursuant to Schedule III-C and such sales shall be excluded from S.

As a signatory to the NEPOOL Agreement, dated as of September 1, 1971, as amended, the Company's reserve capacity criteria is determined as a part of the NEPOOL reserve requirement. This type of interconnected pool operation avoids the need for member companies to individually determine reserve capacity criteria, while preserving individual company integrity through the basic NEPOOL Agreement. Each member utility's commitment to the Pool's requirements is assured by a monthly assessment of each members "Capability Responsibility", as defined in the NEPOOL Agreement. See also the NEPOOL Agreement, FERC Rate Schedule No. 210. In determining whether a purchase is a reliability purchase, the Company will use its then-applicable NEPOOL reserve requirement, regardless of whether the selling utility is a member of NEPOOL. In the event that a short term operating reserve purchase is made by NEPOOL and an assessable share is billed to NEP, NEP will include in this clause only the cost of fuel associated with such purchase. Part of the costs in evaluating the interchange with NEPEX (the NEPOOL dispatching agency) may initially be estimated. All energy savings shares that are created in the NEPEX dispatch are reflected in fuel costs. The value of the estimated costs will be combined with the value of the actual costs for the billing month to determine the monthly fuel clause factor. Any difference between the actual and estimated data for a billing month will be reflected in cost data utilized in the calculation for the succeeding month.

Notwithstanding the above, whenever the foregoing determination would be affected by energy produced from generating units under construction as they undergo operational tests prior to their in service dates, the components of F shall be adjusted so that its value is the same as it would have been if such test energy were not available. Such adjustment to F in the formula shall also recognize that current wholesale customers have paid a part of the cost of generating units under construction through demand charges reflecting CWIP in rate base; therefore, a credit to F shall be applied equal to the differential between the cost of test energy and the displaced cost of fuel in the ratio that demand contributions for such units bear to the carrying cost of such units.

In addition to the foregoing, F shall also include fifty percent (50%) of all natural gas transportation demand charges incurred for the period beginning November 1, 1991 and ending on the sooner to occur of January 1, 1996 or the conclusion of the construction period for the Manchester Street Station repowering project, provided, however, that revenues received from third parties related to their use of NEP's pipeline capacity during the foregoing period shall be credited to F above. Thereafter, all natural gas transportation demand charges incurred shall be included in F above.

Once each calendar year, NEP shall reconcile the total incremental fuel costs of all short-term unit sales transactions, and sales pursuant to Schedule III-C, to fuel revenue from these transactions. If the total incremental fuel cost exceeds the fuel revenue, F shall be credited with the differential. The reconciliations shall be done in accordance with the procedures set forth in Dockets 92-372-000 <u>et al.</u> (unit power contracts) and Docket No. 94-1056-000 (Schedule III-C sales).

In accordance with a Surcharge Compliance Filing Settlement Agreement filed in Docket Nos. ER88-630-000, <u>et</u> <u>al.</u>, a monthly charge for fuel expense underrecovery will be assessed all Customers except Massachusetts Electric Company, as shown at Appendix C to that Settlement Agreement. The foregoing charge will become effective as approved by the Commission and will continue thereafter for a period of ten (10) years, provided that if any of these Customers terminates service from NEP prior to the conclusion of the amortization period, that Customer shall pay its remaining unamortized fuel expense upon the date it terminates service. The monthly charge will be: Narragansett Electric - $48,889, Granite State - $6,499, Groveland - $225, Merrimac - $196, Littleton - $535, Norwood - $3,128, N.H. Elec. Coop - $66, GMP - $52, and Ft. Devens - $540.

In accordance with the settlement of Docket No. FA91-53-000, F shall also include the 1.5% NEPEX differential billed to NEP by Central Maine Power for the use of low sulphur oil in the Wyman Units 1, 2, and 3 when Wyman 4 is operating.

Standard Delivery Point: For purposes of this Tariff, the “Standard Delivery Point” shall be considered to be that point on the integrated generating and transmission system of the Company that first follows one transformation from the power supply system or, by agreement of the parties, a point in close proximity thereto.

Metering Adjustments: Where delivery is metered at the Company’s supply line voltage, in no case less than 69,000 volts, thereby saving the Company transformer losses then, before determining the number of kilowatts and kilowatt-hours to be billed under the preceding provisions, there shall be deducted from the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one percent (1.0%) of such registrations. Where delivery is metered at the sub-transmission voltage, or at the low side terminals of the transformation from the sub-transmission to the distribution of the customer, and not at the low side terminals of the transformation from the Company's supply line, there shall be added to the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one and one half percent (1.5%) of such registrations.

Transformer Ownership Credit:

If delivery is made at the Company's supply line voltage, not less than 69,000 volts, and the Company is saved the cost of installing any transformer and associated equipment there will be allowed a credit of thirty cents ($0.30) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. In accordance with a Settlement Agreement in Docket Nos. ER91-565-000, et al., the credit applicable to the Town of Norwood will be twenty-one cents ($0.21) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. The foregoing credits, as applicable, shall be computed after the applicable Metering Adjustments.

Credit for EPRI Contributions:

A credit of six cents ($0.06) per kilowatt of the demand component will be allowed to all customers served under this schedule with the exception of the Company's affiliated customers (Massachusetts Electric Company, Narragansett Electric Company and Granite State Electric Company) in order to reflect the Company's commitment to research support of the Electric Power Research Institute (EPRI) unless a customer notifies the Company in writing that it desires to contribute through the Company's commitment, in which event this credit shall not apply to such Customer. In accordance with a Settlement Agreement in Docket Nos. ER91-565, et al., the credit applicable to the Town of Norwood will be nine cents ($0.09) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. These credits shall be computed after the application of any applicable Metering Adjustments and at the point of delivery which enters into the computation of the Customer's Demand for the month in question.

Norwood Yankee: Surcharge:	In accordance with the terms of the W-12 Settlement Amendment dated December 17, 1992 in Docket No. ER90-525 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with that settlement.
Norwood Seabrook 1 Amortization Surcharge:	In accordance with the terms of the W-95(N) Settlement dated June 30, 1995 in Docket No. ER95-267 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with section 2.2(b) of that settlement.

The Company reserves the right to amend the foregoing rate in the manner set forth in its General Terms and Conditions governing primary service for resale in Schedule I.

Effective Date: July 12, 1995

NEW ENGLAND POWER COMPANY

Primary Service for Resale

DETERMINATION OF CONTRACT TERMINATION CHARGE
UNDER EARLY TERMINATION PROVISION

A. Applicability

The terms and conditions of this Schedule II-C are applicable to any eligible all-requirements wholesale customer ("Customer") of New England Power Company ("Company") under this tariff which elects the early termination option under Schedule I, Section N of this tariff.

B. Determination of Contract Termination Charge

If a Customer exercises the early termination option under Schedule I, Section N, paragraph 2, of this tariff, the Customer shall pay the Company a Contract Termination Charge ("CTC") as determined under this schedule. The CTC shall be determined as follows:

$$CTC = (R - M) \times L$$

where:

R	=	the Customer's Annual Average Revenue, as determined in Section 1 below;
M	=	the Estimated Market Value of the Customer's released capacity and associated energy, as determined under Section 2 below;
L	=	the Length of Obligation in years, as determined under Section 3 below;

Payment of the CTC by the Customer shall be in accordance with Schedule I, Section N, paragraph 2, of this tariff.

The CRC shall be determined on a net present value basis, with the difference between R and M discounted to the Early Termination Date as defined in Section 3 below. The discount rate used shall equal the rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. § 35.19a) effective on the Early Termination Date.

In no event shall the CTC exceed the amount determined under section 4 below.

1. R – Average Annual Revenue

The Customer's Annual Average Revenue shall equal the Total Revenue minus the Transmission Revenue.

a. *Total Revenue* shall equal the annual average of revenues received by the Company from the Customer over three years under the presently effective rates as shown on Schedule II-A and Schedule II-B of this tariff. The three-year period shall be the 36 months immediately prior to the Early Termination Date as specified by the Customer under the second paragraph of Schedule I, Section N of this tariff. In the event that the rates paid by the Customer under Schedule II-A or Schedule II-B of this tariff have changed during the three-year period, Total Revenue shall be determined using the Customer's revenue for the 12 months immediately prior to the Early Termination Date. The Company at its discretion may use estimates of the Customer's billing units for determining Total Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date. The calculation of Total Revenue shall include credits pursuant to Schedule III-D of this tariff as well as all credits and surcharges applicable to the Customer under the Customer's Service Agreement with the Company under this tariff, with the exception of credits associated with Integrated Facilities arrangements under Schedule III-B of this tariff and any credits associated with the Company's reimbursement of the Customer's payments to third parties for transmission service.

b. *Transmission Revenue* shall equal the sum of: (i) the annual average of revenues the Company credited to the Customer with respect to payments made by the Customer to third parties for transmission service pursuant to any applicable provision of the service agreement between the Company and the Customer; or (ii) if the service agreement does not provide for such credits, the annual average of revenues the Company would have received from the Customer using the presently effective rates under the Company's Open Access Transmission Tariff, FERC Electric Tariff Original Volume No. 9 ("Tariff No. 9"); and (iii) the annual average of payments made by the Company to the New England Power Pool ("NEPOOL") for transmission service on the Customer's behalf under NEPOOL's Open Access Transmission Tariff, all as determined during the period over which the Total Revenue is determined. The Company at its discretion may use estimates of the Customer's billing units for determining Transmission Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date.

2. M – Estimated Market Value

The Estimated Market Value shall equal the annual average of the Market Price Estimate for each year of the Length of Obligation (as determined pursuant to Section 3 below) multiplied by the Customer's Released Load.

a. *Market Price Estimate* shall equal the per kilowatt-hour amount set forth in the Table below, as in effect on the Early Termination Date, as applicable to each year during the Length of Obligation. The Market Price Estimate shall include both a capacity-related and energy-related component.

Year	Capacity (¢/kWh)	Energy (¢/kWh)	Total (¢/kWh)
1998	1.10	2.71	3.81
1999	1.22	2.64	3.86
2000	1.22	2.66	3.88
2001	1.25	2.61	3.86
2002	1.31	2.63	3.94
2003	1.34	2.71	4.05
2004	1.40	2.72	4.12
2005	1.44	2.77	4.21
2006	1.47	2.86	4.33
2007	1.53	2.95	4.48
2008 forward	prices for 2007 escalated at 2% annually		

b. *Released Load* shall equal the annual average of the Customer's kilowatt-hour purchases from the Company for the period over which Total Revenue is determined. The Company at its discretion may use estimates of the Customer's kilowatt-hour purchases for determining Released Load, such estimates to be reconciled to actual purchases within six months after the Early Termination Date.

3. <u>L – Length of Obligation</u>

The Length of Obligation shall equal the time period between the Early Termination Date and the Regular Termination Date.

a. *Early Termination Date* shall be as determined under Schedule I, Section N, paragraph 2 of this tariff

b. *Regular Termination Date* shall be the date at which the Company or the Customer could have unilaterally terminated service under Schedule I, Section N, paragraph 1 of this tariff and any applicable provisions of the Customer's Service Agreement with the Company under this tariff.

4. <u>Maximum Contract Termination Charge</u>

In no event shall the difference between R and M (as determined in Sections 1 and 2 above) exceed the Customer's annual contribution to the Company's fixed power supply costs under this tariff. The Customer's annual contribution to the company's fixed power supply costs shall equal its Total Revenue minus Transmission Revenue minus the Company's Average Fuel Costs. Average Fuel Costs shall equal the annual average of revenues the Company recovered for its Cost of Fuel as defined in Schedule II-A of this tariff multiplied by the Customer's monthly kilowatt-hour purchases during the period over which Total Revenue is determined in Section 1 above.

NEW ENGLAND POWER COMPANY

Schedule III-A

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NEW ENGLAND POWER COMPANY

Primary Service for Resale

TERMS AND CONDITIONS~~MONS~~

governing

ALL-REQUIREMENTS SERVICE — INTEGRATED FACILITI~~CI~~ES

Schedule III-B

A. Applicability

The terms and conditions set forth herein shall apply when the Service Agreement is between the Company and a Customer which is affiliated with the New England Power Company, and specifies All-Requirements Service — Integrated Facilities.

B. Integrated facilities: Obligations of the parties.

Recognizing that the generation and transmission facilities owned by the Company and the Customer are physically interconnected and can be operated to achieve maximum economy through integrated operation, the Customer and the Company agree as follows:

1. The Customer will operate and maintain its generating and transmission facilities in accordance with standards fixed from time to time by the Company, and will make available to the Company the full capacity of such facilities to meet the load of the integrated generating and transmission system (consisting of the generating and transmission facilities owned by the Company and affiliated companies of the New England Power Company). The Company and the Customer may agree to exclude from the facilities made available as aforesaid any facilities deemed not to be necessary or feasible for integration, and such excluded facilities shall not be considered part of the integrated generating and transmission system as defined above.

2. The generating and transmission facilities of the Customer made available to the Company under paragraph 1 shall be subject to dispatch by the Company to meet the load of the integrated generating and transmission system, and the output of the Customer's generating units so dispatched shall be deemed to be for the account of the Company. The Customer will conform to maintenance schedules fixed by the Company to ensure maximum availability of capacity.

3. The Company and the customers whose facilities constitute a part of the integrated generating and transmission system will plan jointly for the future requirements of such system. The Customer agrees to make additions to and retirements of its generating and transmission facilities in accordance with schedules fixed from time to time by the Company.

4. In consideration of the foregoing, the Company assumes responsibility for the supply of the electrical requirements of the Customer from the integrated generating and transmission system, including transmission losses over such system, and agrees to credit the Customer for the use of its generating and transmission facilities, in accordance with the following provisions:

   a. The Company agrees to sell and the Customer agrees to buy, at the Company's effective rate for primary service for resale, the Customer's entire requirements of electricity for its own use and for resale within the Districts described in the Service Agreement, with the following exceptions: (1) electricity purchased by the Customer from commercial and industrial establishments located within any District of the Customer's service area and specified in the Service Agreement, (2) electricity purchased by the Customer under convenience contracts for the supply of electricity to borderline customers, and (3) such other exceptions as may be mutually agreed upon between the parties and set forth in the Service Agreement.

   b. For Customer-owned Transmission Plant, the Company will credit each monthly bill rendered to the Customer using the calculation shown below based on the previous month's cost data from Customer's official books and records. Capitalized terms used in this calculation will have the following definitions:

      1. Gross Transmission Plant Allocation Factor shall equal the ratio of Customer's Total Investment in Transmission Plant to Total Plant in Service, excluding General Plant.

      2. PTF Allocation Factor shall equal the ratio of PTF Transmission Plant to Transmission Plant.

      3. PTF-RSP Allocation Factor shall equal the ratio of PTF-RSP Transmission Plant to Transmission Plant.

      4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct electric wages and salaries from Customer to Customer's total electric direct wages and salaries and excluding electric administrative and general wages and salaries.

5. Administrative and General Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 920-935, less Post Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, plus the FERC-accepted Post Employment Benefit Other than Pensions identified in each Customer's Service Agreement or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

6. Amortization of Investment Tax Credits shall equal Customer's electric credits as recorded in FERC Account No. 411.4.

7. Amortization of Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account No. 428.1.

8. Depreciation Expense for Transmission Plant shall equal Customer's electric transmission plant related depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement.

9. General Plant shall equal Customer's electric gross general plant balance as recorded in FERC Account Nos. 389-399.

10. General Plant Depreciation Expense shall equal Customer's electric general plant related depreciation expenses as recorded in FERC Account No. 403.

11. General Plant Depreciation Reserve shall equal Customer's electric general plant depreciation reserve balance as recorded in FERC Account No. 108.

12. Municipal Tax Expenses shall equal Customer's electric transmission-related municipal tax expense as recorded in FERC Account No. 408.1.

13. Payroll Taxes shall equal those electric payroll tax expenses as recorded in Customer's FERC Account Nos. 408.1.

14. Land Held for Future Use shall equal the Customer's electric transmission-related balance for Land in FERC Account No. 105.

15. Prepayments shall equal Customer's electric prepayment balance as recorded in FERC Account No. 165.

16. PTF-RSP Transmission Plant shall equal any PTF Transmission

Plant as defined below and approved as part of the ISO-NE Regional System Plan.

17. PTF Transmission Plant shall equal electric transmission plant as defined in Section II.49 of the ISO-NE OATT and determined in accordance with Appendix A of Attachment F Implementation Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

18. Total Accumulated Deferred Income Taxes shall equal the net of Customer's electric deferred tax balance as recorded in FERC Account Nos. 281-283 and Customer's electric deferred tax balance as recorded in FERC Account No. 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes <u>and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities</u>.

19. Total Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account 189.

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

21. Total Transmission Depreciation Reserve shall equal Customer's electric transmission plant related depreciation reserve balance as recorded in FERC Account 108.

22. Transmission Operation and Maintenance Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 560-564 and 566-573 less any expenses recorded in FERC Account 561.4.

23. Transmission Plant shall equal Customer's electric gross plant balance as recorded in FERC Account Nos. 350-359.

24. Transmission Plant Materials and Supplies shall equal Customer's electric materials and supplies balance as recorded in FERC Account No. 154

25. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided which is not specifically identified under any other section contained herein.

In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

Calculation of Transmission Revenue Requirements

The monthly Transmission Revenue Requirement shall equal the sum of Customer's (A) Return and Associated Income Taxes (including the Incremental Returns for PTF-RSP and PTF Investment), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Distribution, Credit, (J) Transmission Related Taxes and Fees Charge, (K) Billing Adjustments, and (L) Annual True-Up Adjustment. The Incremental Return and Associated Income Taxes for PTF-RSP and PTF Investments shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of each of the Transmission Investment Base (PTF-RSP, PTF and Non-PTF, respectively) and the Cost of Capital Rates applicable to each.

1. Transmission Investment Base

(a) Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(i) PTF-RSP Investment Base will be the monthly balances of PTF-RSP Transmission Plant, less the sum of (d)

Transmission Related Depreciation Reserve and (e) Transmission Related Accumulated Deferred Income Taxes, multiplied by the PTF-RSP Allocation Factor.

(ii) PTF Transmission Investment Base will be the monthly balances of PTF Transmission Plant, less PTF-RSP Investment Base, plus the product of: PTF Allocation Factor multiplied by the sum of the [(b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Income Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital].

(iii) Non-PTF Transmission Investment Base shall equal Total Transmission Investment Base less PTF-RSP Investment Base less PTF Investment Base.

(b) Transmission Related General Plant shall equal Customer's balance of investment in electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Land Held for Future Use shall equal Customer's balance of electric Transmission-related Land Held for Future Use.

(d) Transmission Related Construction Work In Progress shall equal the portion of Customer's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal Customer's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal Customer's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Gross Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal

Customer's electric balance of Total Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal Customer's electric balance of prepayments multiplied by the Gross Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal Customer's electric balance of Transmission Plant Materials and Supplies, multiplied by the Gross Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Customer's Transmission Operation and Maintenance Expense (less FERC Account 565: Transmission of Electricity by Others) and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will incorporate Customer's imputed capital structure, Customer's actual cost of long-term debt and preferred equity, and approved ROEs for Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively), plus Federal Income Tax.

(a) The Weighted Costs of Capital will be calculated for each of the Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively) based upon the imputed capital structure for Customer in place in accordance with Rhode Island Docket Nos. 2930 and 3617 and will equal the sum of (i), (ii), and each ROE applied in item (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45%.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Customer's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5%.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs applicable to the corresponding investments below and the Customer's imputed common equity capitalization ratio of 50%.:

12.64% - Post-2003 to pre-2009 PTF transmission plant investment included in the Regional System Plan approved by ISO-NE.

11.64% - The remaining PTF transmission plan investment.

11.14% - The remaining transmission plant investment.

As per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679. To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

(b) Federal Income Tax applied shall equal

$$(PS + ROE) \quad X \quad \frac{\text{Federal Income Tax Rate}}{(1\text{- Federal Income Tax Rate})}$$

where PS is the Preferred Stock Component and ROE is the return on equity component, each as determined in Sections 2.(a)(ii) and for the applied ROEs set forth in 2.(a)(iii) above.

B. Transmission Depreciation Expense shall equal Customer's electric Depreciation Expense for Transmission Plant, plus an allocation of electric General Plant Depreciation Expense calculated by multiplying electric General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Customer's electric Amortization of Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Customer's electric Amortization of Investment Tax Credits multiplied by the Gross Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal Customer's transmission-related electric municipal tax expense.

F. Transmission Related Payroll Tax Expense shall equal Customer's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Customer's total electric Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of Customer's electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

I. Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this section, including, but not limited to, expenses incurred by the Customer related to third party independent audits conducted at the request of any governmental authority, and any other fee or assessment which is not specifically identified under any other section contained herein. Such costs will be separately identified and included in item H — Administrative and General Expense, above.

K. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.

L. Annual True-Up Adjustment

1. NEP shall submit an annual informational filing with the FERC <u>with copies to state commissions and attorneys general in the state of any affected Customer</u> reconciling monthly billings to Customer under this formula to data supplied from Customer's Quarterly FERC Form 1 (the "Annual True- up"). The Annual True-up will be completed no later than (3) months after Customer issues its final 4th Quarter FERC Form 1 for the calendar year which the Annual True-up relates (the "Service Year"). The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form l's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all

balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

2. The difference, if any, between the monthly actual costs invoiced to Customer during the Service Year and the annual revenue requirement based on actual FERC Form 1 data shall be reflected as an adjustment to the monthly revenue requirement calculation for the month following the month in which the Annual True-Up report is issued (the "Annual True-up Adjustment").

3. If the recalculation of costs for the Service Year using FERC Form 1 data exceeds the monthly billed amounts for the Service Year, the Annual True-up Adjustment will be an additional credit to Customer. If the monthly billed amounts for the Service Year exceed the recalculation of costs using FERC Form 1, the Annual True-up Adjustment will be a reduction to the credit to Customer. The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the Commission's regulations 18 C.F.R §35.19a.

4. Any changes to the data inputs, including but not limited to revisions to Customer's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-up, or as a result of the procedures set forth herein not otherwise captured as part of ongoing Billing Adjustments, shall be incorporated into the formula rate and the charges produced by the formula rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual True-up for the next effective rate period.

5. In any proceeding before the FERC concerning the Annual True-up, the Company shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

M. Five-Year Forecast

The Company's annual informational filing will also provide a report containing a five year forecast of anticipated transmission capital expenditures by the Company and its Customers taking service under this Tariff that will, upon completion of projects, be included in transmission rates. The forecast will also include the estimated retail rate impacts for each of the Company's respective Customers under this Schedule III-B.

N. Audit Provisions

1. There will be an "Audit Period" that will extend from the date the informational filing is filed with FERC through December 31 of the year following the Service Year. At any time during the Audit Period, a Customer shall have the right to request an audit or conduct an inspection of the actual data used in the Annual True-Up and any and all transmission charges or credits billed by Company during the Service Year. Subject to the limitation that the Attorneys General of Massachusetts and Rhode Island do not make or receive transmission payments or refunds, they shall have the same procedural rights under this Section as a Customer. Company shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel as prescribed by FERC. Company is not obligated to disclose privileged information or information protected by the attorney work product doctrine. Company shall exercise all commercially reasonable efforts to provide Customer, within 10 business days, such additional information as Customer may reasonably request. To the extent requested, Company shall meet with any Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up or any other information related to Customer billing under this Tariff during the Service Year. During the Audit Period any Customer may request that Company adjust the Annual True-up Adjustment and/or Customer bills rendered during the Service Year. Any adjustment that Company agrees to make may be reflected in the next month following such adjustment. Upon request of any Customer during the Audit Period, Company shall engage a third party independent auditor (the "Auditing Entity") through the process described in Paragraph 4, below. The Auditing Entity shall certify that the development, accuracy and application of data, is in accordance with the provisions of this Tariff. The Auditing Entity shall provide a Certified Public Accountant's attestation setting forth such certification ("CPA Attestation").

2. In addition to the CPA Attestation, the Auditing Entity will provide an audit report that will specify the audit process and procedures; identify the individual auditors and their functions; and include all copies of all written communications with Company personnel, summaries of all other communications related to the audit, descriptions of all data analysis techniques used, findings and recommendations. Also, the Auditing Entity shall make available all workpapers and other documentation and materials that support the CPA Attestation.

3. Company shall engage the Auditing Entity to perform the CPA Attestation duties through a competitive bidding process, evaluating each bidder

according to cost, experience, competency and familiarity with the industry and the regulatory environment. The requesting Customer(s) shall have the right to approve the content of the Request for Proposal and Company's selection of the auditing entity, which approval shall not be unreasonably withheld. If necessary, and after good faith efforts have not resulted in the Company's obtaining an Auditing Entity to provide the CPA Attestation pursuant to this Paragraph 4, the requesting Customer(s) and the Company agree to negotiate in good faith the scope of work that may be needed to provide a CPA Attestation and to accommodate the American Institute of Certified Public Accountants Code of Professional Conduct.

4. In the event an independent audit is performed with respect to a Service Year and the Company determines that the Annual True-Up is incorrect, the Annual True-Up required by Paragraph L of this Tariff may be subsequently adjusted pursuant to the provisions of this Tariff.

5. The reasonable and prudent cost of the Auditing Entity's services and Company's reasonable and prudent costs of engaging the Auditing Entity and providing information to the Auditing Entity and the Customer shall be included as part of the transmission costs charged to the Customers under this Tariff.

Formula rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission.

application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expense under the formula rate shall not open review of other components of the formula rate.

Calculation of Primary Distribution Revenue Requirements

For Customer-owned distribution facilities utilized by the Company for purposes of providing wholesale transmission service, effective as of the June billing month of each year , the Company will credit each monthly bill rendered to the Customer with one-twelfth of the annual costs determined by multiplying the sum of the applicable Customer's: (i) Distribution Plant Assets; (ii) Shared Substation Assets, and; (iii) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Primary Distribution Carrying Charge based upon previous calendar year data. The Primary Distribution Carrying Charge shall be calculated as follows for the applicable Customer:

I. The Primary Distribution System Carrying Charge shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit, divided by Total Primary Distribution Plant.

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

1. Primary Investment Base will be (a) Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Primary Materials and Supplies, plus (h) Primary Related Prepayments, plus (i) Primary Related Cash Working Capital.

a) Primary Distribution Plant shall equal the Customer's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Allocation Study.

b) Primary Related General Plant shall equal the Customer's Investment in General Plant excluding investment in specific buildings and facilities allocated to Company, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total Customer's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

c) Primary Plant Held for Future Use shall equal the Customer's Account

105, multiplied by the Primary Land Allocation Factor from the Distribution Allocation Study.

d) Primary Depreciation Reserve shall equal the Customer's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above,

e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

g) Primary Materials and Supplies shall equal the Customer's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

h) Primary Related Prepayments shall equal the Customer's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

i) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

2. Cost of Capital Rate will equal (a) the Customer's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (e) 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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of the Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the Customer's preferred stock then outstanding and the Imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE), shall be the product of the allowed ROEs shall be 11.14% as per FERC's Order on Rehearing Issued on March 24, 2008-in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679.[1] To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \times FT}{1-FT}$$

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (l)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (1)(A)(2)(b) above.

B. Primary Depreciation Expense shall equal Customer's electric distribution-related depreciation expense as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(l)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the Customer's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the Customer's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(I)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the Customer's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Allocation Study.

G. Primary Related Administrative and General Expenses shall equal the Customer's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

H. Primary Related Revenue Credit shall equal Customer's Other Operating Revenues excluding any revenues from network distribution transactions, multiplied by the Primary O&M Allocation Factor as defined in (I)(A)(1)(b).

For Company-owned facilities utilized by the Customer for purposes of providing retail distribution service, effective as of the June billing month of each year, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual costs determined by multiplying the sum of the Company's: (i) Transmission Assets~~rs~~ ~~(13.8 and 23 kV)~~ (ii) Distribution Plant Assets; (iii) Shared Substation Assets, and; (iv) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Annual Facilities Carrying Charge for Transmission Facilities ~~set forth in Attachment DAF of Schedule 21-NEP to the ISO New England Asset Open Access Transmission Tariff or any successor schedule.~~ based upon previous calendar year data. In addition, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual cost for pole and tower attachments. The Annual Facilities Charge for Transmission Facilities shall be calculated as follows:

1. The Annual Facilities Carrying Charge for Transmission Facilities shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D)Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Operation and Maintenance Expense, and (G) Transmission Related Administrative and General Expenses, divided by Total Transmission Plant.

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

1. **Transmission Investment Base** will be (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Income Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Materials and Supplies, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Related Prepayments, plus (k) Transmission Related Cash Working Capital.

a) **Transmission Plant** shall equal NEP's balance of Total Investment in Transmission Plant in FERC Accounts 350 – 359, plus NEP's Total Investment in Distribution Plant in FERC Accounts 360-369 excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases).

b) **Transmission Related General Plant** shall equal NEP's balance of investment in General Plant in FERC Accounts 389 to 399 excluding General Plant related to NEP's generation facilities.

c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC account 105 excluding generation-related plant held for future use.

d) **Transmission Related Construction Work in Progress** shall equal the portion of NEP's investment in Transmission related projects as recorded in FERC Account 107 consistent with Commission Orders.

e) **Transmission Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve in FERC Account 108, excluding any generation-related depreciation reserve.

f) **Transmission Related Accumulated Deferred Income Taxes** shall equal the net of NEP's Total Accumulated Deferred Income Taxes in FERC Accounts 281-283 and FERC Account 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities. and any Accumulated Deferred Taxes associated with non-utility assets or generation facilities.

g) **Transmission Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt in FERC Account 189.

h) **Transmission Related Materials and Supplies** shall equal NEP's balance of Materials and Supplies in FERC Account 154.

i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission Orders.

j) **Transmission Related Prepayments** shall equal NEP's balance of prepayments in FERC Account 165 excluding any prepayments related to NEP's ongoing generation-related activities.

k) **Transmission Related Cash Working Capital** shall be 12.5% allowance (45 days/360) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. **Cost of Capital Rate**

The Cost of Capital Rate shall equal (a) NEP'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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of NEP's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE) shall be the product of 11.14% as per FERC's Order on Rehearing issued on March 24,

2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and NEP's imputed common equity capitalization ratio of 50%, To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to the filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \times FT}{1-FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)()2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and the Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Transmission Related Depreciation Expense** shall equal the Depreciation Expense in FERC Account 403 associated with Transmission Plant, Transmission Related General Plant and Transmission Plant Held for Future Use as described in Sections (I)(A)(1)(a), (b) and (c), less the amortization of AFUDC Regulatory Liability as recorded in FERC Account 407.3.

C. **Transmission Related Amortization of Loss on Reacquired Debt** shall equal NEP's amortization of the balance on Loss on Reacquired Debt recorded in FERC Account 428.1.

D. **Transmission Related Amortization of Investment Tax Credits** shall equal the amortization of Investment Tax Credits recorded in FERC Account 411.4, excluding any ITC credits specifically identified as generation-related.

E. **Transmission Related Municipal Tax Expense** shall equal NEP's total municipal tax expense recorded in FERC Account 408.1 excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

F. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems.

G. **Transmission Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses recorded in FERC Accounts 920-935, less production-related Administrative and General Expenses associated with joint-owned production units, plus Payroll Taxes.

The Company's rate for tower attachments is $49.28 per tower. The Company's rate for pole attachments is $253.27 per pole. The annual cost for the Customer to attach to the Company's towers and poles will be the product of the respective rate multiplied by the number of respective attachments as specified in the Customer's Service Agreement.

The Customer shall afford to the Company the opportunity at any time to make such reasonable examination of the Customer's books and records as the Company may request for the purpose of verifying the basis for calculation of the foregoing monthly credits.

The foregoing credits shall be reviewed annually and upon substantial addition, modification or retirement of the Customer's generating and transmission facilities or other substantial change in circumstances, any changes therein shall be reflected in a revised Service Agreement.

C.

If the Service Agreement is amended by mutual consent of the parties, the terms of the agreement as so amended shall be applicable to the Customer's service on and after the effective date specified therein. If no such amendment has been executed prior to the date specified in the Customer's notice, the Customer may at its election terminate the Service Agreement forthwith or upon such date within the following twelve months as it may specify to the Company in writing.

D. Amendments.

The Company reserves the right to amend the foregoing terms and conditions in the manner set forth in its General Terms and Conditions governing primary service for resale.

NEW ENGLAND POWER COMPANY

Schedule III-C

THIS SECTION INTENTIONALLY LEFT BLANK

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

FORM OF SERVICE AGREEMENT

Dated:

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

20 Turnpike Road
Westborough, Massachusetts 01581

and

(the "Customer")

1. Scope of Service Agreement. The Company agrees to sell and transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I	- General Terms and Conditions
Schedule II	- Rate Provisions
Schedule III	- Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By ______________________________
Vice-President

APPENDIX A

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:

2. Name of District:

3. Service Under:

4. Electric Utilities Served by the Customer
as of the date of the Service Agreement:
(Schedule I - Paragraph D)

5. Electricity Purchased from Commercial
and Industrial Establishments by the
Customer as of the date of the Service
Agreement:
(Schedule I - Paragraph D)

6. Variations from Standard Delivery and
Metering:
(Schedule I - Paragraph G, 5)

7. Entitlements:

   A. On Customer System
      (Schedule III-C - Paragraph C.2.(a))

   B. Off Customer System
      (Schedule III-C - Paragraph C.2.(b))

8. Customer Generation excluded from

Firm Capacity Calculation:

(Schedule III-C - Paragraph C.3.c)

9. Firm Capacity:

(Schedule III-C - Paragraph C.3.c)

10. Integrated Generating, Transmission and Facilities Credits Payable by Company:

(Schedule III-B - Paragraph B.4.b)

11. Primary Service for Resale:

Delivery Points	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments

12. Minimum Demand KW: None

13. Minimum Term: None

14. Transmission Service for Partial Requirements Customers:

Transmission Delivery Point(s)	KV (Nominal)	Subtransmission Delivery Point(s)	KV (Nominal)

SERVICE AGREEMENT

Between

NEW ENGLAND POWER COMPANY

And

MASSACHUSETTS ELECTRIC COMPANY

And

NANTUCKET ELECTRIC COMPANY

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

Dated: February 15, 1974

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

and

MASSACHUSETTS ELECTRIC COMPANY and
NANTUCKET ELECTRIC COMPANY
Massachusetts corporations (the "Customer")

1. Scope of Service Agreement. The Company agrees to transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I - General Terms and Conditions

Schedule II - Rate Provisions

Schedule III - Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

NONE

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By: ______________________________

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY

By: ______________________________

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:	Massachusetts Electric Company, Nantucket Electric Company
2. Name of District:	Baystate West, Baystate South, and North and Granite
3. Service Under:	Schedules III-B of the Tariff and Settlements accepted by the Commission in Docket Nos. ER97-678-000, ~~and~~ ER97-2800-000, and ER10-523-000.
4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	The Naragansett Electric Company, Western Mass Electric Company Hingham Municipal Lighting Plant, Boston Edison
5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Not Applicable. Mass Electric no longer takes generation service under Tariff No. 1. Contract Termination Charge provided pursuant to Contract Termination Charge Amendment
6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)	Not applicable
7. Entitlements:	
A. On Customer System (Schedule III-C Paragraph C.2.(a))	None
B. Off Customer System (Schedule III-C Paragraph C.2.(b))	None
8. Customer Generation excluded from Firm Capacity Calculation: (Schedule III-C – Paragraph C.3.c)	None
9. Firm Capacity: (Schedule III-C – Paragraph C.3.c)	None

10. Integrated Generating, Transmission and Facilities Credits - Schedule III-B: Company and Customer acknowledge that the formula rates and Company's billings to Customer under Schedule III-B shall be subject to and shall comply with the terms and conditions of the Uncontested Settlement Agreement approved by the FERC in ~~Docket No. ER07-694-000 (Settlement). *New England Power Company*, 125 FERC ¶ 61,298 (2008)~~FERC Docket No. ER10-523-000 (Settlement), *New England Power Company*, [ ]. ~~In accordance with the Settlement, Company's billings to Customer will be subject to an Annual True-Up to be reported to FERC in an informational filing, the Annual True-Ups shall be subject to audits upon request of the Parties to the Settlement and Company shall provide an annual informational filing showing a 5-year forecast of Customer's transmission capital additions, including an estimate of the impact that such additions would have on retail customers.~~

(Schedule III-B - Paragraph B.4.b)

Payable by Company:

Customer Distribution Plant Assets Serving Wholesale Transmission Function:	Attachment 1	$4, 741, 264
Customer Shared Substation Assets:	Attachment 2	$2,365,249
Customer Buildings and Facilities	Attachment 3	~~$3,090,344~~$2,141,768

Payable by Customer:

Company Transmission Assets (13.8 and 23kV)	Attachment 4	$4, 075,372
Company Distribution Plant Assets	Attachment 5	$292,975
Company Shared Substation Assets:	Attachment 2	$8,190,969
Customer Attachments to Company Towers	Attachment 6	195
Customer Attachments to Company Poles	Attachment 6	858

~~**Annual Attachment Fee:**~~
~~Per Company Tower: $180.33~~
~~Per Company Pole: $179.01~~

Formula Rate Inputs:

1. Customer Post Retirement Benefits Other Than Pensions (PBOP) - ($18,300,000)

2. Customer Depreciation Rates

Transmission Accounts	**Rate**
352	1.56%
353	1.79%
354	1.54%
355	3.04%

356	2.49%
357	1.97%
358	-1.33%
359	0.27%

Distribution Accounts	**Rate**
361	2.44%
362	2.07%
364	3.41%
365	3.19%
366	2.56%
367.1	2.90%
368	
368.1	3.50%
368.2	3.77%
368.3	3.87%
369	
369.1	3.53%
369.20	2.90%
369.21	2.90%
369.22	0.00%
370	
370.1	4.23%
370.2	4.49%
370.3	4.10%
370.35	3.65%
371	0.00%
373	
373.1	5.44%
373.2	5.41%

General Accounts	**Rate**
390	2.05%
391	6.67%
392	6.67%
393	3.04%
394	5.59%
395	5.97%
396	6.67%
397	6.67%
397.1	3.83%
398	6.48%

11. Primary Service for Resale:	None. LNS transmission service is provided by New England Power Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP). Contract Termination Charge provided pursuant to Contract Termination Charge Amendment. Nothing contained herein is intended to modify or otherwise affect the settlements accepted by the Commission in Docket Nos. ER97-678-000 and ER97-2800-000. In the event of a conflict between the Contract Termination Charge Amendment and the settlements, the settlements shall govern.
12. Minimum Demand KW:	None
13. Minimum Term:	None
14. Transmission Service for Partial Requirements Customers:	LNS transmission service provided by New England Power Company (NEP) to Massachusetts Electric Company and Nantucket Electric Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP.)

Massachusetts Electric Company
Distribution Plant Assets Serving NEP Wholesale Transmission Functions

Line No	Municipality Served by NEP		Plant In-Service Facilities		Distribution Asset Investment	Source
1	Georgetown	$	422,084	$	422,084	Internal Plant Records
2	Groveland		120,977	$	120,977	Internal Plant Records
3	Hull		942,574	$	942,574	Internal Plant Records
4	Ipswich		1,751,903	$	1,751,903	Internal Plant Records
5	Merrimac		157,256	$	157,256	Internal Plant Records
6	Princetown		100,777	$	100,777	Internal Plant Records
7	Stamford (GMP)		85,982	$	85,982	Internal Plant Records
8	Rowley		479,715	$	479,715	Internal Plant Records
9	**Sub Total**	$	4,061,268	$	4,061,268	Sum of Lines 1 - 9
10	Salem-Pelham (GSE)	$	679,996	$	679,996	Internal Plant Records
11	**Total MECO Distribution Assets Serving**					
12	**NEP Municipal Customers**			$	4,741,264	Line 9 + Line 10

Notes:
(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

			A	B	C	D	E	F	G	H	I	J				
	Location	Location ID	Square Footage NEP	Square Footage MECO	Square Footage Total	Nep Land Value	Meco Land Value	Devices NEP	Devices MECO	Devices Total	Nep Device Value	Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
1.	NEP - SUB #6 WEBSTER STREET, W	001	33,750	28,500	62,250	17,148.38	339,799.87	8	61	69	3,999.32	56,841.34	1,796,140.79	11,386.33	6,761,590.60	190,827.40
2.	NEP - SUB #8 VERNON HILL	002	17,500	57,950	75,450	136,084.67	49,047.90	4	14	18	6,110.83	22,550.58	735,612.90	109,279.64	962,496.57	16,384.95
3.	NEP - SUB #21 LEICESTER	003	7,560	15,120	22,680	19,796.58	44,761.62	4	2	6	8,817.93	332.15	561,537.70	16,137.40	850,633.55	15,140.49
4.	NEP - SUB #24 GREENDALE PTF	004	37,400	21,550	58,950	238,890.21	109,001.39	7	21	28	14,444.13	41,310.08	4,109,288.07	98,171.36	3,206,592.41	79,478.00
5.	NEP - SUB #25 NASHUA STREET, W	005	20,776	23,512	44,288	97,681.31	15,377.30	6	14	20	78,288.99	23,720.37	2,151,133.22	106,661.30	2,820,248.89	14,329.60
6.	NEP - SUB #26 PONDVILLE	006	8,040	9,360	17,400	80,452.92	3,873.22	4	6	10	14,140.14	656.50	375,558.23	51,759.71	276,418.81	2,052.41
7.	NEP - SUB #27 BLOOMINGDALE	007	13,775	10,150	23,925	248,049.17	17,029.07	4	13	17	40,986.08	6,444.75	2,135,646.29	136,564.51	2,705,183.27	11,321.79
8.	NEP - SUB #41 TEMPLE ST-W BOYL	008	1,950	2,080	4,030	0.00	2,378.70	1	1	2	0.00	299.27	183.70	0.00	74,303.10	1,300.69
9.	NEP - SUB #207 LITCHFIELD STRE	009	0	0	0	36,984.00	140,975.32	0	0	0	0.00	30,796.41	1,303,900.22	0.00	2,686,493.04	0.00
10.	NEP - SUB #210 DUNSTABLE	010	3,750	3,750	7,500	75,468.05	4,165.27	4	1	5	1,500.14	3,490.92	278,573.78	38,034.05	355,200.50	4,875.37
11.	NEP - SUB #219 PROSPECT STREET	011	11,970	13,375	25,345	76,101.20	18,409.48	9	10	19	0.00	75,827.71	641,593.23	40,158.60	849,892.88	44,614.38
12.	NEP - SUB #227 LAUREL CIRCLE,	012	15,990	11,960	27,950	600,988.41	245,407.00	4	2	6	178,988.42	0.00	2,238,487.70	316,819.78	727,652.17	140,397.34
13.	NEP - SUB #304 MILLBURY #4	013	9,520	12,320	21,840	157,924.59	20,012.00	4	9	13	44,478.03	1,915.09	1,927,526.30	119,877.40	1,021,561.81	9,312.50
14.	NEP - SUB #306 SHREWSBURY	014	14,875	13,125	28,000	32,474.60	46,090.07	5	3	8	0.00	15,295.78	847,189.17	15,224.09	2,006,414.58	34,047.52
15.	NEP - SUB #328 NORTH GRAFTON	015	6,375	5,625	12,000	5,408.09	39,559.05	1	2	3	935.44	2,542.06	163,990.03	3,158.97	85,808.15	21,864.99
16.	NEP - SUB #401 MAIN STREET - W	016	9,000	6,500	15,500	0.00	0.00	7	5	12	0.00	0.00	0.00	0.00	0.00	0.00
17.	NEP - SUB #406 NORTH OXFORD #2	017	12,240	10,840	23,080	118,145.34	65,534.23	3	5	8	39,103.03	2,205.10	1,299,621.99	79,932.26	1,493,058.55	35,579.71
18.	NEP - SUB #412 EAST WEBSTER	018	12,878	25,482	38,360	207,553.68	110,487.00	6	13	19	137,040.00	323.98	2,817,573.29	231,640.68	2,153,857.32	37,192.80
19.	MECO - SUB #413 SNOW STREET, S	019	0	0	0	0.00	81,294.73	0	0	0	0.00	14,711.64	0.00	0.00	7,401,980.00	0.00
20.	NEP - SUB #415 WEST CHARLETON	020	17,110	11,890	29,000	190,555.39	47,786.62	2	3	5	49,046.15	0.00	1,096,140.65	107,555.40	502,023.03	28,194.11
21.	NEP - SUB #525 LASHAWAY	021	1,200	2,500	3,700	38,890.22	7,817.38	4	5	9	9,335.05	6,498.95	233,033.30	31,464.68	389,801.62	5,423.31
22.	NEP - SUB #552 MEADOW STREET -	022	29,205	16,240	45,445	209,637.20	60,117.52	8	3	11	228,045.17	904.09	3,310,501.64	137,112.25	805,226.88	39,289.06
23.	NEP - SUB #601 PARK STREET P	023	11,550	23,300	34,850	36,713.97	135,802.58	7	20	27	63.84	22,894.71	1,099,361.76	24,594.25	1,008,058.37	50,941.57
24.	NEP - SUB #602 WESTMINSTER	024	9,000	10,800	19,800	19,518.20	5,440.57	3	3	6	8,941.41	922.14	165,817.71	15,117.88	309,240.19	2,933.81
25.	NEP - SUB #609 EAST WESTMINSTE	025	3,800	9,500	13,300	44,111.26	1,376.27	5	2	7	1,213.54	806.54	531,172.80	31,855.38	380,689.39	969.31
26.	NEP - SUB #612 EAST WINCHENDON	026	8,880	8,520	17,400	111,172.45	7,649.08	2	2	4	22,780.00	0.00	787,894.42	65,831.15	538,392.60	3,903.33
27.	NEP - SUB #1 WEST STREET	027	25,004	36,398	61,402	26,453.92	36,370.01	9	18	27	4,770.78	45,212.59	415,169.02	18,862.56	1,147,241.68	29,879.22
28.	NEP - SUB #7 MINK STREET	028	15,840	19,272	35,112	41,702.98	37,246.86	4	9	13	0.00	6,148.60	928,068.07	22,890.77	764,996.04	18,693.98
29.	NEP - SUB. #8 CHARTLEY POND, A	029	24,800	15,525	40,325	66,217.53	32,932.66	6	10	16	11,872.40	3,379.99	2,190,887.93	32,914.00	3,495,833.41	21,521.08
30.	NEP - SUB #9 READ STREET PTF	030	32,700	25,200	57,900	84,095.92	96,526.99	14	14	28	26,493.15	348.54	4,675,929.66	49,845.12	3,628,462.96	54,692.71
31.	NEP - SWANSEA SUB -- PTF	031	0	9,000	0	134,397.38	0.00	5	9	14	10,545.75	6,428.78	1,255,762.64	70,054.15	905,962.60	2,295.72
32.	NEP - DIGHTON SUB	032	0	6,750	0	52,861.64	0.00	5	5	10	12,125.45	5,932.46	336,047.87	27,175.66	501,234.51	2,966.23
33.	NEP - ROBINSON AVE SUB -- PTF	033	0	0	0	63,115.69	0.00	0	0	0	74,235.01	0.00	1,712,980.55	0.00	0.00	0.00
34.	NEP - HATHAWAY SUB	034	114,952	30,180	145,132	4,749.00	0.00	6	21	27	39,594.75	0.00	862,668.57	31,784.11	0.00	0.00
35.	NEP - BELL ROCK RD SUB -- PTF	035	0	0	0	13,734.74	0.00	0	0	0	48,914.56	0.00	819,854.24	0.00	0.00	0.00
36.	NEP - SUB #310 SOUTH MARLBOROU	036	4,000	4,500	8,500	51,975.36	3,519.59	7	5	12	5,248.26	6,506.94	982,969.37	29,702.71	462,640.63	5,451.82
37.	NEP - SUB #311 MARLBOROUGH - F	037	7,614	24,255	31,869	5,231.34	63,366.89	6	8	14	26,631.52	30,927.17	2,101,730.24	19,198.82	1,175,765.83	28,393.74
38.	NEP - SUB #312 WESTBOROUGH P	038	9,849	14,700	24,549	71,564.72	20,055.97	9	8	17	33,433.95	5,358.04	2,876,156.00	58,586.97	999,998.30	10,883.00
39.	NEP - SUB #313 WOODSIDE, NORTH	039	15,727	11,719	27,446	34,641.37	28,783.50	6	4	10	18,287.95	2,355.50	3,102,550.08	22,107.04	1,318,005.36	17,906.25

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

01/28/2010

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

	Location	Location ID	A ----Square Footage---- NEP	B MECO	C Total	D Nep Land Value	E Meco Land Value	F ------Devices------ NEP	G MECO	H Total	I Nep Device Value	J Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
40.	NEP - SUB #314 EAST MAIN STREE	040	10,875	11,600	22,475	191,168.61	10,144.94	2	4	6	60,031.84	4,329.93	1,235,573.76	138,685.35	360,067.25	6,352.30
41.	NEP - SUB #318 NORTH MARLBOROU	041	14,352	11,394	25,746	319,510.00	55,836.00	2	1	3	172,284.00	0.00	1,162,587.03	198,837.38	1,322,291.38	31,122.99
42.	NEP - SUB #320 WHITINS POND	042	10,140	20,410	30,550	107,256.91	11,975.33	2	4	6	55,392.17	63,583.00	3,087,458.20	108,588.30	2,549,580.42	25,166.83
43.	NEP - SUB #321 UXBRIDGE PTF	043	40,500	101,400	141,900	227,761.21	56,829.90	17	3	20	185,812.54	0.00	3,315,576.24	190,630.04	1,713,685.85	16,219.25
44.	NEP - SUB #335 DEPOT STREET	044	8,814	10,735	19,549	12,848.46	92,564.27	4	14	18	0.00	6,903.65	863,784.88	7,055.09	1,785,720.87	43,271.22
45.	NEP - SUB #336 ROCKY HILL, MIL	045	12,285	16,065	28,350	85,206.00	19,724.00	2	2	4	119,416.00	0.00	2,732,838.62	107,994.24	1,345,186.21	8,546.41
46.	NEP - SUB #344 BEAVER POND --	046	14,280	11,620	25,900	306,348.94	10,172.50	7	8	15	119,442.30	1,449.12	2,518,782.02	201,126.71	1,989,604.48	6,285.42
47.	NEP - SUB #348 UNION ST PTF	047	0	16,150	0	114,448.57	0.00	7	10	17	81,189.66	0.00	2,790,966.91	94,817.01	664,886.55	0.00
48.	NEP - SUB #3422 SOUTH WRENTHAM	048	30,526	23,714	54,240	100,799.84	24,437.91	6	19	25	26,375.79	37,662.82	3,143,914.89	64,115.29	5,662,290.77	22,792.73
49.	NEP - SUB #1 FIELD STREET	049	13,750	151,850	165,600	379,343.86	183,207.68	8	45	53	14,131.00	46,457.54	5,025,804.45	359,856.95	5,275,326.98	22,216.68
50.	NEP - SUB #9 EAST WEYMOUTH	050	4,800	9,680	14,480	15,311.88	143,742.00	4	15	19	8,911.09	33,099.80	415,833.17	17,271.30	1,417,650.78	54,617.98
51.	NEP - SUB #11 NORTH QUINCY	051	40,236	2,100	42,336	677,183.52	27,735.86	7	13	20	170,123.42	19,413.83	6,537,136.31	144,168.53	1,266,013.74	33,155.00
52.	NEP - SUB #12 MID-WEYMOUTH --	052	17,360	27,860	45,220	151,158.94	11,093.41	4	3	7	52,196.21	84,837.00	1,449,566.28	115,500.32	2,246,869.92	52,734.62
53.	MECO - SUB #95 PHILLIPS LANE,	053	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	3,019,216.13	0.00
54.	NEP - SUB #97 SOUTH RANDOLPH	054	8,640	13,635	22,275	339,768.52	58,090.00	2	4	6	28,203.45	2,130.00	2,230,762.72	226,775.55	2,323,492.94	23,243.04
55.	NEP - SUB #507 WILBRAHAM	055	6,000	6,900	12,900	63,192.39	149,857.08	2	6	8	0.00	161,900.00	1,045,554.74	33,801.61	1,295,153.93	110,173.53
56.	NEP - SUB #508 EAST LONGMEADOW	056	11,700	6,500	18,200	82,407.17	38,715.44	7	6	13	4,664.42	1,418.66	1,151,328.01	31,580.23	965,739.75	25,654.10
57.	NEP - SUB #509 BELCHERTOWN	057	5,060	7,590	12,650	27,536.74	31,336.61	2	3	5	14,495.00	42,682.64	561,030.13	25,219.04	707,708.61	29,607.70
58.	NEP - SUB #303 LITTLE REST ROA	058	10,220	14,000	24,220	312,780.67	71,683.00	2	4	6	92,517.00	357.86	1,411,423.58	242,468.31	710,356.89	30,369.50
59.	NEP - SUB #522 SHAKER ROAD	059	8,160	9,240	17,400	24,850.82	88,505.33	2	2	4	57,427.68	0.00	771,049.83	41,909.63	528,038.58	41,509.00
60.	NEP - SUB #523 THORNDIKE	060	0	13,200	0	405,595.32	0.00	2	3	5	69,808.00	908.19	1,666,914.85	234,826.49	545,665.51	363.28
61.	NEP - SUB #524 HAMPDEN	061	5,369	5,005	10,374	14,040.94	16,346.30	1	2	3	0.00	22,300.89	165,913.05	6,774.75	410,444.32	15,892.10
62.	MECO - SUB #527 FIVE CORNERS,	062	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	1,597,270.96	0.00
63.	NEP - SUB #604 BARRE-FORMERLY	063	3,600	16,000	19,600	48,228.30	11,438.51	4	7	11	6,950.95	0.00	283,554.43	43,792.35	418,718.88	2,101.25
64.	NEP - SUB #704 SHUTESBURY -- P	065	6,600	2,800	9,400	96,594.12	6,058.21	2	1	3	72,821.00	9,209.37	911,982.61	53,046.63	112,601.32	10,393.36
65.	NEP - SUB #705 WENDELL DEPOT	066	8,160	9,240	17,400	75,205.99	6,389.78	2	3	5	44,332.66	4,904.20	826,983.64	66,533.98	712,796.98	4,958.49
66.	MECO - SUB #1103 LENOX DEPOT,	067	0	0	0	0.00	101,199.01	0	0	0	0.00	16,600.34	0.00	0.00	856,447.37	0.00
67.	NEP - SUB #7 REVERE PTF	068	31,000	0	62,500	0.00	153,280.41	5	43	48	0.00	38,160.63	2,370,342.93	0.00	2,991,494.69	80,003.42
68.	NEP - SUB #16 MAPLEWOOD -- PTF	069	10,800	22,374	33,174	6,202.17	170,930.10	8	20	28	0.00	50,797.72	2,946,953.29	4,182.74	3,094,914.77	70,167.75
69.	NEP - SUB #37 EVERETT, EVERETT	070	51,650	66,425	118,075	122,807.89	43,553.49	14	35	49	0.00	8,792.23	2,970,854.66	69,091.72	861,939.98	21,562.24
70.	NEP - SUB #29 WEST SALEM	071	38,395	32,986	71,381	695,562.86	47,029.49	9	12	21	95,116.17	1,789.45	3,498,402.30	375,768.98	2,360,736.22	26,064.12
71.	NEP - SUB #49 RAILYARD, SALEM,	072	10,935	9,315	20,250	29,865.00	2,852.00	4	5	9	48,346.73	1,276.00	3,426,979.90	40,599.34	2,029,333.05	2,107.13
72.	NEP - SUB #51 EAST BEVERLY - C	073	18,977	43,375	62,352	149,200.19	24,008.01	8	22	30	47,893.07	37,803.43	4,518,100.04	138,903.64	5,266,867.31	17,390.21
73.	NEP - SUB #21 LYNN, LYNN -- PT	074	17,072	74,635	91,707	17,624.42	220,842.21	5	76	81	0.00	38,789.59	1,298,285.74	14,342.75	8,862,470.75	43,514.14
74.	NEP - SUB #2 NORTH CHELMSFORD	075	12,000	23,900	35,900	19,522.42	175,421.24	6	21	27	5,497.47	21,731.99	1,985,884.48	17,272.01	4,642,617.53	63,472.17
75.	NEP - SUB #3 PERRY STREET	076	11,200	10,640	21,840	115,075.11	88,187.38	2	48	50	45,243.12	32,262.13	603,670.87	99,497.99	1,975,149.39	46,512.97
76.	NEP - SUB #16 MEADOWBROOK-OFF	077	24,000	31,900	55,900	100,985.04	40,848.74	6	23	29	9,514.00	15,105.58	967,041.04	65,177.72	2,943,978.02	20,661.71
77.	NEP - SUB. #45 SOUTH BROADWAY	078	15,705	8,908	24,613	111,689.53	21,848.30	4	6	10	16,516.00	29,083.85	1,828,299.74	50,330.04	782,251.66	25,574.94
78.	NEP - SUB #59 EAST TEWKSBURY	079	6,000	6,500	12,500	110,272.85	9,905.57	4	9	13	40,354.09	0.00	1,884,782.19	85,279.02	3,119,773.89	4,754.67

Determination of Asset Allocation to Affiliates For Year Ending 12/31/2008

01/28/2010

Note: Allocation of NEP Investment to MECO = ((B/C)*D)+((G/H)*I) (with rounding)
Allocation of MECO Investment to NEP = ((A/C)*E)+((F/H)*J) (with rounding)

	Location	Location ID	A Square Footage NEP	B Square Footage MECO	C Square Footage Total	D Nep Land Value	E Meco Land Value	F Devices NEP	G Devices MECO	H Devices Total	I Nep Device Value	J Meco Device Value	Nep Investment	Allocation of NEP Investment To MECO	Meco Investment	Allocation of MECO Investment To NEP
79.	NEP - SUB #70 BILLERICA	080	10,530	21,710	32,240	4,761.10	83,719.89	4	19	23	8,431.80	9,522.47	4,852,186.40	10,171.63	2,990,118.28	28,998.87
80.	NEP - SUB #75 EAST DRACUT	081	8,040	9,360	17,400	12,813.53	13,974.72	2	3	5	23,447.92	815.56	3,319,100.74	20,961.15	1,558,804.96	6,783.94
81.	NEP - SUB #78 NORTH DRACUT	082	10,680	28,200	38,880	144,783.38	22,444.27	2	2	4	9,410.47	39,996.43	770,518.42	109,716.62	762,073.44	26,163.66
82.	NEP - SUB #92 PINEHURST	083	10,640	8,680	19,320	267,177.65	11,924.63	5	8	13	47,710.17	9,130.60	1,989,419.01	149,403.76	1,647,173.28	10,078.52
83.	NEP - SUB #18 KING STREET	084	0	19,800	0	110,215.27	0.00	19	2	21	40,511.97	0.00	11,789,254.72	26,726.41	0.00	0.00
84.	NEP - SUB #8A WEST ANDOVER	085	15,120	10,530	25,650	151,641.95	36,716.39	5	13	18	46,092.62	42,073.55	2,333,352.85	95,537.11	1,649,443.82	33,332.34
85.	NEP - SUB #54 BURTT RD- EXECUT	086	0	16,520	0	246,969.32	0.00	6	4	10	134,335.00	0.00	2,754,549.40	188,653.34	2,232,833.56	0.00
86.	NEP - SUB #63 WEST METHUEN - P	087	18,639	14,592	33,231	196,432.79	15,400.30	8	10	18	407.01	19,610.21	2,160,477.11	86,479.77	1,512,697.77	17,352.81
87.	NEP - SUB #74 EAST METHUEN –	088	11,640	19,800	31,440	97,311.63	20,092.45	6	9	15	35,732.93	17,635.66	2,814,347.58	82,726.62	2,359,489.63	14,492.49
88.	MECO - AUBURN ST SUB 115KV	089	0	0	0	0.00	0.00	0	0	0	0.00	0.00	0.00	0.00	62,943.48	0.00
89.	NEP - BRIDGEWATER SUB -- PTF	090	0	0	0	305,750.83	0.00	0	0	0	217,443.36	0.00	12,996,518.82	0.00	0.00	0.00
90.	NEP - SUB #201 AYER PTF	092	58,240	35,840	94,080	223,543.03	5,966.09	30	3	33	22,351.78	28.65	5,395,456.42	87,201.67	233,119.15	3,719.06
91.	NEP - SUB #216 FITCH ROAD PT	093	34,400	20,250	54,650	94,593.14	8,516.50	15	1	16	56,018.92	0.00	5,678,229.28	38,547.94	1,475,879.96	5,361.14
92.	NEP - SUB #225 PRATTS JUNCTION	094	0	1,750	0	210,414.14	0.00	29	8	37	263,153.42	0.00	21,096,309.95	57,693.34	1,319,187.82	0.00
93.	NEP - SUB #237 SANDY POND, AYE	095	252,000	81,000	333,000	747,675.13	1,793.24	42	7	49	296,243.06	5,357.07	20,311,680.95	224,167.72	286,109.52	5,948.67
94.	MECO - BATES ST SUB 14KV 115	096	0	0	0	0.00	0.00	5	25	30	0.00	2,948.93	0.00	0.00	2,427,634.92	491.59
95.	NEP - SUB #317 NORTHBOROUGH RO	097	69,680	30,160	99,840	317,729.16	33,189.41	20	18	38	68,342.34	0.00	8,270,334.34	128,359.75	1,676,061.68	23,162.89
96.	NEP - SUB #501 WARE #1 PTF	098	44,307	24,310	68,617	73,849.35	26,753.43	12	5	17	45,536.07	3,054.27	4,147,230.89	39,556.98	579,087.11	19,430.70
97.	NEP - SUB #503 PALMER - BLANCH	099	104,000	71,600	175,600	252,845.06	51,673.68	29	8	37	194,467.45	58,925.49	11,060,804.92	145,128.79	1,102,047.47	76,792.12
98.	NEP - SUB #702 CHESTNUT HILL	100	6,880	9,000	15,880	117,221.62	85,649.34	6	5	11	113,823.00	0.00	2,616,501.22	118,173.77	811,940.79	37,103.29
99.	NEP - SUB #21 ADAMS PTF	101	108,000	72,000	180,000	413,717.23	3,036.85	31	3	34	126,098.36	792.89	6,097,968.08	176,608.77	2,020,920.85	2,545.07
100.	NEP - SUB #22 TEWKSBURY PTF	102	590,600	205,600	796,200	340,429.45	6,341.92	81	1	82	528,463.37	2,298.03	36,420,515.92	94,346.14	453,210.23	6,974.43
101.	NEP - SUB #43 WARD HILL PTF	103	96,250	47,520	143,770	341,056.49	32,023.70	32	10	42	412,579.76	401.56	62,672,526.93	210,954.41	2,385,786.60	21,745.82
102.	NEP - DEERFIELD #5 SWITCHYARD-	104	7,098	9,703	16,801	141,803.44	3,363.01	4	2	6	9,333.21	0.00	681,298.37	85,002.25	85,028.35	1,420.87
103.	NEP - BEAR SWAMP - TRANSMISSIO	105	188,850	22,500	211,350	1,047,224.60	1,970.14	18	2	20	160,417.40	0.00	5,178,302.77	127,571.16	88,928.69	1,760.32
			2,753,335	2,181,519	4,883,184	14,967,805.97	4,628,335.68	775	1001	1776	5,825,769.39	1,492,221.58	361,881,055.75	8,190,969.11	165,227,835.59	2,365,249.04

Revised
Massachusetts Electric Company
Distribution Plant Assets Serving NEP Wholesale Transmission Functions
Buildings and Facilities

Line No	Mass Electric Location Identifiers	Building/Facility Description	FERC Accounts	(1) Total Mass Electric Investment	Source	(2) Facility Total Sq. Ft.	(3) Facility Area Used by NEP	(4)=(1)*((3)/(2)) (4) Investment Allocated to NEP
1	157, 192	Beverly, MA	390	$761,589	Internal Plant Records	40,230	1,600	$30,289
2	92, 296, 660	Leominster, MA	389, 390	804,671	Internal Plant Records	17,897	800	35,969
3	92, 160	North Andover, MA	389, 390	453,939	Internal Plant Records	106,786	800	3,401
4	92, 298, 323	Leeds (Northampton), MA	389, 390	1,676,832	Internal Plant Records	23,669	600	42,507
5	24858652	Northbridge/Sutton, MA	389, 390	13,663,277	Internal Plant Records	86,741	12,534	1,974,332
7	92, 309, 325	Worcester, MA	389, 390	6,812,142	Internal Plant Records	147,902	1,200	55,270
7	Total			$24,172,450				$2,141,768

New England Power Company Assets
Used by Massachusetts Electric Company
For Retail Distribution Service

Transmission Assets (13.8 and 23 kV)

Line No	NEP Location Identifier	NEP Circuit Identifier	Description	Total Plant In-Service Investment	Source
1	4205	1201	MH-12699 Washington St to Field St Sub	$0.00	Internal Plant Records
2	4206	1202	MH-12699 Washington St to Field St Sub	0.00	Internal Plant Records
3	4207	1213X	MH-12700 Washington St to Field St Sub	0.00	Internal Plant Records
4	4208	1219	MH-12700 Washington St to Field St Sub	52,946.16	Internal Plant Records
5	4209	1224	MH-12700 Washington St to Field St Sub	0.00	Internal Plant Records
6	4210	1225	MH-12700 Washington St to Field St Sub	43,448.35	Internal Plant Records
7	4211	2208	MH-12699 Washington St to W. Quincy Sub	1,240,922.54	Internal Plant Records
8	4212	2215	MH-12699 Washington St to W. Quincy Sub	195,496.45	Internal Plant Records
9	4213	2211	MH-12700 Washington St to W. Quincy Sub	806,490.31	Internal Plant Records
10	4214	2212	MH-12700 Washington St to W. Quincy Sub	59,684.57	Internal Plant Records
11	4215	2216	MH-12700 Washington St to W. Quincy Sub	154,364.13	Internal Plant Records
12	4252		Quincy BECO	1,522,019.97	Internal Plant Records
13	**Totals**			**$4,075,372.48**	Sum of Lines 1 - 12

Notes:

(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

New England Power Company Assets
Used by Massachusetts Electric Company
For Retail Distribution Service

Distribution Plant Assets

Line No	NEP Location Identifier	Description	Total Plant In-Service Investment	Source
1	15	Fitch Road Substation	$0.00	Internal Plant Records
2	86	Leicester Substation #321	0.00	Internal Plant Records
3	126	Millbury #3 Substation #303	0.00	Internal Plant Records
4	7006	North Attleboro Distribution Feeder 8-L2 Feeder	31,240.82	Internal Plant Records
5	7007	Westminster Sub to Digital Equipment 13.8 KV Feeder	18,620.83	Internal Plant Records
6	7008	#1 23 KV Line from Sub #63 to #2353 Line	44,279.97	Internal Plant Records
7	7009	#2 23 KV Line from Sub #63 to #2376 Line	31,352.83	Internal Plant Records
8	7010	13 KV Getaway from Sub #63 to NEP R/W's	25,552.13	Internal Plant Records
9	7011	#2301 & #2302 Lines 23 KV Taps	56,993.68	Internal Plant Records
10	7012	Line 70L1 13 KV Distribution Feeder	26,315.35	Internal Plant Records
11	7014	13.8 KV Line - Westminster	10,642.11	Internal Plant Records
12	7015	E5 and F6 Getaway Wsub #704 Shutesbury	13,273.88	Internal Plant Records
13	7017	Forge Park Industrial Development 13.8 KV Line	17,547.88	Internal Plant Records
14	8002	Metropolitan District Commission - Wachusett Dam	9,268.37	Internal Plant Records
15	8053	Water Street Sub - Mass Electric	1,872.70	Internal Plant Records
16	8054	Lawrence Street #1 Substation - Mass Electric	2,960.79	Internal Plant Records
17	8057	Malden #5 Station - Mass Electric	0.00	Internal Plant Records
18	8071	Hampshire Road Granite State Metering Point	3,053.87	Internal Plant Records
19	FR3	Sykes Road Substation	0.00	Internal Plant Records
20	**Totals**		**$292,975.21**	Sum of Lines 1 - 19

Notes:

(1) The list of facilities identified in this Schedule will not be updated without the filing of a revision to this service agreement with the FERC.

New England Power Company
Detail of Massachusetts Electric Line Attachments
NEP to MECO Integrated Facilities Usage Fees

Line No	District	NEP Pole Locations with MECO Line Attachments	Number of Poles	Number of Towers	Structure Numbers	Source
1	Worcester	#5 and #6 (Auburn)	45		1749A-1766, !768, 1769-1794	Internal Plant Records
2		#5 and #6 (Leicester)	5		1600-1604	Internal Plant Records
3		#127 and #128	5		1948-1952	Internal Plant Records
4		A1 and B2 (Greendale to Pratts Jct)		52	Towers 822-833, 835-874	Internal Plant Records
5				51	Towers 821A-874D including 852B&C, 873A, 874A-C	Internal Plant Records
6					excluding 848A, 849A, 850A, 854A, 865A, 870A, 872A	Internal Plant Records
7		**Worcester Totals**	**55**	**103**		Sum of Lines 1 - 5
8						
9	Palmer	Wilbrahan Sub #507	1		251	Internal Plant Records
10		E5 and F6 Lines	14		at Meadow St Sub #'s 1432-1437, 1437A, 1438-1444	Internal Plant Records
11			149		Meadow St - Lashaway Sub #'s 1306-1431, 1364L, 1363L,	Internal Plant Records
12					1346A, 1332S, 1285-1305	Internal Plant Records
13			31		Primary attachments on #14 Line #'s 63-72, 118, 250-271	Internal Plant Records
14			5		Primary attachments on #15 Line #'s 99-102, 155	Internal Plant Records
15			1		Secondary attachments on #15 Line #'s 4A	Internal Plant Records
16		**Palmer Totals**	**201**	**0**		Sum of Lines 9 - 15
17						
18	Gardner	#127 and #128	36		1569-1606	Internal Plant Records
19						
20		**Gardner Totals**	**36**	**0**		Sum of Line 18
21						
22	Hopedale	#5 and #6 Millbury - Auburn	119		1795-1910, 1887A, 1880A, 1881A and 1884A	Internal Plant Records
23		#11 and #12 Lines	110		Lackey Pond - Uxbridge Ser Twr 262-372	Internal Plant Records
24			48		Uxbridge Sub - Uxbridge Ser Twr 1-48	Internal Plant Records
25			117		321W0 Tap - Uxbridge Ser Twr - 2-118	Internal Plant Records
26		X24 Line	10		Feeder 310W5 attached to poles 1-5, 6A, 13-16	Internal Plant Records
27						
28		**Hopedale Totals**	**404**	**0**		Sum of Lines 22 - 26
29						
30	Southbridge	S-19 Line	18		239-252, 265-267, 135	Internal Plant Records
31						
32		**Southbridge Totals**	**18**	**0**		Sum of Line 30
33						
34	Attleboro	24 Rehoboth Tap	33		"K" frames #118-150	Internal Plant Records
35						
36		**Attleboro Totals**	**33**	**0**		Sum of Line 34
37						
38	North Adams	#7 and # 8 Lines	38		telephone lines, poles #381-440 plus 1 un-numbered	Internal Plant Records
39		G-17 Bennington-Adams Line		46	Feeder #1 attached to Q117 towers	Internal Plant Records
40		Q117 Adams - Walker		46		Internal Plant Records
41		N14	31		#63-72, 118, 250-271	Internal Plant Records
42		O15	6		#4A, 99-102, 155	Internal Plant Records
43		S197	30		Feeder #1019W1 getaway	Internal Plant Records
44						
45		**North Adams Totals**	**105**	**92**		Sum of Lines 38 - 43
46						
47	Malden	F-158S	6		#'s 148-153	Internal Plant Records
48						
49		**Malden Totals**	**6**	**0**		Sum of Line 47
50						
51		**Total Poles and Towers**	**858**	**195**		Sum of Lines 7,16,20, 28,32,36,45 and 49

FERC rendition of the electronically filed tariff records in Docket No. ER11-04264-000
Filing Data:
CID: C001305
Filing Title: Filing to Implement Settlement Agreement in Docket ER10-523
Company Filing Identifier: 61
Type of Filing Code: 80
Associated Filing Identifier:
Tariff Title: Tariffs, Rate Schedules, Agreements
Tariff ID: 78
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Title Page, Tariff No. 1 Title Page, 0.0.0, A
Record Narative Name:
Tariff Record ID: 4
Tariff Record Collation Value: 1074200000   Tariff Record Parent Identifier: 0
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

FERC ELECTRIC TARIFF

SECOND REVISED VOLUME NUMBER 1

OF

NEW ENGLAND POWER COMPANY

Filed with

FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this
Tariff should be addressed to:

Director of Rates
New England Power Company
40 Sylvan Road
Waltham, Massachusetts 02451

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Table of Contents, Table of Contents, 0.0.0, A
Record Narative Name:
Tariff Record ID: 5
Tariff Record Collation Value: 1074200200 Tariff Record Parent Identifier: 4
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

NEW ENGLAND POWER COMPANY

Primary Service for Resale

TABLE OF CONTENTS

Schedule III-C	Terms and Conditions - Service for Resale to Interruptible Customers
Schedule IV	Form of Service Agreement

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Schedule I, Schedule I, 0.0.0, A
Record Narative Name:
Tariff Record ID: 6
Tariff Record Collation Value: 1074200400 Tariff Record Parent Identifier: 4
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Priority Order: 500
Record Change Type: NEW
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Associated Filing Identifier:

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers
General Terms and Conditions

Schedule I

A. Tariff.

Primary Service for resale and transmission service for Partial Requirements Customers are available only upon execution of a Service Agreement with the Company in the form set forth hereinafter.

Each such Service Agreement will incorporate these general terms and conditions (Schedule I), the Company's currently effective rate for primary service for resale (Schedule II), the terms and conditions applicable to the type of service to be rendered at said rate (Schedule III) and the specific interconnection arrangements with the Customer.

The Company will file each such Service Agreement with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder.

B. Amendments.

It is agreed that the Company shall have the right at any time to amend the General Terms and Conditions set forth in this Schedule I to the tariff, the Rate Provisions set forth in Schedule II to the tariff, the Terms and Conditions governing specified types of service set forth in Schedule III to the tariff, and the form of Service Agreement set forth in Schedule IV to the tariff, by serving an appropriate statement of such amendment upon the Customer and filing the same with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order duly issued by such agency.

C. Regulation.

This tariff, any Service Agreement executed pursuant thereto, and all the rights, obligations and performance of the parties to such service agreement, are subject to the Federal Power Act and to all other applicable state and federal laws and to all duly promulgated rules, regulations and orders of the Federal Power Commission and any other regulatory agency having jurisdiction in the premises.

The obligations of the parties are further subject to and conditioned upon their securing and retaining all rights-of-way, franchises, locations, permits and other rights and approvals necessary in order to permit service to be rendered as set forth in the Service Agreement, and each party agrees to use its best efforts to secure and retain all such rights-of-way, franchises, and other rights and approvals.

D. Availability of primary service for resale.

Primary service for resale is available only to electric utilities (including municipalities) engaged in the distribution of electricity to the public, whose electric requirements are supplied in whole or in part by the Company, either directly or over facilities for the use of which the Company has contractual arrangements.

Electricity so supplied is available for the Customer's own use and for resale to ultimate customers in the Customer's service area as it may exist from time to time, which area shall consist of one or more Districts to be specified in the Service Agreement. If the Customer's service area consists of two or more Districts, all provisions of the tariff shall apply to each District separately.

Primary service for resale is also available for sales for resale by the Customer (1) to electric utilities served by the Customer as of the date of and as specified in the Service Agreement; (2) to additional electric utilities which shall then be specified in the Service Agreement; and (3) under convenience contracts for the supply of electricity to borderline customers. With reference to sales under (2) above, the Customer shall give to the Company seven years' notice of intention to serve such utilities; the Customer shall furnish such information as the Company may reasonably request; and the parties shall establish mutually agreeable reasonable terms in connection therewith.

Service for Resale to Interruptible Customers under Schedule III-C is available only to utilities who are also taking service under Schedule III-A or III-B.

The Customer's sources of supply other than the Company shall be specified in the Service Agreement; and seven years' notice shall be given by the Customer to the Company of a change in Customer's source or sources, and such change shall be implemented pursuant to mutually agreed upon reasonable terms.

E. Availability of transmission service.

The types of transmission service available to the Partial Requirements Customer are specified in Schedule III to the tariff, and the Company will consider requests for additional types of transmission service; in each case to the extent that the Company deems its existing and planned transmission capacity can accommodate such additional service without additional new construction. In cases where new construction may be required to accommodate additional types of transmission service, the Company reserves the right in its discretion either to refuse to undertake such further service, or to request financial assurance that any additional transmission investments and costs will be adequately provided for.

F. Character of primary electric service.

Electricity will be supplied in the form of three-phase, sixty-hertz alternating current at the nominal voltage or voltages specified in the Service Agreement.

The Company will maintain and operate its interconnected generating and transmission system, together with any delivery facilities required for service to the Customer, in accordance with good utility practice. The Company will use due diligence in maintaining an aggregate capacity of such facilities sufficiently in excess of current Demand to allow for the Customer's expected load growth, and the Customer will keep the Company informed as to expected trends of its load growth.

The Company shall not be liable in damages to the Customer for any failure to supply electricity nor to provide transmission service in accordance with the preceding paragraphs if prevented from doing so by reason of storm, flood, earthquake, fire, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or other public authority, or any cause beyond its reasonable control; and shall not be liable in damages to the Customer for any reduction in voltage or interruption of service resulting from the operation in accordance with good utility practice of an emergency load-reduction program; but in any such case the Company will exercise due diligence to remove the cause of any disability at the earliest practicable time. The Company and the Customer shall have the obligation to operate in accordance with good utility practice, including an emergency load reduction program, and upon request, to consult with each other in regards thereto.

G. Delivery and ownership of facilities.

1. All deliveries will be made a single delivery point in each District (which may also be used to serve other customers of the Company or affiliated

companies of the New England Electric System), except where District load can be more feasibly served by multiple delivery points. The Service Agreement shall set forth with respect to each District of the Customer's system the point or points of delivery, the delivery voltage or voltages and the ownership of transformation and metering equipment.

2. Deliveries at each delivery point will be made at a single voltage except as otherwise provided in the Service Agreement.

3. All lines, apparatus and other equipment up to the point of delivery shall be supplied, maintained and operated by the Company or affiliated companies of the New England Electric System, and all such equipment beyond such point of delivery shall be supplied, maintained and operated by the Customer. The Customer shall, however, supply free of cost a suitable place for the installation of the Company's metering equipment and any of the Company's lines, or other equipment which it is proper to locate on the Customer's property, and the Company shall have access to the Customer's property for all reasonable purposes in connection therewith.

4. All the Customer's lines, apparatus and equipment (and the maintenance, operation and adjustment of the same) which are connected to the facilities of the Company, and the maintenance, operation and adjustment of which may adversely affect the operation of the Company's facilities, shall be subject to the reasonable inspection and approval of the Company.

5. The Customer assumes all responsibility for electricity beyond the point of delivery, and the Company shall not be liable for damage to the person or property of the Customer or of its employees or of any other persons resulting from the use of electricity beyond the point of delivery.

Variations from the provisions of paragraphs 1 through 5 above will be permitted, in the discretion of the Company, if and to the extent that equitable adjustments are provided for and set forth in the Service Agreement.

H. <u>Metering.</u>

The Company reserves the right to determine the metering installations and will supply the metering equipment for determining the quantity and conditions of supply of electricity delivered hereunder. Any exceptions to this provision shall be reflected in the Service Agreement.

If at any time such equipment shall be found to be inaccurate by more than

2% up or down, the owner shall make it accurate and the charges and meter readings for the period of inaccuracy, so far as the same can reasonably be ascertained, shall be adjusted. However, no adjustment prior to the beginning of the next preceding month shall be made except by mutual agreement.

In addition to regular routine tests, the owner shall have any such meter tested at any time upon written request of the other party, and if such meter prove accurate within 2% up or down the expense of the test shall be borne by the party requesting the test.

I. Transmission losses.

Unless otherwise specified in the tariff, all losses incurred in providing transmission service hereunder shall be for the account of the Customer, and delivery of the aggregate quantity of electricity received for transmission, less such losses, shall constitute full performance by the Company. When segregation of energy flows is required to determine such losses, the Company will calculate the same in accordance with good engineering practice.

J. Billing and payment.

Bills for each month shall be rendered during the first part of the next succeeding month and shall be due when rendered.

As used herein the term “month” shall refer to the period between two meter readings each of which shall have been taken within two days of the end of successive calendar months.

When all or part of any bill shall remain unpaid for more than thirty (30) days after the rendering thereof by the Company, interest at the rate of 1 ½% per month shall accrue to the Company from and after the rendering of said bill and be payable to the Company on either: (1) such unpaid amount or (2) in the event the amount of the bill is disputed, the amount finally determined to be due and payable.

Notwithstanding the foregoing, no late payment penalty shall be imposed upon any customer where payment is made within forty-fine (45) days of the rendering of the bill by the Company provided that each of the following conditions are met: 1) the average prior calendar year’s monthly billing to such customer was less than $45,000; and 2) payment of such bill within thirty (30) days by such customer would cause undue hardship because of the fact that one or more part-time employees or officials are essential to the processing of payment by such customer. A letter from an appropriate official of a customer certifying that one or more part-time employees are essential to the processing of payment shall constitute satisfactory evidence that condition 2 herein has been met.

In addition, no late payment penalty shall be imposed upon any customer electing to make installment payments with respect to any bill so long as the weighted average payment date, based on the amount of each payment, is no later than 30 days after the date of the rendering of the bill.

K. Remedies.

If any bill remains unpaid for more than sixty days, except amounts in dispute, the Company may apply to the regulatory agency having jurisdiction to suspend delivery of electricity until full payment has been made of all amounts due.

If either party shall have defaulted in any of its obligations and such default shall have continued for and not been remedied within sixty days after receipt of a written notice from the other party specifying the nature of such default in reasonable detail, the other party may by written notice terminate the Service Agreement at the end of the next succeeding calendar month. No delay by either party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which other party is legally entitled.

L. Hours of Labor.

The Company agrees to comply with the provisions of the General Laws of Massachusetts, Chapter 149, Section 34, as amended, with reference to the hours of laborers, workmen or mechanics in its employ, so far as the same may be applicable to work under this tariff.

M. Notices.

Notices by the Company or the Customer shall be in writing, mailed or delivered to the respective addresses set forth in the Service Agreement. Either party may change its address by written notice to the other.

N. Term.

Once initiated, service under this tariff shall continue until terminated by either party giving to the other at least seven years' written notice of termination directed to the end of a calendar month.

A Customer that seeks to terminate service without providing the notice required under this tariff and its service agreement and that has not otherwise agreed to a settlement of its early termination costs may exercise an option to terminate service under this tariff early by giving the Company thirty days' written notice directed to the end of a calendar month and paying the Contract Termination Charge applicable under Schedule II-C of this tariff. The Contract Termination Charge shall be payable in equal monthly installments of principal and interest, the first payment to be made within 30 days after the date of termination of service ("Early Termination Date"), over the remaining term of the Customer's notice period (or such shorter term, or in a single payment, as agreed by the Company and the Customer). The Customer's payments shall include carrying charges on the unpaid amount of the Contract Termination Charge at the interest rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. 35.19a) effective on the Early Termination Date and compounded monthly. The Company reserves the right to require the Customer to provide security in a form appropriate to the Company and consistent with commercial practices to protect the Company against the risk of non-payment. This paragraph shall not apply to Customers that have entered into settlement agreements with the Company allowing early termination of service under this tariff and establishing the recovery of contract termination charges. The Company at its discretion may waive the thirty days' notice provision under this paragraph.

O. Successors and assigns.

The executed service agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties.

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Schedule II-A, Schedule II-A, 0.0.0, A
Record Narative Name:
Tariff Record ID: 7
Tariff Record Collation Value: 1074200600 Tariff Record Parent Identifier: 4
Proposed Date: 2011-03-31
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NEW ENGLAND POWER COMPANY

Schedule II-A

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Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Schedule II-B, Schedule II-B, 0.0.0, A
Record Narative Name:
Tariff Record ID: 8
Tariff Record Collation Value: 1074200800   Tariff Record Parent Identifier: 4
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
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NEW ENGLAND POWER COMPANY

Schedule II-B

NEW ENGLAND POWER COMPANY
Primary Service for Resale
Rate W-95(N)

Demand Charge:	$17.17 per month for each kilowatt of Demand.
Energy Charge:	21.83 mills ($0.02183) for each kilowatt-hour of electricity delivered, except for kilowatt-hours of electricity delivered under Service for Resale to Interruptible Customers, Schedule III-C.
Interruptible Service: Charge	For each kilowatt-hour delivered in any hour pursuant to Schedule III-C, the amount specified for that hour by the Company pursuant to Paragraph C of Schedule III-C
Fuel and Purchased Economic Power Adjustment Clause:	For any month for which the Cost of Fuel is greater or less than 14.0000 mills per kilowatt-hour, the Energy Charge shall be increased or decreased respectively by the applicable fuel adjustment rate per kilowatt-hour delivered, which rate shall be equal to the difference of:

$$\frac{Fm}{Sm} - \frac{Fb}{Sb}$$

Where F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and “S” is the kilowatt-hour sales in the base and current periods, all as defined in Section 35.14 of the Regulations under the Federal Power Act as provided in Order No. 352 issued December 7, 1983 in Docket No. RM83-62-000. F shall also include expenses associated with purchases of electricity from alternate energy suppliers, provided however that payments from such suppliers due to their failure to perform or pursuant to contractual security provisions shall be credited to F above. F shall be credited with the revenues from sales for resale to interruptible customers pursuant to Schedule III-C and such sales shall be excluded from S.

As a signatory to the NEPOOL Agreement, dated as of September 1, 1971, as amended, the Company’s reserve capacity criteria is determined as a part of the NEPOOL reserve requirement. This type of interconnected pool operation avoids the need for member companies to individually determine reserve capacity criteria, while preserving individual company integrity through the basic NEPOOL Agreement. Each member utility’s commitment to the Pool’s requirements is assured by a monthly assessment of each members “Capability Responsibility”, as defined in the NEPOOL Agreement. See also the NEPOOL Agreement, FERC Rate Schedule No. 210. In determining whether a purchase is a reliability purchase, the Company will use its then-applicable NEPOOL reserve requirement, regardless of whether the selling utility is a member of NEPOOL. In the event that a short term operating reserve purchase is made by NEPOOL and an assessable share is billed to NEP, NEP will include in this clause only the cost of fuel associated with such purchase. Part of the costs in evaluating the interchange with NEPEX (the NEPOOL dispatching agency) may initially be estimated. All energy savings shares that are created in the NEPEX dispatch are reflected in fuel costs. The value of the estimated costs will be combined with the value of the actual costs for the billing month to determine the monthly fuel clause factor. Any difference between the actual and estimated data for a billing month will be reflected in cost data utilized in the calculation for the succeeding month.

Notwithstanding the above, whenever the foregoing determination would be affected by energy produced from generating units under construction as they undergo operational tests prior to their in service dates, the components of F shall be adjusted so that its value is the same as it would have been if such test energy were not available. Such adjustment to F in the formula shall also recognize that current wholesale customers have paid a part of the cost of generating units under construction through demand charges reflecting CWIP in rate base; therefore, a credit to F shall be applied equal to the differential between the cost of test energy and the displaced cost of fuel in the ratio that demand contributions for such units bear to the carrying cost of such units.

In addition to the foregoing, F shall also include fifty percent (50%) of all natural gas transportation demand charges incurred for the period beginning November 1, 1991 and ending on the sooner to occur of January 1, 1996 or the conclusion of the construction period for the Manchester Street Station repowering project, provided, however, that revenues received from third parties related to their use of NEP's pipeline capacity during the foregoing period shall be credited to F above. Thereafter, all natural gas transportation demand charges incurred shall be included in F above.

Once each calendar year, NEP shall reconcile the total incremental fuel costs of all short-term unit sales transactions, and sales pursuant to Schedule III-C, to fuel revenue from these transactions. If the total incremental fuel cost exceeds the fuel revenue, F shall be credited with the differential. The reconciliations shall be done in accordance with the procedures set forth in Dockets 92-372-000 et al. (unit power contracts) and Docket No. 94-1056-000 (Schedule III-C sales).

In accordance with a Surcharge Compliance Filing Settlement Agreement filed in Docket Nos. ER88-630-000, et al., a monthly charge for fuel expense underrecovery will be assessed all Customers except Massachusetts Electric Company, as shown at Appendix C to that Settlement Agreement. The foregoing charge will become effective as approved by the Commission and will continue thereafter for a period of ten (10) years, provided that if any of these

Customers terminates service from NEP prior to the conclusion of the amortization period, that Customer shall pay its remaining unamortized fuel expense upon the date it terminates service. The monthly charge will be: Narragansett Electric - $48,889, Granite State - $6,499, Groveland - $225, Merrimac - $196, Littleton - $535, Norwood - $3,128, N.H. Elec. Coop - $66, GMP - $52, and Ft. Devens - $540.

In accordance with the settlement of Docket No. FA91-53-000, F shall also include the 1.5% NEPEX differential billed to NEP by Central Maine Power for the use of low sulphur oil in the Wyman Units 1, 2, and 3 when Wyman 4 is operating.

Standard Delivery Point: For purposes of this Tariff, the "Standard Delivery Point" shall be considered to be that point on the integrated generating and transmission system of the Company that first follows one transformation from the power supply system or, by agreement of the parties, a point in close proximity thereto.

Metering Adjustments: Where delivery is metered at the Company's supply line voltage, in no case less than 69,000 volts, thereby saving the Company transformer losses then, before determining the number of kilowatts and kilowatt-hours to be billed under the preceding provisions, there shall be deducted from the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one percent (1.0%) of such registrations. Where delivery is metered at the sub-transmission voltage, or at the low side terminals of the transformation from the sub-transmission to the distribution of the customer, and not at the low side terminals of the transformation from the Company's supply line, there shall be added to the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one and one half percent (1.5%) of such registrations.

Transformer Ownership Credit: If delivery is made at the Company's supply line voltage, not less than 69,000 volts, and the Company is saved the cost of installing any transformer and associated equipment there will be allowed a credit of thirty cents ($0.30) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. In accordance with a Settlement Agreement in Docket Nos. ER91-565-000, et al., the credit applicable to the Town of Norwood will be twenty-one cents ($0.21) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. The foregoing credits, as applicable, shall be computed after the applicable Metering Adjustments.

Credit for EPRI Contributions:	A credit of six cents ($0.06) per kilowatt of the demand component will be allowed to all customers served under this schedule with the exception of the Company's affiliated customers (Massachusetts Electric Company, Narragansett Electric Company and Granite State Electric Company) in order to reflect the Company's commitment to research support of the Electric Power Research Institute (EPRI) unless a customer notifies the Company in writing that it desires to contribute through the Company's commitment, in which event this credit shall not apply to such Customer. In accordance with a Settlement Agreement in Docket Nos. ER91-565, et al., the credit applicable to the Town of Norwood will be nine cents ($0.09) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. These credits shall be computed after the application of any applicable Metering Adjustments and at the point of delivery which enters into the computation of the Customer's Demand for the month in question.

Norwood Yankee:	In accordance with the terms of the W-12 Settlement Amendment
Surcharge:	dated December 17, 1992 in Docket No. ER90-525 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with that settlement.
Norwood Seabrook 1 Amortization Surcharge:	In accordance with the terms of the W-95(N) Settlement dated June 30, 1995 in Docket No. ER95-267 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with section 2.2(b) of that settlement.

The Company reserves the right to amend the foregoing rate in the manner set forth in its General Terms and Conditions governing primary service for resale in Schedule I.

Effective Date: July 12, 1995

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Schedule II-C, Schedule II-C, 0.0.0, A
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Tariff Record Collation Value: 1074201000 Tariff Record Parent Identifier: 4
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NEW ENGLAND POWER COMPANY

Primary Service for Resale

DETERMINATION OF CONTRACT TERMINATION CHARGE
UNDER EARLY TERMINATION PROVISION

A. Applicability

The terms and conditions of this Schedule II-C are applicable to any eligible all-requirements wholesale customer (“Customer”) of New England Power Company

("Company") under this tariff which elects the early termination option under Schedule I, Section N of this tariff.

B. Determination of Contract Termination Charge

If a Customer exercises the early termination option under Schedule I, Section N, paragraph 2, of this tariff, the Customer shall pay the Company a Contract Termination Charge ("CTC") as determined under this schedule. The CTC shall be determined as follows:

$$CTC = (R - M) \times L$$

where:

R	=	the Customer's Annual Average Revenue, as determined in Section 1 below;
M	=	the Estimated Market Value of the Customer's released capacity and associated energy, as determined under Section 2 below;
L	=	the Length of Obligation in years, as determined under Section 3 below;

Payment of the CTC by the Customer shall be in accordance with Schedule I, Section N, paragraph 2, of this tariff.

The CRC shall be determined on a net present value basis, with the difference between R and M discounted to the Early Termination Date as defined in Section 3 below. The discount rate used shall equal the rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. § 35.19a) effective on the Early Termination Date.

In no event shall the CTC exceed the amount determined under section 4 below.

1. R - Average Annual Revenue

The Customer's Annual Average Revenue shall equal the Total Revenue minus the Transmission Revenue.

a. *Total Revenue* shall equal the annual average of revenues received by the Company from the Customer over three years under the presently effective rates as shown on Schedule II-A and Schedule II-B of this tariff. The three-year period shall be the 36 months immediately prior to the Early Termination Date as specified by the Customer under the second paragraph of Schedule I, Section N of this tariff. In the event that the rates paid by the Customer under Schedule II-A or Schedule II-B of this tariff have changed during the three-year period, Total Revenue shall be determined using the Customer's revenue for the 12 months immediately prior to the Early Termination Date. The Company at its discretion may use estimates of the Customer's billing units for determining Total Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date. The calculation of Total Revenue shall include credits pursuant to Schedule III-D of this tariff as well as all credits and surcharges applicable to the Customer under the Customer's Service Agreement with the Company under this tariff, with the exception of credits associated with Integrated Facilities arrangements under Schedule III-B of this tariff and any credits associated with the Company's reimbursement of the Customer's payments to third parties for transmission service.

b. *Transmission Revenue* shall equal the sum of: (i) the annual average of revenues the Company credited to the Customer with respect to payments made by the Customer to third parties for transmission service pursuant to any applicable provision of the service agreement between the Company and the Customer; or (ii) if the service agreement does not provide for such credits, the annual average of revenues the Company would have received from the Customer using the presently effective rates under the Company's Open Access Transmission Tariff, FERC Electric Tariff Original Volume No. 9 ("Tariff No. 9"); and (iii) the annual average of payments made by the Company to the New England Power Pool ("NEPOOL") for transmission service on the Customer's behalf under NEPOOL's Open Access Transmission Tariff, all as determined during the period over which the Total Revenue is determined. The Company at its discretion may use estimates of the Customer's billing units for determining Transmission Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date.

2. M - Estimated Market Value

The Estimated Market Value shall equal the annual average of the Market Price Estimate for each year of the Length of Obligation (as determined pursuant to Section 3 below) multiplied by the Customer's Released Load.

a. *Market Price Estimate* shall equal the per kilowatt-hour amount set forth in the Table below, as in effect on the Early Termination Date, as applicable to each year during the Length of Obligation. The Market Price Estimate shall include both a capacity-related and energy-related component.

Year	Capacity (¢/kWh) (¢/kWh)	Energy (¢/kWh)	Total
1998	1.10	2.71	3.81
1999	1.22	2.64	3.86
2000	1.22	2.66	3.88
2001	1.25	2.61	3.86
2002	1.31	2.63	3.94
2003	1.34	2.71	4.05
2004	1.40	2.72	4.12
2005	1.44	2.77	4.21
2006	1.47	2.86	4.33
2007	1.53	2.95	4.48
2008 forward		prices for 2007 escalated at 2% annually	

b. *Released Load* shall equal the annual average of the

Customer's kilowatt-hour purchases from the Company for the period over which Total Revenue is determined. The Company at its discretion may use estimates of the Customer's kilowatt-hour purchases for determining Released Load, such estimates to be reconciled to actual purchases within six months after the Early Termination Date.

3. L - Length of Obligation

The Length of Obligation shall equal the time period between the Early Termination Date and the Regular Termination Date.

a. *Early Termination Date* shall be as determined under Schedule I, Section N, paragraph 2 of this tariff

b. *Regular Termination Date* shall be the date at which the Company or the Customer could have unilaterally terminated service under Schedule I, Section N, paragraph 1 of this tariff and any applicable provisions of the Customer's Service Agreement with the Company under this tariff.

4. Maximum Contract Termination Charge

In no event shall the difference between R and M (as determined in Sections 1 and 2 above) exceed the Customer's annual contribution to the Company's fixed power supply costs under this tariff. The Customer's annual contribution to the company's fixed power supply costs shall equal its Total Revenue minus Transmission Revenue minus the Company's Average Fuel Costs. Average Fuel Costs shall equal the annual average of revenues the Company recovered for its Cost of Fuel as defined in Schedule II-A of this tariff multiplied by the Customer's monthly kilowatt-hour purchases during the period over which Total Revenue is determined in Section 1 above.

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NEW ENGLAND POWER COMPANY

Schedule III-A

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Schedule III-B, Schedule III-B, 0.0.0, A
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Tariff Record ID: 12
Tariff Record Collation Value: 1074201400   Tariff Record Parent Identifier: 4
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NEW ENGLAND POWER COMPANY

Primary Service for Resale

TERMS AND CONDITIONS

governing

ALL-REQUIREMENTS SERVICE - INTEGRATED FACILITIES

Schedule III-B

A. Applicability

The terms and conditions set forth herein shall apply when the Service Agreement is between the Company and a Customer which is affiliated with the New England Power Company, and specifies All-Requirements Service - Integrated Facilities.

B. Integrated facilities: Obligations of the parties.

Recognizing that the generation and transmission facilities owned by the Company and the Customer are physically interconnected and can be operated to achieve maximum economy through integrated operation, the Customer and the Company agree as follows:

1. The Customer will operate and maintain its generating and transmission facilities
in accordance with standards fixed from time to time by the Company, and will make available to the Company the full capacity of such facilities to meet the load of the integrated generating and transmission system (consisting of the generating and transmission facilities owned by the Company and affiliated companies of the New England Power Company). The Company and the Customer may agree to exclude from the facilities made available as aforesaid any facilities deemed not to be necessary or feasible for integration, and such excluded facilities shall not be considered part of the integrated generating and transmission system as defined above.

2. The generating and transmission facilities of the Customer made available to the Company under paragraph 1 shall be subject to dispatch by the Company to meet the load of the integrated generating and transmission system, and the output of the Customer's generating units so dispatched shall be deemed to be for the account of the Company. The Customer will conform to maintenance schedules fixed by the Company to ensure maximum availability of capacity.

3. The Company and the customers whose facilities constitute a part of the integrated generating and transmission system will plan jointly for the future requirements of such system. The Customer agrees to make additions to and retirements of its generating and transmission facilities in accordance with schedules fixed from time to time by the Company.

4. In consideration of the foregoing, the Company assumes responsibility for the supply of the electrical requirements of the Customer from the integrated generating and transmission system, including transmission losses over such system, and agrees to credit the Customer for the use of its generating and transmission facilities, in accordance with the following provisions:

    a. The Company agrees to sell and the Customer agrees to buy, at the Company's effective rate for primary service for resale, the Customer's entire requirements of electricity for its own use and for resale within the Districts described in the Service Agreement, with the following exceptions: (1) electricity purchased by the Customer from commercial and industrial establishments located within any District of the Customer's service area and specified in the Service Agreement, (2) electricity purchased by the Customer under convenience contracts for the supply of electricity to borderline customers, and (3) such other exceptions as may be mutually agreed upon between the parties and set forth in the Service Agreement.

b. For Customer-owned Transmission Plant, the Company will credit each monthly bill rendered to the Customer using the calculation shown below based on the previous month's cost data from Customer's official books and records. Capitalized terms used in this calculation will have the following definitions:

1. Gross Transmission Plant Allocation Factor shall equal the ratio of Customer's Total Investment in Transmission Plant to Total Plant in Service, excluding General Plant.

2. PTF Allocation Factor shall equal the ratio of PTF Transmission Plant to Transmission Plant.

3. PTF-RSP Allocation Factor shall equal the ratio of PTF-RSP Transmission Plant to Transmission Plant.

4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct electric wages and salaries from Customer to Customer's total electric direct wages and salaries and excluding electric administrative and general wages and salaries.

5. Administrative and General Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 920-935, less Post Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, plus the FERC-accepted Post Employment Benefit Other than Pensions identified in each Customer’s Service Agreement or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

6. Amortization of Investment Tax Credits shall equal Customer's electric credits as recorded in FERC Account No. 411.4.

7. Amortization of Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account No. 428.1.

8. Depreciation Expense for Transmission Plant shall equal Customer's electric transmission plant related depreciation expenses as recorded in FERC Account No. 403 calculated

using the depreciation rates set forth in each Customer's Service Agreement.

9. General Plant shall equal Customer's electric gross general plant balance as recorded in FERC Account Nos. 389-399.

10. General Plant Depreciation Expense shall equal Customer's electric general plant related depreciation expenses as recorded in FERC Account No. 403.

11. General Plant Depreciation Reserve shall equal Customer's electric general plant depreciation reserve balance as recorded in FERC Account No. 108.

12. Municipal Tax Expenses shall equal Customer's electric transmission-related municipal tax expense as recorded in FERC Account No. 408.1.

13. Payroll Taxes shall equal those electric payroll tax expenses as recorded in Customer's FERC Account Nos. 408.1.

14. Land Held for Future Use shall equal the Customer's electric transmission-related balance for Land in FERC Account No. 105.

15. Prepayments shall equal Customer's electric prepayment balance as recorded in FERC Account No. 165.

16. PTF-RSP Transmission Plant shall equal any PTF Transmission Plant as defined below and approved as part of the ISO-NE Regional System Plan.

17. PTF Transmission Plant shall equal electric transmission plant as defined in Section II.49 of the ISO-NE OATT and determined in accordance with Appendix A of Attachment F Implementation Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

18. Total Accumulated Deferred Income Taxes shall equal the net of Customer's electric deferred tax balance as recorded in FERC Account Nos. 281-283 and Customer's electric deferred tax balance as recorded in FERC Account No. 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory

assets or liabilities.

19. Total Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account 189.

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

21. Total Transmission Depreciation Reserve shall equal Customer's electric transmission plant related depreciation reserve balance as recorded in FERC Account 108.

22. Transmission Operation and Maintenance Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 560-564 and 566-573 less any expenses recorded in FERC Account 561.4.

23. Transmission Plant shall equal Customer's electric gross plant balance as recorded in FERC Account Nos. 350-359.

24. Transmission Plant Materials and Supplies shall equal Customer's electric materials and supplies balance as recorded in FERC Account No. 154

25. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided which is not specifically identified under any other section contained herein.

In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

Calculation of Transmission Revenue Requirements

The monthly Transmission Revenue Requirement shall equal the sum of Customer's (A) Return and Associated Income Taxes (including the Incremental Returns for PTF-RSP and PTF Investment), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Distribution, Credit, (J) Transmission Related Taxes and Fees Charge, (K) Billing Adjustments, and (L) Annual True-Up Adjustment. The Incremental Return and Associated Income Taxes for PTF-RSP and PTF Investments shall be calculated using the investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of each of the Transmission Investment Base (PTF-RSP, PTF and Non-PTF, respectively) and the Cost of Capital Rates applicable to each.

1. Transmission Investment Base

(a) Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.

(i) PTF-RSP Investment Base will be the monthly balances of PTF-RSP Transmission Plant, less the sum of (d) Transmission Related Depreciation Reserve and (e) Transmission Related Accumulated Deferred Income Taxes, multiplied by the PTF-RSP Allocation Factor.

(ii) PTF Transmission Investment Base will be the monthly balances of PTF Transmission Plant, less PTF-RSP Investment Base, plus the product of: PTF Allocation Factor multiplied by the sum of the [(b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Income Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital].

(iii) Non-PTF Transmission Investment Base shall equal Total Transmission Investment Base less PTF-RSP Investment Base less PTF Investment Base.

(b) Transmission Related General Plant shall equal Customer's balance of investment in electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.

(c) Transmission Land Held for Future Use shall equal Customer's balance of electric Transmission-related Land Held for Future Use.

(d) Transmission Related Construction Work In Progress shall equal the portion of Customer's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.

(e) Transmission Related Depreciation Reserve shall equal Customer's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.

(f) Transmission Related Accumulated Deferred Income Taxes shall equal Customer's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Gross Transmission Plant Allocation Factor.

(g) Transmission Related Loss on Reacquired Debt shall equal Customer's electric balance of Total Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

(h) Transmission Prepayments shall equal Customer's electric balance of prepayments multiplied by the Gross Transmission Plant Allocation Factor.

(i) Transmission Materials and Supplies shall equal Customer's electric balance of Transmission Plant Materials and Supplies, multiplied by the Gross Transmission Plant Allocation Factor.

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Customer's Transmission Operation and Maintenance Expense (less FERC Account 565: Transmission of Electricity by Others) and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will incorporate Customer's imputed capital structure, Customer's actual cost of long-term debt and preferred equity, and approved ROEs for Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively), plus Federal Income Tax.

(a) The Weighted Costs of Capital will be calculated for each of the Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively) based upon the imputed capital structure for Customer in place in accordance with Rhode Island Docket Nos. 2930 and 3617 and will equal the sum of (i), (ii), and each ROE applied in item (iii) below.

(i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45%.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Customer's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5%.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs applicable to the corresponding investments below and the Customer's imputed common equity capitalization ratio of 50%.:

12.64% - Post-2003 to pre-2009 PTF transmission plant investment included in the Regional System Plan approved by ISO-NE.

11.64% - The remaining PTF transmission plan investment.

11.14% - The remaining transmission plant investment.

As per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679. To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

(b) Federal Income Tax applied shall equal

$$(PS + ROE) \quad X \quad \frac{\text{Federal Income Tax Rate}}{\text{(1- Federal Income Tax Rate)}}$$

where PS is the Preferred Stock Component and ROE is the return on equity component, each as determined in Sections

2.(a)(ii) and for the applied ROEs set forth in 2.(a)(iii) above.

B. Transmission Depreciation Expense shall equal Customer's electric Depreciation Expense for Transmission Plant, plus an allocation of electric General Plant Depreciation Expense calculated by multiplying electric General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Customer's electric Amortization of Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal Customer's electric Amortization of Investment Tax Credits multiplied by the Gross Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal Customer's transmission-related electric municipal tax expense.

F. Transmission Related Payroll Tax Expense shall equal Customer's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.

G. Transmission Operation and Maintenance Expense shall equal Customer's total electric Transmission Operation and Maintenance Expenses.

H. Transmission Related Administrative and General Expenses shall equal the sum of Customer's electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.

I. Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.

J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this section, including, but not limited to, expenses incurred by the Customer related to third party independent audits conducted at the request of any governmental authority, and any other fee or assessment which is not specifically identified under any other section contained herein. Such costs will be separately identified and included in item H - Administrative and General Expense, above.

K. Billing Adjustments shall be plus or minus any billing adjustments from the prior
transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.

L. Annual True-Up Adjustment

1. NEP shall submit an annual informational filing with the FERC with copies to state commissions and attorneys general in the state of any affected Customer reconciling monthly billings to Customer under this formula to data supplied from Customer's Quarterly FERC Form 1 (the "Annual True- up"). The Annual True-up will be completed no later than (3) months after Customer issues its final 4th Quarter FERC Form 1 for the calendar year which the Annual True-up relates (the "Service Year"). The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form l's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

2. The difference, if any, between the monthly actual costs invoiced to Customer during the Service Year and the annual revenue requirement based on actual FERC Form 1 data shall be reflected as an adjustment to the monthly revenue requirement calculation for the month following the month in which the Annual True-Up report is issued (the "Annual True-up Adjustment").

3. If the recalculation of costs for the Service Year using FERC Form 1 data exceeds the monthly billed amounts for the Service Year, the Annual True-up Adjustment will be an additional credit to Customer. If the monthly billed amounts for the Service Year exceed the recalculation of costs using FERC Form 1, the Annual True-up Adjustment will be a reduction to the credit to Customer. The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the

Commission's regulations 18 C.F.R §35.19a.

4. Any changes to the data inputs, including but not limited to revisions to Customer's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-up, or as a result of the procedures set forth herein not otherwise captured as part of ongoing Billing Adjustments, shall be incorporated into the formula rate and the charges produced by the formula rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual True-up for the next effective rate period.

5. In any proceeding before the FERC concerning the Annual True-up, the Company shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

M. Five-Year Forecast

The Company’s annual informational filing will also provide a report containing a five year forecast of anticipated transmission capital expenditures by the Company and its Customers taking service under this Tariff that will, upon completion of projects, be included in transmission rates. The forecast will also include the estimated retail rate impacts for each of the Company’s respective Customers under this Schedule III-B.

N. Audit Provisions

1. There will be an “Audit Period” that will extend from the date the informational filing is filed with FERC through December 31 of the year following the Service Year. At any time during the Audit Period, a Customer shall have the right to request an audit or conduct an inspection of the actual data used in the Annual True-Up and any and all transmission charges or credits billed by Company during the Service Year. Subject to the limitation that the Attorneys General of Massachusetts and Rhode Island do not make or receive transmission payments or refunds, they shall have the same procedural rights under this Section as a Customer. Company shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel as prescribed by FERC. Company is not obligated to disclose privileged information or information protected by the attorney work product doctrine. Company shall

exercise all commercially reasonable efforts to provide Customer, within 10 business days, such additional information as Customer may reasonably request. To the extent requested, Company shall meet with any Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up or any other information related to Customer billing under this Tariff during the Service Year. During the Audit Period any Customer may request that Company adjust the Annual True-up Adjustment and/or Customer bills rendered during the Service Year. Any adjustment that Company agrees to make may be reflected in the next month following such adjustment. Upon request of any Customer during the Audit Period, Company shall engage a third party independent auditor (the "Auditing Entity") through the process described in Paragraph 4, below. The Auditing Entity shall certify that the development, accuracy and application of data, is in accordance with the provisions of this Tariff. The Auditing Entity shall provide a Certified Public Accountant's attestation setting forth such certification ("CPA Attestation").

2. In addition to the CPA Attestation, the Auditing Entity will provide an audit report that will specify the audit process and procedures; identify the individual auditors and their functions; and include all copies of all written communications with Company personnel, summaries of all other communications related to the audit, descriptions of all data analysis techniques used, findings and recommendations. Also, the Auditing Entity shall make available all workpapers and other documentation and materials that support the CPA Attestation.

3. Company shall engage the Auditing Entity to perform the CPA Attestation duties through a competitive bidding process, evaluating each bidder according to cost, experience, competency and familiarity with the industry and the regulatory environment. The requesting Customer(s) shall have the right to approve the content of the Request for Proposal and Company's selection of the auditing entity, which approval shall not be unreasonably withheld. If necessary, and after good faith efforts have not resulted in the Company's obtaining an Auditing Entity to provide the CPA Attestation pursuant to this Paragraph 4, the requesting Customer(s) and the Company agree to negotiate in good faith the scope of work that may be needed to provide a CPA Attestation and to accommodate the American Institute of Certified Public Accountants Code of Professional Conduct.

4. In the event an independent audit is performed with respect to a Service Year and the Company determines that the Annual True-

Up is incorrect, the Annual True-Up required by Paragraph L of this Tariff may be subsequently adjusted pursuant to the provisions of this Tariff.

5. The reasonable and prudent cost of the Auditing Entity's services and Company's reasonable and prudent costs of engaging the Auditing Entity and providing information to the Auditing Entity and the Customer shall be included as part of the transmission costs charged to the Customers under this Tariff.

Formula rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission.

application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expense under the formula rate shall not open review of other components of the formula rate.

Calculation of Primary Distribution Revenue Requirements

For Customer-owned distribution facilities utilized by the Company for purposes of providing wholesale transmission service, effective as of the June billing month of each year , the Company will credit each monthly bill rendered to the Customer with one-twelfth of the annual costs determined by multiplying the sum of the applicable Customer's: (i) Distribution Plant Assets; (ii) Shared Substation Assets, and; (iii) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Primary Distribution Carrying Charge based upon previous calendar year data. The Primary Distribution Carrying Charge shall be calculated as follows for the applicable Customer:

I. The Primary Distribution System Carrying Charge shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit, divided by Total Primary Distribution Plant.

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

1. Primary Investment Base will be (a) Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Primary Materials and Supplies, plus (h) Primary Related Prepayments, plus (i) Primary Related Cash Working Capital.

a) Primary Distribution Plant shall equal the Customer's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Allocation Study.

b) Primary Related General Plant shall equal the Customer's Investment in General Plant excluding investment in specific buildings and facilities allocated to Company, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total Customer's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

c) Primary Plant Held for Future Use shall equal the Customer's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Allocation Study.

d) Primary Depreciation Reserve shall equal the Customer's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above,

e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

g) Primary Materials and Supplies shall equal the Customer's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

h) Primary Related Prepayments shall equal the Customer's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

i) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

2. Cost of Capital Rate will equal (a) the Customer's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (e) 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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of the Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the Customer's preferred stock then outstanding and the Imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE), shall be the product of the allowed ROEs shall be 11.14% as per FERC's Order on Rehearing Issued on March 24, 2008-in FERC Docket Nos. ER04-157-004 and ER04-714-001 and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679.[1] To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

A x FT

1-FT

where FT is the Federal Income Tax Rate and A the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \times ST}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (l)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is Federal Income Tax as determined in Section (1)(A)(2)(b) above.

B. Primary Depreciation Expense shall equal Customer's electric distribution-related depreciation expense as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(l)(b) above.

C. Primary Related Amortization of Loss on Reacquired Debt shall equal the Customer's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

D. Primary Related Amortization of Investment Tax Credits shall equal the Customer's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(I)(e) above.

E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the Customer's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

F. Primary Operation and Maintenance Expense shall the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Allocation Study.

G. Primary Related Administrative and General Expenses shall equal the Customer's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.

H. Primary Related Revenue Credit shall equal Customer's Other Operating Revenues excluding any revenues from network distribution transactions, multiplied by the Primary O&M Allocation Factor as defined in (I)(A)(1)(b).

For Company-owned facilities utilized by the Customer for purposes of providing retail distribution service, effective as of the June billing month of each year, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual costs determined by multiplying the sum of the Company's: (i) Transmission Assets (ii) Distribution Plant Assets; (iii) Shared Substation Assets, and; (iv) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Annual Facilities Carrying Charge for Transmission Facilities - based upon previous calendar year data. In addition, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual cost for pole and tower attachments. The Annual Facilities Charge for Transmission Facilities shall be calculated as follows:

1. The Annual Facilities Carrying Charge for Transmission Facilities shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D)Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Operation and Maintenance Expense, and (G) Transmission Related Administrative and General Expenses, divided by Total Transmission Plant.

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

1. **Transmission Investment Base** will be (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Income Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Materials and Supplies, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Related Prepayments, plus (k) Transmission Related Cash Working Capital.

a) **Transmission Plant** shall equal NEP’s balance of Total Investment in Transmission Plant in FERC Accounts 350 - 359, plus NEP’s Total Investment in Distribution Plant in FERC Accounts 360-369 excluding NEP’s capital leases in the Hydro-Quebec DC facilities (HQ leases).

b) **Transmission Related General Plant** shall equal NEP’s balance of investment in General Plant in FERC Accounts 389 to 399 excluding General Plant related to NEP’s generation facilities.

c) **Transmission Plant Held for Future Use** shall equal the balance of investment in FERC account 105 excluding generation-related plant held for future use.

d) **Transmission Related Construction Work in Progress** shall equal the portion of NEP’s investment in Transmission related projects as recorded in FERC Account 107 consistent with Commission Orders.

e) **Transmission Related Depreciation Reserve** shall equal the balance of Total Depreciation Reserve in FERC Account 108, excluding any generation-related depreciation reserve.

f) **Transmission Related Accumulated Deferred Income Taxes** shall equal the net of NEP's Total Accumulated Deferred Income Taxes in FERC Accounts 281-283 and FERC Account 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities. and any Accumulated Deferred Taxes associated with non-utility assets or generation facilities.

g) **Transmission Related Loss on Reacquired Debt** shall equal NEP's balance of Total Loss on Reacquired Debt in FERC Account 189.

h) **Transmission Related Materials and Supplies** shall equal NEP's balance of Materials and Supplies in FERC Account 154.

i) **AFUDC Regulatory Liability** shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission Orders.

j) **Transmission Related Prepayments** shall equal NEP's balance of prepayments in FERC Account 165 excluding any prepayments related to NEP's ongoing generation-related activities.

k) **Transmission Related Cash Working Capital** shall be 12.5% allowance (45 days/360) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. **Cost of Capital Rate**

The Cost of Capital Rate shall equal (a) NEP'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:

(1) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of NEP's long-term debt then outstanding

and the imputed long-term debt capitalization ratio of 45 percent.

(2) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5 percent.

(3) the return on equity component (ROE) shall be the product of 11.14% as per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and NEP's imputed common equity capitalization ratio of 50%, To the extent FERC modifies ROEs as applicable to transmission assets, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to the filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \text{ X } FT}{1\text{-}FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)()2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \text{ x } ST}{1 - ST}$$

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and the Federal Income Tax is Federal Income Tax as determined in Section (I)(A)(2)(b) above.

B. **Transmission Related Depreciation Expense** shall equal the Depreciation Expense in FERC Account 403 associated with Transmission Plant, Transmission Related General Plant and Transmission Plant Held for Future Use as described in Sections (I)(A)(1)(a), (b) and (c), less the amortization of AFUDC Regulatory Liability as recorded in FERC Account 407.3.

C. **Transmission Related Amortization of Loss on Reacquired Debt** shall equal NEP's amortization of the balance on Loss on Reacquired Debt recorded in FERC Account 428.1.

D. **Transmission Related Amortization of Investment Tax Credits** shall equal the amortization of Investment Tax Credits recorded in FERC Account 411.4, excluding any ITC credits specifically identified as generation-related.

E. **Transmission Related Municipal Tax Expense** shall equal NEP's total municipal tax expense recorded in FERC Account 408.1 excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.

F. **Transmission Operation and Maintenance Expense** shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems.

G. **Transmission Related Administrative and General Expenses** shall equal NEP's Administrative and General Expenses recorded in FERC Accounts 920-935, less production-related Administrative and General Expenses associated with joint-owned production units, plus Payroll Taxes.

The Company's rate for tower attachments is $49.28 per tower. The Company's rate for pole attachments is $253.27 per pole. The annual cost for the Customer to attach to the Company's towers and poles will be the product of the respective rate multiplied by the number of respective attachments as specified in the Customer's Service Agreement.

The Customer shall afford to the Company the opportunity at any time to make such reasonable examination of the Customer's books and records as the Company may request for the purpose of verifying the basis for calculation of the foregoing monthly credits.

The foregoing credits shall be reviewed annually and upon substantial addition, modification or retirement of the Customer's generating and transmission facilities or other substantial change in circumstances, any changes therein shall be reflected in a revised Service Agreement.

C.

If the Service Agreement is amended by mutual consent of the parties, the terms of the agreement as so amended shall be applicable to the Customer's service on and after the effective date specified therein. If no such amendment has been executed prior to the date specified in the Customer's notice, the Customer may at its election terminate the Service Agreement forthwith or upon such date within the following twelve months as it may specify to the Company in writing.

D. Amendments.

The Company reserves the right to amend the foregoing terms and conditions in the manner set forth in its General Terms and Conditions governing primary service for resale.

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Schedule III-C, Schedule III-C, 0.0.0, A
Record Narative Name:
Tariff Record ID: 13
Tariff Record Collation Value: 1074201600 Tariff Record Parent Identifier: 4
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

NEW ENGLAND POWER COMPANY

Schedule III-C

THIS SECTION INTENTIONALLY LEFT BLANK

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Schedule IV, Schedule IV, 0.0.0, A
Record Narative Name:
Tariff Record ID: 14
Tariff Record Collation Value: 1074201800 Tariff Record Parent Identifier: 4
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

FORM OF SERVICE AGREEMENT

Dated:

Parties: NEW ENGLAND POWER COMPANY

A Massachusetts corporation (the “Company”)

20 Turnpike Road
Westborough, Massachusetts 01581

and

(the “Customer”)

1. <u>Scope of Service Agreement.</u> The Company agrees to sell and transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I	- General Terms and Conditions
Schedule II	- Rate Provisions
Schedule III	- Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. <u>Prior agreements.</u> As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By ______________________________
Vice-President

APPENDIX A

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:

2. Name of District:

3. Service Under:

4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)

5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement:

   (Schedule I - Paragraph D)

6. Variations from Standard Delivery and Metering:

   (Schedule I - Paragraph G, 5)

7. Entitlements:

   A. On Customer System

      (Schedule III-C - Paragraph C.2.(a))

B. Off Customer System

(Schedule III-C - Paragraph

C.2.(b))

8. Customer Generation excluded

from Firm Capacity Calculation:

(Schedule III-C - Paragraph C.3.c)

9. Firm Capacity:

(Schedule III-C - Paragraph C.3.c)

10. Integrated Generating,

Transmission and Facilities

Credits Payable by Company:

(Schedule III-B - Paragraph B.4.b)

11. Primary Service for Resale:

Delivery Delivery Points	Delivery Pressure KV (Nominal) Adjustments	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments

12. Minimum Demand KW: None

13. Minimum Term: None

14. Transmission Service for Partial Requirements Customers:

Transmission Delivery Point(s)	KV (Nominal) (Nominal)	Subtransmission Delivery Point(s)	KV

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
MECO and NECO SA, New England Power Service Agreement No. 20, 0.0.0, A
Record Narative Name:
Tariff Record ID: 15
Tariff Record Collation Value: 1075256000 Tariff Record Parent Identifier: 0
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

SERVICE AGREEMENT

Between

NEW ENGLAND POWER COMPANY

And

MASSACHUSETTS ELECTRIC COMPANY

And

NANTUCKET ELECTRIC COMPANY

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

Dated: February 15, 1974

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the "Company")

and

MASSACHUSETTS ELECTRIC COMPANY and
NANTUCKET ELECTRIC COMPANY
Massachusetts corporations (the "Customer")

1. Scope of Service Agreement. The Company agrees to transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I - General Terms and Conditions

Schedule II - Rate Provisions

Schedule III - Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

NONE

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By: ________________________________

MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY

By: ________________________________

NEW ENGLAND POWER COMPANY

Primary Service for Resale and Transmission Service for Partial Requirements Customers

1. Name of Customer:	Massachusetts Electric Company, Nantucket Electric Company
2. Name of District:	Baystate West, Baystate South, and North and Granite
3. Service Under:	Schedules III-B of the Tariff and Settlements accepted by the Commission in Docket Nos. ER97-678-000, ER97-2800-000, and ER10-523-000.
4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	The Naragansett Electric Company, Western Mass Electric Company Hingham Municipal Lighting Plant, Boston Edison
5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Not Applicable. Mass Electric no longer takes generation service under Tariff No. 1. Contract Termination Charge provided pursuant to Contract Termination Charge Amendment
6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)	Not applicable
7. Entitlements:	
A. On Customer System (Schedule III-C Paragraph C.2.(a))	None
B. Off Customer System (Schedule III-C Paragraph C.2.(b))	None

8. Customer Generation excluded from Firm Capacity Calculation: (Schedule III-C - Paragraph C.3.c) None

9. Firm Capacity: (Schedule III-C - Paragraph C.3.c) None

10. Integrated Generating, Transmission and Facilities Credits - Schedule III-B: Company and Customer acknowledge that the formula rates and Company's billings to Customer under Schedule III-B shall be subject to and shall comply with the terms and conditions of the Uncontested Settlement Agreement approved by the FERC in FERC Docket No. ER10-523-000 (Settlement), *New England Power Company*, [ ].

    (Schedule III-B - Paragraph B.4.b)

Payable by Company:

Customer Distribution Plant Assets Serving Wholesale Transmission Function:	Attachment 1	$4, 741, 264
Customer Shared Substation Assets:	Attachment 2	$2,365,249
Customer Buildings and Facilities	Attachment 3	$2,141,768

Payable by Customer:

Company Transmission Assets (13.8 and 23kV)	Attachment 4	$4, 075,372
Company Distribution Plant Assets	Attachment 5	$292,975
Company Shared Substation Assets:	Attachment 2	$8,190,969
Customer Attachments to Company Towers	Attachment 6	195
Customer Attachments to Company Poles	Attachment 6	858

Formula Rate Inputs:

1. Customer Post Retirement Benefits Other Than Pensions (PBOP) - ($18,300,000)

2. Customer Depreciation Rates

Transmission Accounts	**Rate**
352	1.56%
353	1.79%
354	1.54%
355	3.04%
356	2.49%

357	1.97%
358	-1.33%
359	0.27%

Distribution Accounts	**Rate**
361	2.44%
362	2.07%
364	3.41%
365	3.19%
366	2.56%
367.1	2.90%
368	
368.1	3.50%
368.2	3.77%
368.3	3.87%
369	
369.1	3.53%
369.20	2.90%
369.21	2.90%
369.22	0.00%
370	
370.1	4.23%
370.2	4.49%
370.3	4.10%
370.35	3.65%
371	0.00%
373	
373.1	5.44%
373.2	5.41%

General Accounts	**Rate**
390	2.05%
391	6.67%
392	6.67%
393	3.04%
394	5.59%
395	5.97%
396	6.67%
397	6.67%
397.1	3.83%
398	6.48%

11. Primary Service for Resale:	None. LNS transmission service is provided by New England Power Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP). Contract Termination Charge provided pursuant to Contract Termination Charge Amendment. Nothing contained herein is intended to modify or otherwise affect the settlements accepted by the Commission in Docket Nos. ER97-678-000 and ER97-2800-000. In the event of a conflict between the Contract Termination Charge Amendment and the settlements, the settlements shall govern.
12. Minimum Demand KW:	None
13. Minimum Term:	None
14. Transmission Service for Partial Requirements Customers:	LNS transmission service provided by New England Power Company (NEP) to Massachusetts Electric Company and Nantucket Electric Company under ISO-NE's Open Access Transmission Tariff (FERC Electric Tariff No. 3, Schedule 21-NEP.)

Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Attachments, Attachments to Service Agreement No. 20, 0.0.0, A
Record Narative Name:
Tariff Record ID: 16
Tariff Record Collation Value: 1075256200 Tariff Record Parent Identifier: 15
Proposed Date: 2011-03-31
Priority Order: 500
Record Change Type: NEW
Record Content Type: 2
Associated Filing Identifier:

This is a PDF section and we cannot render PDF in a RTF document.

Document Content(s)

Division 1-2

Request:

Please provide an explanation of the Integrated Facilities Agreement and the transactional relationship between NEP and The Narragansett Electric Company.

Response:

Narragansett Electric Company (NECO) owns transmission facilities in Rhode Island. Pursuant to the terms of the approved Integrated Facilities Agreement, NEP is the single National Grid subsidiary that provides integrated alternating current (AC) transmission service across New England. In this regard, NEP operates and controls National Grid's AC facilities used for wholesale transmission purposes - including those transmission facilities owned by NECO - as a single integrated system for the provision of open access transmission service in New England. Therefore, NEP's revenue requirement reflects the cost to compensate NECO for its transmission facilities cost-of-service pursuant to FERC-approved formula rate in Schedule III-B of NEP Tariff No. 1. NECO's transmission revenue requirement is recovered through both RNS and LNS rates, depending on the nature of the transmission facilities in question (i.e. Pool Transmission Facilities (PTF) or Non-PTF).

Prepared by or under the supervision of: James L. Loschiavo

Division 1-3

Request:

Please provide Work papers associated with the LNS rate increase.

Response:

Please see Attachment DIV 1-3.

Prepared by or under the supervision of: James L. Loschiavo

Narragansett Electric Company
NEP Non-PTF Revenue Requirement
2012 Forecast vs. 2011 Forecast

	2011											2010		
	January	February	March	April	May	June	July	August	September	October	November	December	Total	Incr/(Decr) 2012 vs. 2011
Return and Assoc. Income Taxes	$ 8,811,667	$ 8,943,066	$ 9,041,613	$ 9,135,722	$ 9,185,536	$ 9,313,279	$ 9,314,367	$ 9,437,749	$ 9,528,570	$ 9,375,286	$ 9,530,303	$ 8,783,805	$ 110,400,963	$ 6,806,754
Trans. Depreciation & Amort. Expense	2,832,209	2,848,837	2,866,411	2,884,662	2,899,627	2,903,680	2,908,331	2,924,716	2,937,835	2,939,286	2,979,250	2,819,426	34,744,268	2,276,848
Trans. Amort. of Loss on Reacq. Debt	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	16,884	24,441	285,735	(7,557)
Trans. Amort. of Investment Tax Credits	(33,001)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(32,905)	(33,008)	(395,057)	1,905
Trans. Amort. of FAS 109	384,246	384,246	384,246	384,246	401,748	401,748	396,138	396,138	396,138	396,138	396,138	384,246	4,705,416	196,638
Trans. Municipal Tax Expense	3,969,301	2,104,037	2,102,231	2,092,801	2,082,201	2,083,036	2,335,701	1,905,119	2,131,225	2,115,953	2,115,941	1,951,723	26,989,270	4,747,069
Trans. Operation and Maint. Expense	4,304,531	4,415,565	4,092,470	3,283,912	2,723,696	5,579,613	3,061,688	3,194,124	8,213,470	183,556	7,464,123	2,404,057	48,920,804	1,319,543
Trans. Admin. and General Expense	1,434,432	2,943,169	4,932,369	1,942,359	3,002,619	3,974,617	3,298,629	3,667,707	2,101,652	3,035,597	2,789,990	3,653,502	36,776,643	2,641,404
Trans. Integrated Facilities Credit (Expense)	4,727,982	4,898,143	5,470,007	5,096,949	5,574,417	6,406,582	5,000,870	6,120,160	8,105,382	4,905,485	8,695,508	4,282,124	69,283,609	17,837,399
Trans. Revenue Credit	(21,155,835)	(21,713,809)	(20,468,398)	(19,505,033)	(17,675,562)	(20,423,910)	(20,986,914)	(24,214,138)	(21,156,322)	(18,315,521)	(16,394,505)	(19,146,076)	(241,156,024)	3,637,033
Distribution Integrated Facilities Credit	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Adjustments	-	(306,082)	2,951	-	(227,661)	-	-	-	191,141	(2,137,365)	-	-	(2,477,016)	(604,966)
Reactive Power Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	$ 5,299,973	$ 4,508,708	$ 8,415,437	$ 5,307,153	$ 7,958,157	$ 10,230,181	$ 5,320,346	$ 3,423,111	$ 12,440,627	$ 2,489,951	$ 17,560,727	$ 5,124,240	$ 88,078,611	$ 38,852,070

	2010												
	January	February	March	April	May	June	July	August	September	October	November	December	Total
Return and Assoc. Income Taxes	$ 8,207,002	$ 8,306,145	$ 8,446,923	$ 8,537,888	$ 8,566,493	$ 8,673,695	$ 8,790,321	$ 8,830,675	$ 8,974,453	$ 9,025,562	$ 9,075,309	$ 8,159,743	$ 103,594,209
Trans. Depreciation & Amort. Expense	2,625,246	2,641,077	2,663,781	2,688,029	2,702,697	2,714,423	2,734,510	2,752,380	2,771,220	2,789,024	2,801,738	2,583,296	32,467,420
Trans. Amort. of Loss on Reacq. Debt	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	24,441	293,292
Trans. Amort. of Investment Tax Credits	(33,038)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,008)	(33,841)	(396,962)
Trans. Amort. of FAS 109	363,808	363,808	363,808	363,808	384,254	384,254	384,246	384,246	384,246	384,246	384,246	363,808	4,508,778
Trans. Municipal Tax Expense	2,868,495	1,766,401	1,494,090	1,749,739	2,227,004	1,752,775	1,758,178	1,770,932	1,759,037	1,765,732	1,766,850	1,562,968	22,242,201
Trans. Operation and Maint. Expense	3,643,766	3,951,404	3,467,939	3,768,535	3,085,327	4,619,672	4,338,315	5,044,396	4,346,876	4,537,275	3,149,069	3,648,687	47,601,261
Trans. Admin. and General Expense	2,193,854	2,901,888	3,491,255	2,724,315	2,487,136	3,228,106	3,196,417	2,364,192	3,017,498	3,214,223	2,384,532	2,931,822	34,135,239
Trans. Integrated Facilities Credit (Expense)	4,050,848	4,428,291	4,885,185	3,915,223	4,277,685	4,148,373	4,046,258	4,412,530	4,312,454	4,326,966	4,381,094	4,261,301	51,446,209
Trans. Revenue Credit	(14,032,461)	(14,974,909)	(19,082,200)	(17,957,471)	(16,266,687)	(21,702,533)	(24,541,672)	(27,087,300)	(25,448,864)	(25,772,302)	(19,910,027)	(18,016,630)	(244,793,057)
Distribution Integrated Facilities Credit	-	-	-	-	-	-	-	-	-	-	-	-	-
Billing Adjustments	(6,315,017)	-	-	-	(67,939)	-	(1,804,111)	-	-	-	-	6,315,017	(1,872,050)
Reactive Power Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
Bad Debt Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
	$ 3,596,944	$ 9,375,538	$ 5,722,213	$ 5,781,500	$ 7,387,404	$ 3,810,196	$(1,106,105)	$(1,536,517)	$ 108,352	$ 262,159	$ 4,024,245	$ 11,800,613	$ 49,226,541

SUMMARY

	2012 Frcst	2011 Frcst	Incr/(Decr)
Total RR per Monthly LNS	$88,078,611	$49,226,542	$38,852,069
Forecasted Capital Additions	$8,592,000	$5,120,000	$3,472,000
Total NEP Revenue Requirement	$96,670,611	$54,346,542	$42,324,069

	$42,324,069
Times Avg Ratio Share	25.76%
	$10,902,680 off $25,634
Expense Increase	$38,852,069
Times Avg Ratio Share	25.76%
	$10,008,293
Cap Adds	$3,472,000
Times Avg Ratio Share	25.76%
	$894,387

July-11 DRAFT

New England Power Transmission - In Service Forecast
For CY11- CY15
in $m

Calendar Year	Total	Est. PTF	Non-PTF
CY11	74.9	66.0	8.9
CY12	293.3	251.7	41.6
CY13	166.1	94.2	71.9
CY14	234.4	205.4	29.0
CY15	212.1	145.5	66.7
	980.9	**762.8**	**218.1**

Narragansett Electric - Transmission - In Service Forecast
For CY11- CY15
in $m

Calendar Year	Total	Est. PTF	Non-PTF
CY11	8.3	7.7	0.6
CY12	107.9	95.8	12.0
CY13	202.6	191.0	11.5
CY14	47.5	14.0	33.6
CY15	28.7	1.1	27.7
	395.0	**309.6**	**85.4**

NEP & Narragansett - Transmission - In Service Forecast
For CY11- CY15
in $m

Calendar Year	Total	Est PTF	Non-PTF
CY11	83.2	73.7	9.5
CY12	401.1	347.5	53.7
CY13	368.7	285.3	83.4
CY14	282.0	219.4	62.6
CY15	240.9	146.5	94.3
	1,375.9	**1,072.3**	**303.5**

Category	CY11	CY12	CY13	CY14	CY15	Total
RSP - Planned, Proposed, Ur	87.5%	80.5%	68.3%	45.2%	8.5%	57.8%
RSP - Concept	1.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Other PTF	0.0%	4.3%	4.9%	7.4%	8.3%	5.5%
Future RSP	0.0%	1.8%	4.2%	25.2%	44.1%	14.5%
Non-PTF	11.5%	13.4%	22.6%	22.2%	39.2%	22.1%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Total times respective year percentages	CY11	CY12	CY13	CY14	CY15	TOTAL
RSP - Planned, Proposed, Under Construction	72.8	323.0	251.6	127.5	20.4	795.4
RSP - Concept	0.9	-	-	-	-	0.9
Other PTF	-	17.4	18.1	20.9	19.9	76.3
Future RSP	-	7.1	15.5	71.0	106.2	199.8
TOTAL PTF	**73.7**	**347.5**	**285.3**	**219.4**	**146.5**	**1,072.3**
TOTAL NON-PTF	**9.5**	**53.7**	**83.4**	**62.6**	**94.3**	**303.5**
Totals	**83.2**	**401.1**	**368.7**	**282.0**	**240.9**	**1,375.9**
Variance to Above	-	-	-	-	-	-

Note: There is an additional $246m in NEEWS related projects scheduled to go into service in CY16

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of November 2011

22-Dec-11

Plant Section

	Attach. H Reference	November-11 2011
Transmission Plant:	I.A.1.a.	
NEP 's Total Inv. in Trans. Plant		$323,189,623 NEEWS In se
NEP' Investment in Wholesale Metering		$2,795,575
NEP' Total of other Inv. in Dist. Plant		$4,904,036
Less:Transmission Plant (Joint-Owned-Wyman)		$0
NEP's Investment in PTF Transmission Plant.		$1,161,721,161
NEP's Step-down Transformers beyond POD		101,587,978
Transmission Plant		$1,594,198,372
Transmission General Plant:	I.A.1.b.	
NEP's Investment in Gen'l Plant		$6,384,031
less:		
NEP's Generation Fac. as specifically identified in NEP's CTC		0
Transmission General Plant		$6,384,031
Transmission Plant Held for Future Use	I.A.1.c.	
Total investment on Plant held for future use		$7,948,313
Less: Generation Related site, Ayer & Groton		$6,920,542
Total Investment on Plant Held for Future Use		$1,027,771
Transmission Related CWIP	I.A.1.d.	9,311,081.2
Transmission Related Depreciation Reserve:	I.A.1.e.	
Trans. Depreciation Reserve		$345,678,323
Trans. Amort Reserve related to Joint-Owned (Wyman)		$0
Dist. Depreciation Reserve		$5,478,857
General Depreciation Reserve		$4,762,695
less:		
Generation-related depreciation reserve assoc. w/ assets identified in NEP's CTC		0
Total Transmission Depreciation Reserve		355,919,875

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of December 2010

29-Dec-11

Summary Page

	Attach. H Reference	December-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,491,378,833
Transmission General Plant	I.A.1.b.	6,828,851
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	26,131,513
Sub-Total Transmission Plant		$1,525,366,969
Trans. Depreciation Reserve	I.A.1.e.	-335,067,692
Trans. Accum. Deferred Taxes	I.A.1.f.	-321,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	697,351
Other Regulatory Assets	I.A.1.h.	25,761,506
AFUDC Regulatory Credit	I.A.1.i.	-1,312,582
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,416,127
Trans. Cash Working Capital	I.A.1.l.	9,086,340
Total Trans. Investment Base		$907,574,125

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,783,805
Trans. Depreciation & Amort. Expense	I.B.	2,819,426
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,951,723
Trans. Operation and Maint. Expense	I.G.	2,404,057
Trans. Admin. and General Expense	I.H.	3,653,502
Trans. Integrated Facilities Credit (Expense)	I.I.	4,282,124
Trans. Revenue Credit	I.J.	-19,146,076
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,124,240
Less: PTF Demand Charge Revenues	December-10	$887,176
Non-PTF Trans. Revenue Requirement		**$6,011,416.40**
PTF Transmission Revenue Requirement	December-10	**-$887,176.33**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of November 2011

22-Dec-11

Summary Page

	Attach. H Reference	November-11 2011
nsmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,594,198,372
Transmission General Plant	I.A.1.b.	6,384,031
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP*	I.A.1.d.	9,311,081
Sub-Total Transmission Plant		$1,610,921,256
Trans. Depreciation Reserve	I.A.1.e.	-355,919,875
Trans. Accum. Deferred Taxes	I.A.1.f.	-345,812,960
Trans. Loss on Reacquired Debt	I.A.1.g.	436,057
Other Regulatory Assets	I.A.1.h.	23,365,564
AFUDC Regulatory Credit	I.A.1.i.	-2,092,621
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	3,901,188
Trans. Cash Working Capital	I.A.1.l.	15,381,169
Total Trans. Investment Base		$950,179,777

Costs To Be Included In The Monthly Network Rate

nsmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,530,303
Trans. Depreciation & Amort. Expense	I.B.	2,979,250
Trans. Amort. of Loss on Reacq. Debt	I.C.	16,884
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	396,138
Trans. Municipal Tax Expense	I.F.	2,115,941
Trans. Operation and Maint. Expense	I.G.	7,464,123
Trans. Admin. and General Expense	I.H.	2,789,990
Trans. Integrated Facilities Credit (Expense)	I.I.	8,695,508
Trans. Revenue Credit	I.J.	-16,394,506
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$17,560,727
Less: PTF Demand Charge Revenues	November-11	-$9,109,026
Non-PTF Trans. Revenue Requirement		**$8,451,700.41**
PTF Transmission Revenue Requirement	November-11	**$9,109,026.40**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of October 2011

29-Feb-12

Summary Page

	Attach. H Reference	October-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,551,372,882
Transmission General Plant	I.A.1.b.	6,384,031
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	44,865,509
Sub-Total Transmission Plant		$1,603,650,193
Trans. Depreciation Reserve	I.A.1.e.	-353,655,801
Trans. Accum. Deferred Taxes	I.A.1.f.	-343,979,626
Trans. Loss on Reacquired Debt	I.A.1.g.	452,941
Other Regulatory Assets	I.A.1.h.	23,761,702
AFUDC Regulatory Credit	I.A.1.i.	-2,096,065
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	3,863,906
Trans. Cash Working Capital	I.A.1.l.	4,828,728
Total Trans. Investment Base		$936,825,978

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,375,286
Trans. Depreciation & Amort. Expense	I.B.	2,939,286
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	396,138
Trans. Municipal Tax Expense	I.F.	2,115,953
Trans. Operation and Maint. Expense	I.G.	183,556
Trans. Admin. and General Expense	I.H.	3,035,597
Trans. Integrated Facilities Credit (Expense)	I.I.	4,905,485
Trans. Revenue Credit	I.J.	-18,315,521
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-2,137,365
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$2,489,951
Less: PTF Demand Charge Revenues	October-11	$2,566,711
Non-PTF Trans. Revenue Requirement		**$5,056,662.14**
PTF Transmission Revenue Requirement	October-11	**-$2,566,711.35**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of September 2011

22-Nov-11

Summary Page

	Attach. H Reference	September-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,549,051,916
Transmission General Plant	I.A.1.b.	6,384,031
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	43,530,312
Sub-Total Transmission Plant		$1,599,994,031
Trans. Depreciation Reserve	I.A.1.e.	-352,139,488
Trans. Accum. Deferred Taxes	I.A.1.f.	-342,146,293
Trans. Loss on Reacquired Debt	I.A.1.g.	477,382
Other Regulatory Assets	I.A.1.h.	24,157,840
AFUDC Regulatory Credit	I.A.1.i.	2,096,217
Trans. Prepayments	I.A.1.j.	3,178,215
Trans. Materials & Supplies	I.A.1.k.	3,835,425
Trans. Cash Working Capital	I.A.1.l.	15,472,683
Total Trans. Investment Base		$954,926,012

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,528,570
Trans. Depreciation & Amort. Expense	I.B.	2,937,835
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	396,138
Trans. Municipal Tax Expense	I.F.	2,131,225
Trans. Operation and Maint. Expense	I.G.	8,213,470
Trans. Admin. and General Expense	I.H.	2,101,652
Trans. Integrated Facilities Credit (Expense)	I.I.	8,105,382
Trans. Revenue Credit	I.J.	-21,156,322
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	191,141
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$12,440,627
Less: PTF Demand Charge Revenues	September-11	-$3,887,686
Non-PTF Trans. Revenue Requirement		**$8,552,941.13**
PTF Transmission Revenue Requirement	September-11	**$3,887,686.21**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of August 2011

22-Nov-11

Summary Page

	Attach. H Reference	August-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,548,496,306
Transmission General Plant	I.A.1.b.	6,979,539
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	42,437,857
Sub-Total Transmission Plant		$1,598,941,473
Trans. Depreciation Reserve	I.A.1.e.	-350,556,550
Trans. Accum. Deferred Taxes	I.A.1.f.	-340,312,960
Trans. Loss on Reacquired Debt	I.A.1.g.	501,823
Other Regulatory Assets	I.A.1.h.	24,553,978
AFUDC Regulatory Credit	I.A.1.i.	-2,096,325
Trans. Prepayments	I.A.1.j.	1,696,313
Trans. Materials & Supplies	I.A.1.k.	3,910,788
Trans. Cash Working Capital	I.A.1.l.	10,292,747
Total Trans. Investment Base		$946,931,287

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,437,749
Trans. Depreciation & Amort. Expense	I.B.	2,924,716
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	396,138
Trans. Municipal Tax Expense	I.F.	1,905,119
Trans. Operation and Maint. Expense	I.G.	3,194,124
Trans. Admin. and General Expense	I.H.	3,667,707
Trans. Integrated Facilities Credit (Expense)	I.I.	6,120,160
Trans. Revenue Credit	I.J.	-24,214,138
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$3,423,111
Less: PTF Demand Charge Revenues	August-11	$3,560,033
Non-PTF Trans. Revenue Requirement		**$6,983,143.92**
PTF Transmission Revenue Requirement	August-11	**-$3,560,032.51**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of July 2011

22-Nov-11

Summary Page

	Attach. H Reference	July-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,533,995,383
Transmission General Plant	I.A.1.b.	6,979,539
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	40,596,892
Sub-Total Transmission Plant		$1,582,599,585
Trans. Depreciation Reserve	I.A.1.e.	-347,281,047
Trans. Accum. Deferred Taxes	I.A.1.f.	-338,479,626
Trans. Loss on Reacquired Debt	I.A.1.g.	526,264
Other Regulatory Assets	I.A.1.h.	24,950,117
AFUDC Regulatory Credit	I.A.1.i.	-2,096,433
Trans. Prepayments	I.A.1.j.	3,246,319
Trans. Materials & Supplies	I.A.1.k.	3,974,859
Trans. Cash Working Capital	I.A.1.l.	9,540,475
Total Trans. Investment Base		$936,980,512

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,314,367
Trans. Depreciation & Amort. Expense	I.B.	2,908,331
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	396,138
Trans. Municipal Tax Expense	I.F.	2,335,701
Trans. Operation and Maint. Expense	I.G.	3,061,688
Trans. Admin. and General Expense	I.H.	3,298,629
Trans. Integrated Facilities Credit (Expense)	I.I.	5,000,870
Trans. Revenue Credit	I.J.	-20,986,914
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,320,346
Less: PTF Demand Charge Revenues	July-11	$1,154,984
Non-PTF Trans. Revenue Requirement		**$6,475,330.15**
PTF Transmission Revenue Requirement	July-11	**-$1,154,984.12**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of June 2011

22-Nov-11

Summary Page

	Attach. H Reference	June-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,531,440,192
Transmission General Plant	I.A.1.b.	6,980,541
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	39,546,927
Sub-Total Transmission Plant		$1,578,995,432
Trans. Depreciation Reserve	I.A.1.e.	-345,134,277
Trans. Accum. Deferred Taxes	I.A.1.f.	-336,646,293
Trans. Loss on Reacquired Debt	I.A.1.g.	550,705
Other Regulatory Assets	I.A.1.h.	25,346,255
AFUDC Regulatory Credit	I.A.1.i.	-2,096,541
Trans. Prepayments	I.A.1.j.	510,615
Trans. Materials & Supplies	I.A.1.k.	3,928,692
Trans. Cash Working Capital	I.A.1.l.	14,331,345
Total Trans. Investment Base		$939,785,933

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,313,279
Trans. Depreciation & Amort. Expense	I.B.	2,903,680
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	401,748
Trans. Municipal Tax Expense	I.F.	2,083,036
Trans. Operation and Maint. Expense	I.G.	5,579,613
Trans. Admin. and General Expense	I.H.	3,974,617
Trans. Integrated Facilities Credit (Expense)	I.I.	6,406,582
Trans. Revenue Credit	I.J.	-20,423,910
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$10,230,181
Less: PTF Demand Charge Revenues	June-11	-$2,690,422
Non-PTF Trans. Revenue Requirement		**$7,539,759.49**
PTF Transmission Revenue Requirement	June-11	**$2,690,421.62**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of May 2011

22-Nov-11

Summary Page

	Attach. H Reference	May-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,529,391,328
Transmission General Plant	I.A.1.b.	6,891,476
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	36,953,008
Sub-Total Transmission Plant		$1,574,263,583
Trans. Depreciation Reserve	I.A.1.e.	-342,800,961
Trans. Accum. Deferred Taxes	I.A.1.f.	-334,812,960
Trans. Loss on Reacquired Debt	I.A.1.g.	575,146
Other Regulatory Assets	I.A.1.h.	25,748,003
AFUDC Regulatory Credit	I.A.1.i.	-2,096,649
Trans. Prepayments	I.A.1.j.	2,352,852
Trans. Materials & Supplies	I.A.1.k.	4,128,071
Trans. Cash Working Capital	I.A.1.l.	8,589,472
Total Trans. Investment Base		$935,946,557

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,185,536
Trans. Depreciation & Amort. Expense	I.B.	2,899,627
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	401,748
Trans. Municipal Tax Expense	I.F.	2,082,201
Trans. Operation and Maint. Expense	I.G.	2,723,696
Trans. Admin. and General Expense	I.H.	3,002,619
Trans. Integrated Facilities Credit (Expense)	I.I.	5,574,417
Trans. Revenue Credit	I.J.	-17,675,562
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-227,661
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$7,958,157
Less: PTF Demand Charge Revenues	May-11	-$1,783,997
Non-PTF Trans. Revenue Requirement		**$6,174,160.11**
PTF Transmission Revenue Requirement	May-11	**$1,783,996.67**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of April 2011

22-Nov-11

Summary Page

	Attach. H Reference	April-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,527,320,095
Transmission General Plant	I.A.1.b.	6,891,476
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	33,793,973
Sub-Total Transmission Plant		$1,569,033,315
Trans. Depreciation Reserve	I.A.1.e.	-342,724,068
Trans. Accum. Deferred Taxes	I.A.1.f.	-331,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	599,587
Other Regulatory Assets	I.A.1.h.	24,224,523
AFUDC Regulatory Credit	I.A.1.i.	-1,910,654
Trans. Prepayments	I.A.1.j.	3,605,106
Trans. Materials & Supplies	I.A.1.k.	4,193,233
Trans. Cash Working Capital	I.A.1.l.	7,839,406
Total Trans. Investment Base		$933,486,554

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,135,722
Trans. Depreciation & Amort. Expense	I.B.	2,884,662
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	2,092,801
Trans. Operation and Maint. Expense	I.G.	3,283,912
Trans. Admin. and General Expense	I.H.	1,942,359
Trans. Integrated Facilities Credit (Expense)	I.I.	5,096,949
Trans. Revenue Credit	I.J.	-19,505,033
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,307,153
Less: PTF Demand Charge Revenues	April-11	$622,593
Non-PTF Trans. Revenue Requirement		**$5,929,746.21**
PTF Transmission Revenue Requirement	April-11	**-$622,593.12**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of March 2011

22-Nov-11

Summary Page

	Attach. H Reference	March-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,513,856,441
Transmission General Plant	I.A.1.b.	6,833,724
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	31,207,405
Sub-Total Transmission Plant		$1,552,925,341
Trans. Depreciation Reserve	I.A.1.e.	-340,190,979
Trans. Accum. Deferred Taxes	I.A.1.f.	-328,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	624,028
Other Regulatory Assets	I.A.1.h.	24,608,769
AFUDC Regulatory Credit	I.A.1.i.	-1,737,445
Trans. Prepayments	I.A.1.j.	122,720
Trans. Materials & Supplies	I.A.1.k.	4,430,779
Trans. Cash Working Capital	I.A.1.l.	13,537,258
Total Trans. Investment Base		$925,446,576

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,041,613
Trans. Depreciation & Amort. Expense	I.B.	2,866,411
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	2,102,231
Trans. Operation and Maint. Expense	I.G.	4,092,470
Trans. Admin. and General Expense	I.H.	4,932,369
Trans. Integrated Facilities Credit (Expense)	I.I.	5,470,007
Trans. Revenue Credit	I.J.	-20,468,398
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	2,951
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$8,415,437
Less: PTF Demand Charge Revenues	March-11	-$1,273,374
Non-PTF Trans. Revenue Requirement		**$7,142,062.95**
PTF Transmission Revenue Requirement	March-11	**$1,273,373.55**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of February 2011

Summary Page

	Attach. H Reference	February-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,508,675,044
Transmission General Plant	I.A.1.b.	6,833,724
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	27,934,161
Sub-Total Transmission Plant		$1,544,470,699
Trans. Depreciation Reserve	I.A.1.e.	-338,685,362
Trans. Accum. Deferred Taxes	I.A.1.f.	-326,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	648,469
Other Regulatory Assets	I.A.1.h.	24,993,015
AFUDC Regulatory Credit	I.A.1.i.	-1,586,874
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,540,076
Trans. Cash Working Capital	I.A.1.l.	11,038,101
Total Trans. Investment Base		$919,044,231

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,943,066
Trans. Depreciation & Amort. Expense	I.B.	2,848,837
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-32,905
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	2,104,037
Trans. Operation and Maint. Expense	I.G.	4,415,565
Trans. Admin. and General Expense	I.H.	2,943,169
Trans. Integrated Facilities Credit (Expense)	I.I.	4,898,143
Trans. Revenue Credit	I.J.	-21,713,809
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-306,082
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$4,508,708
Less: PTF Demand Charge Revenues	February-11	$1,909,924
Non-PTF Trans. Revenue Requirement		**$6,418,631.52**
PTF Transmission Revenue Requirement	February-11	**-$1,909,923.82**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of January 2011

22-Nov-11

Summary Page

	Attach. H Reference	January-11 2011
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,495,645,561
Transmission General Plant	I.A.1.b.	6,828,851
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	27,290,969
Sub-Total Transmission Plant		$1,530,793,152
Trans. Depreciation Reserve	I.A.1.e.	-336,741,133
Trans. Accum. Deferred Taxes	I.A.1.f.	-323,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	672,910
Other Regulatory Assets	I.A.1.h.	25,377,260
AFUDC Regulatory Credit	I.A.1.i.	-1,447,405
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,483,961
Trans. Cash Working Capital	I.A.1.l.	8,608,445
Total Trans. Investment Base		$907,873,297

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,811,667
Trans. Depreciation & Amort. Expense	I.B.	2,832,209
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,001
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	3,969,301
Trans. Operation and Maint. Expense	I.G.	4,304,531
Trans. Admin. and General Expense	I.H.	1,434,432
Trans. Integrated Facilities Credit (Expense)	I.I.	4,727,982
Trans. Revenue Credit	I.J.	-21,155,835
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,299,973
Less: PTF Demand Charge Revenues	January-11	$1,185,449
Non-PTF Trans. Revenue Requirement		**$6,485,421.79**
PTF Transmission Revenue Requirement	January-11	**-$1,185,448.81**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of Janaury 2010

Summary Page

	Attach. H Reference	January-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,390,596,685
Transmission General Plant	I.A.1.b.	6,485,196
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	12,639,187
Sub-Total Transmission Plant		$1,410,748,839
Trans. Depreciation Reserve	I.A.1.e.	-317,386,412
Trans. Accum. Deferred Taxes	I.A.1.f.	-297,679,157
Trans. Loss on Reacquired Debt	I.A.1.g.	966,202
Other Regulatory Assets	I.A.1.h.	27,910,586
AFUDC Regulatory Credit	I.A.1.i.	-336,891
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	3,971,384
Trans. Cash Working Capital	I.A.1.l.	8,756,431
Total Trans. Investment Base		$836,950,982

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,207,002
Trans. Depreciation & Amort. Expense	I.B.	2,625,246
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,038
Trans. Amort. of FAS 109	I.E.	363,808
Trans. Municipal Tax Expense	I.F.	2,868,495
Trans. Operation and Maint. Expense	I.G.	3,643,766
Trans. Admin. and General Expense	I.H.	2,193,854
Trans. Integrated Facilities Credit	I.I.	4,050,848
Trans. Revenue Credit	I.J.	-14,032,461
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-6,315,017
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$3,596,944
Less: PTF Demand Charge Revenues	January-10	$2,220,623
Non-PTF Trans. Revenue Requirement		**$5,817,566.65**
PTF Transmission Revenue Requirement	January-10	**-$2,220,622.91**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of February 2010

Summary Page

Transmission Investment Base:	Attach. H Reference	February-10 2010
Transmission Plant	I.A.1.a.	$1,399,147,605
Transmission General Plant	I.A.1.b.	6,485,196
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	14,449,311
Sub-Total Transmission Plant		$1,421,109,884
Trans. Depreciation Reserve	I.A.1.e.	-319,027,288
Trans. Accum. Deferred Taxes	I.A.1.f.	-298,929,157
Trans. Loss on Reacquired Debt	I.A.1.g.	941,761
Other Regulatory Assets	I.A.1.h.	27,546,778
AFUDC Regulatory Credit	I.A.1.i.	-387,921
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,377,408
Trans. Cash Working Capital	I.A.1.l.	10,279,938
Total Trans. Investment Base		$845,911,403

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,306,145
Trans. Depreciation & Amort. Expense	I.B.	2,641,077
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	363,808
Trans. Municipal Tax Expense	I.F.	1,766,401
Trans. Operation and Maint. Expense	I.G.	3,951,404
Trans. Admin. and General Expense	I.H.	2,901,888
Trans. Integrated Facilities Credit (Expense)	I.I.	4,428,291
Trans. Revenue Credit	I.J.	-14,974,909
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$9,375,538
Less: PTF Demand Charge Revenues	February-10	-$2,109,350
Non-PTF Trans. Revenue Requirement		**$7,266,187.54**
PTF Transmission Revenue Requirement	February-10	**$2,109,350.41**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of March 2010

Summary Page

	Attach. H Reference	March-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,414,088,009
Transmission General Plant	I.A.1.b.	6,485,196
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	15,588,850
Sub-Total Transmission Plant		$1,437,189,827
Trans. Depreciation Reserve	I.A.1.e.	-320,027,074
Trans. Accum. Deferred Taxes	I.A.1.f.	-300,179,157
Trans. Loss on Reacquired Debt	I.A.1.g.	917,320
Other Regulatory Assets	I.A.1.h.	27,182,969
AFUDC Regulatory Credit	I.A.1.i.	-446,793
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,224,528
Trans. Cash Working Capital	I.A.1.l.	10,438,791
Total Trans. Investment Base		$859,300,410

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,446,923
Trans. Depreciation & Amort. Expense	I.B.	2,663,781
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	363,808
Trans. Municipal Tax Expense	I.F.	1,494,090
Trans. Operation and Maint. Expense	I.G.	3,467,939
Trans. Admin. and General Expense	I.H.	3,491,255
Trans. Integrated Facilities Credit (Expense)	I.I.	4,885,185
Trans. Revenue Credit	I.J.	-19,082,200
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,722,213
Less: PTF Demand Charge Revenues	March-10	$343,076
Non-PTF Trans. Revenue Requirement		**$6,065,289.00**
PTF Transmission Revenue Requirement	March-10	**-$343,075.70**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of April 2010

Summary Page

	Attach. H Reference	March-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,424,309,468
Transmission General Plant	I.A.1.b.	6,502,823
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	16,654,529
Sub-Total Transmission Plant		$1,448,494,590
Trans. Depreciation Reserve	I.A.1.e.	-320,829,417
Trans. Accum. Deferred Taxes	I.A.1.f.	-301,429,157
Trans. Loss on Reacquired Debt	I.A.1.g.	892,879
Other Regulatory Assets	I.A.1.h.	26,819,161
AFUDC Regulatory Credit	I.A.1.i.	-514,635
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,498,863
Trans. Cash Working Capital	I.A.1.l.	9,739,275
Total Trans. Investment Base		$867,671,559

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,537,888
Trans. Depreciation & Amort. Expense	I.B.	2,688,029
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	363,808
Trans. Municipal Tax Expense	I.F.	1,749,739
Trans. Operation and Maint. Expense	I.G.	3,768,535
Trans. Admin. and General Expense	I.H.	2,724,315
Trans. Integrated Facilities Credit (Expense)	I.I.	3,915,223
Trans. Revenue Credit	I.J.	-17,957,471
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$5,781,500
Less: PTF Demand Charge Revenues	March-10	-$38,102
Non-PTF Trans. Revenue Requirement		**$5,743,398.05**
PTF Transmission Revenue Requirement	March-10	**$38,101.52**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of May 2010

Summary Page

	Attach. H Reference	May-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,429,195,563
Transmission General Plant	I.A.1.b.	6,502,823
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	17,208,787
Sub-Total Transmission Plant		$1,453,934,944
Trans. Depreciation Reserve	I.A.1.e.	-323,126,405
Trans. Accum. Deferred Taxes	I.A.1.f.	-303,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	868,438
Other Regulatory Assets	I.A.1.h.	28,634,537
AFUDC Regulatory Credit	I.A.1.i.	-586,148
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,529,072
Trans. Cash Working Capital	I.A.1.l.	8,358,696
Total Trans. Investment Base		$868,739,240

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,566,493
Trans. Depreciation & Amort. Expense	I.B.	2,702,697
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,254
Trans. Municipal Tax Expense	I.F.	2,227,004
Trans. Operation and Maint. Expense	I.G.	3,085,327
Trans. Admin. and General Expense	I.H.	2,487,136
Trans. Integrated Facilities Credit (Expense)	I.I.	4,277,685
Trans. Revenue Credit	I.J.	-16,266,687
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-67,939
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$7,387,404
Less: PTF Demand Charge Revenues	May-10	-$2,715,912
Non-PTF Trans. Revenue Requirement		**$4,671,491.98**
PTF Transmission Revenue Requirement	May-10	**$2,715,911.73**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of June 2010

Summary Page

	Attach. H Reference	June-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,436,403,557
Transmission General Plant	I.A.1.b.	6,541,457
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	18,953,936
Sub-Total Transmission Plant		$1,462,926,722
Trans. Depreciation Reserve	I.A.1.e.	-324,638,812
Trans. Accum. Deferred Taxes	I.A.1.f.	-306,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	843,997
Other Regulatory Assets	I.A.1.h.	28,066,980
AFUDC Regulatory Credit	I.A.1.i.	-672,648
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,575,670
Trans. Cash Working Capital	I.A.1.l.	11,771,666
Total Trans. Investment Base		$876,499,680

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,673,695
Trans. Depreciation & Amort. Expense	I.B.	2,714,423
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,254
Trans. Municipal Tax Expense	I.F.	1,752,775
Trans. Operation and Maint. Expense	I.G.	4,619,672
Trans. Admin. and General Expense	I.H.	3,228,106
Trans. Integrated Facilities Credit (Expense)	I.I.	4,148,373
Trans. Revenue Credit	I.J.	-21,702,533
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$3,810,196
Less: PTF Demand Charge Revenues	June-10	$2,405,790
Non-PTF Trans. Revenue Requirement		**$6,215,985.90**
PTF Transmission Revenue Requirement	June-10	**-$2,405,789.67**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of July 2010

Summary Page

	Attach. H Reference	July-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,450,005,392
Transmission General Plant	I.A.1.b.	6,541,457
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	19,816,815
Sub-Total Transmission Plant		$1,477,391,436
Trans. Depreciation Reserve	I.A.1.e.	-325,924,426
Trans. Accum. Deferred Taxes	I.A.1.f.	-308,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	819,556
Other Regulatory Assets	I.A.1.h.	27,682,734
AFUDC Regulatory Credit	I.A.1.i.	-771,078
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,718,017
Trans. Cash Working Capital	I.A.1.l.	11,302,099
Total Trans. Investment Base		$886,344,444

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,790,321
Trans. Depreciation & Amort. Expense	I.B.	2,734,510
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,758,178
Trans. Operation and Maint. Expense	I.G.	4,338,315
Trans. Admin. and General Expense	I.H.	3,196,417
Trans. Integrated Facilities Credit (Expense)	I.I.	4,046,258
Trans. Revenue Credit	I.J.	-24,541,672
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	-1,804,111
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		-$1,106,105
Less: PTF Demand Charge Revenues	July-10	$6,767,340
Non-PTF Trans. Revenue Requirement		**$5,661,234.58**
PTF Transmission Revenue Requirement	July-10	**-$6,767,339.52**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of August 2010

Summary Page

	Attach. H Reference	August-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,454,674,280
Transmission General Plant	I.A.1.b.	6,541,457
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	20,542,827
Sub-Total Transmission Plant		$1,482,786,335
Trans. Depreciation Reserve	I.A.1.e.	-327,711,811
Trans. Accum. Deferred Taxes	I.A.1.f.	-311,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	795,115
Other Regulatory Assets	I.A.1.h.	27,298,488
AFUDC Regulatory Credit	I.A.1.i.	-868,123
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,946,051
Trans. Cash Working Capital	I.A.1.l.	11,112,882
Total Trans. Investment Base		$886,985,043

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,830,675
Trans. Depreciation & Amort. Expense	I.B.	2,752,380
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,770,932
Trans. Operation and Maint. Expense	I.G.	5,044,396
Trans. Admin. and General Expense	I.H.	2,364,192
Trans. Integrated Facilities Credit (Expense)	I.I.	4,412,530
Trans. Revenue Credit	I.J.	-27,087,300
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		-$1,536,517
Less: PTF Demand Charge Revenues	August-10	$7,682,842
Non-PTF Trans. Revenue Requirement		**$6,146,325.11**
PTF Transmission Revenue Requirement	August-10	**-$7,682,841.88**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of September 2010

Summary Page

	Attach. H Reference	September-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,469,148,307
Transmission General Plant	I.A.1.b.	6,729,526
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	22,387,056
Sub-Total Transmission Plant		$1,499,292,660
Trans. Depreciation Reserve	I.A.1.e.	-329,404,927
Trans. Accum. Deferred Taxes	I.A.1.f.	-313,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	770,674
Other Regulatory Assets	I.A.1.h.	26,914,243
AFUDC Regulatory Credit	I.A.1.i.	-959,365
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,782,556
Trans. Cash Working Capital	I.A.1.l.	11,046,560
Total Trans. Investment Base		$898,568,507

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,974,453
Trans. Depreciation & Amort. Expense	I.B.	2,771,220
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,759,037
Trans. Operation and Maint. Expense	I.G.	4,346,876
Trans. Admin. and General Expense	I.H.	3,017,498
Trans. Integrated Facilities Credit (Expense)	I.I.	4,312,454
Trans. Revenue Credit	I.J.	-25,448,864
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$108,352
Less: PTF Demand Charge Revenues	September-10	$6,227,101
Non-PTF Trans. Revenue Requirement		**$6,335,452.61**
PTF Transmission Revenue Requirement	September-10	**-$6,227,100.60**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of October 2010

Summary Page

	Attach. H Reference	October-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,472,916,529
Transmission General Plant	I.A.1.b.	6,729,526
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	25,850,176
Sub-Total Transmission Plant		$1,506,524,001
Trans. Depreciation Reserve	I.A.1.e.	-330,998,997
Trans. Accum. Deferred Taxes	I.A.1.f.	-316,373,894
Trans. Loss on Reacquired Debt	I.A.1.g.	746,233
Other Regulatory Assets	I.A.1.h.	26,529,997
AFUDC Regulatory Credit	I.A.1.i.	-1,065,478
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,590,330
Trans. Cash Working Capital	I.A.1.l.	11,627,248
Total Trans. Investment Base		$901,579,439

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,025,562
Trans. Depreciation & Amort. Expense	I.B.	2,789,024
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,765,732
Trans. Operation and Maint. Expense	I.G.	4,537,275
Trans. Admin. and General Expense	I.H.	3,214,223
Trans. Integrated Facilities Credit (Expense)	I.I.	4,326,966
Trans. Revenue Credit	I.J.	-25,772,302
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$262,159
Less: PTF Demand Charge Revenues	October-10	$6,226,958
Non-PTF Trans. Revenue Requirement		**$6,489,117.29**
PTF Transmission Revenue Requirement	October-10	**-$6,226,958.06**

New England Power Company
Network Transmission Revenue Requirement
ACTUAL for the month of November 2010

Summary Page

	Attach. H Reference	November-10 2010
Transmission Investment Base:		
Transmission Plant	I.A.1.a.	$1,482,572,827
Transmission General Plant	I.A.1.b.	6,782,529
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	27,923,385
Sub-Total Transmission Plant		$1,518,306,512
Trans. Depreciation Reserve	I.A.1.e.	-333,469,233
Trans. Accum. Deferred Taxes	I.A.1.f.	-318,873,894
Trans. Loss on Reacquired Debt	I.A.1.g.	721,792
Other Regulatory Assets	I.A.1.h.	26,145,752
AFUDC Regulatory Credit	I.A.1.i.	-1,184,462
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	4,568,929
Trans. Cash Working Capital	I.A.1.l.	8,300,402
Total Trans. Investment Base		$904,515,798

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$9,075,309
Trans. Depreciation & Amort. Expense	I.B.	2,801,738
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,008
Trans. Amort. of FAS 109	I.E.	384,246
Trans. Municipal Tax Expense	I.F.	1,766,850
Trans. Operation and Maint. Expense	I.G.	3,149,069
Trans. Admin. and General Expense	I.H.	2,384,532
Trans. Integrated Facilities Credit (Expense)	I.I.	4,381,094
Trans. Revenue Credit	I.J.	-19,910,027
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	0
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$4,024,245
Less: PTF Demand Charge Revenues	November-10	$1,754,441
Non-PTF Trans. Revenue Requirement		**$5,778,685.78**
PTF Transmission Revenue Requirement	November-10	**-$1,754,441.06**

REVISED FOR ADIT } ZERO DEBT RATE

New England Power Company
Network Transmission Revenue Requirement
Actual for the month of December 2009

03-Jan-11

Summary Page

Transmission Investment Base:	Attach. H Reference	December-09 2009
Transmission Plant	I.A.1.a.	$1,382,812,087
Transmission General Plant	I.A.1.b.	6,485,196
Trans. Plant Held for Future Use	I.A.1.c.	1,027,771
Trans Related CWIP	I.A.1.d.	10,485,509
Sub-Total Transmission Plant		$1,400,810,563
Trans. Depreciation Reserve	I.A.1.e.	-313,223,363
Trans. Accum. Deferred Taxes	I.A.1.f.	-296,429,157
Trans. Loss on Reacquired Debt	I.A.1.g.	990,643
Other Regulatory Assets	I.A.1.h.	28,274,395
AFUDC Regulatory Credit	I.A.1.i.	-296,915
Trans. Prepayments	I.A.1.j.	0
Trans. Materials & Supplies	I.A.1.k.	3,835,249
Trans. Cash Working Capital	I.A.1.l.	9,870,763
Total Trans. Investment Base		$833,832,179

Costs To Be Included In The Monthly Network Rate

Transmission Revenue Requirement:		
Return and Assoc. Income Taxes	I.A.	$8,159,743
Trans. Depreciation & Amort. Expense	I.B.	2,583,296
Trans. Amort. of Loss on Reacq. Debt	I.C.	24,441
Trans. Amort. of Investment Tax Credits	I.D.	-33,841
Trans. Amort. of FAS 109	I.E.	363,808
Trans. Municipal Tax Expense	I.F.	1,562,968
Trans. Operation and Maint. Expense	I.G.	3,648,687
Trans. Admin. and General Expense	I.H.	2,931,822
Trans. Integrated Facilities Credit	I.I.	4,261,301
Trans. Revenue Credit	I.J.	-18,016,630
Distribution Integrated Facilities Credit	I.K.	0
Billing Adjustments	I.L.	6,315,017
Reactive Power Expense	I.M.	0
Bad Debt Expense	I.N.	0
Total Trans. Revenue Requirement		$11,800,613
Less: PTF Demand Charge Revenues	December-09	-$4,311,186
Non-PTF Trans. Revenue Requirement		**$7,489,426.51**
PTF Transmission Revenue Requirement	December-09	**$4,311,186.05**

Division 1-4

Request:

Please provide a copy of the ISO-NE power point document referred to by Mr. Loschiavo and a spreadsheet calculating the 16.6% carrying charge. Please also provide a spreadsheet with actual and forecasted kWhs.

Response:

Please see attached copy of the ISO-NE Powerpoint document referred to by Mr. Loschiavo as Attachment 1, DIV 1-4.

For actual and forecasted kWhs, please see Attachment 2, DIV 1-4 and Attachment 3, DIV 1-4.

Prepared by or under the supervision of: James L. Loschiavo

RNS Rates – Five Year Forecast

PTO AC - Rates Working Group - Presentation

NEPOOL Reliability Committee / Transmission Committee – Summer Meeting

July 26-27, 2011

Presentation Overview

- 2011 Forecast Comparison - Summary
- 2011 Forecast Comparison - Detail
- 2012 – 2015 Forecast - Disclaimer
- 2012 – 2015 Forecast - Summary
- New England RNS Rate Forecast - Summary
- Appendix – RNS Rate Forecast Components
    - 2012 Forecast Components
    - 2013 Forecast Components
    - 2014 Forecast Components
    - 2015 Forecast Components

2011 Forecast Comparison - Summary

PTO AC initially estimated $766M of PTF Additions <u>in service</u> and Construction Work In Progress ("CWIP") for MPRP in 2011

- This level of projected PTF Additions and CWIP resulted in:
  - Forecasted RNS revenue requirement of $127M with an estimated RNS Rate Impact of $6.53/kW-Yr.
    - Based on <u>actual 2009</u> Carrying Charge Factors & 12CP RNS Load (19,458 MW)

RNS Rate effective June 1, 2011 includes an estimated $1,304M of PTF Additions <u>in service</u> and CWIP for MPRP and NEEWS in 2011

- This level of projected PTF Additions and CWIP results in:
  - Forecasted RNS revenue requirement of $206M with an estimated RNS Rate Impact of $9.76/kW-Yr.
    - Based on <u>actual 2010</u> Carrying Charge Factors & 12CP RNS Load (21,086 MW)

Changes

- CAPITAL ADDITIONS IN-SERVICE AND CWIP
- CARRYING CHARGE FACTORS
- 12-CP RNS LOADS

2011 Forecast Comparison - Detail

	2010 RC/TC Summer Meeting Estimate		June 1, 2011 RNS Rate		
Participating Transmission Owner	2011 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	2011 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	Variance Impact ($/kW-Yr)
BHE	37	7	39	7	(0.02)
CMP	294	48	491	83	1.43
CTMEEC	-	-	48	7	0.35
Highgate	-	-	-	-	-
HG&E	-	-	-	-	-
NHT	1	-	3	1	0.02
NGRID	213	35	127	19	(0.91)
NSTAR	63	8	49	7	(0.12)
NU	112	20	535	81	2.84
UI*	17	4	(9)	(2)	(0.27)
VT Transco	29	5	21	3	(0.09)
Total	766	127	1,304	206	-
RNS Rate Incremental Impact ($/kW-Yr)	$6.53		$9.76		$3.23

Note: Figures may be off slightly due to rounding.

*Includes ISO-NE's final determination of the transmission cost allocation (TCA) application for the Middletown – Norwalk (M-N) project.

2012 - 2015 Forecast - Disclaimer

The 2012-2015 forecast herein provides an indicative RNS rate trend; it should be used for illustrative purposes only.

The estimated data utilized by the PTO AC to develop this forecast of RNS rates is based upon estimated capital additions provided to the Committee by all the New England Transmission Owners. Estimates for 2012 capital additions will be finalized during the normal course of update to the RNS rate effective June 1, 2012 and will reflect more current information.

The PTO AC acknowledges that this 2012-2015 forecast is based on a number of assumptions and variables including, among others, estimated project need, design, scope, labor & materials costs, inflation, site & permitting approvals, transmission in-service dates, estimated carrying charges & coincident peak network loads. It is therefore expected that such estimates and assumptions will change over time as more current data become available.

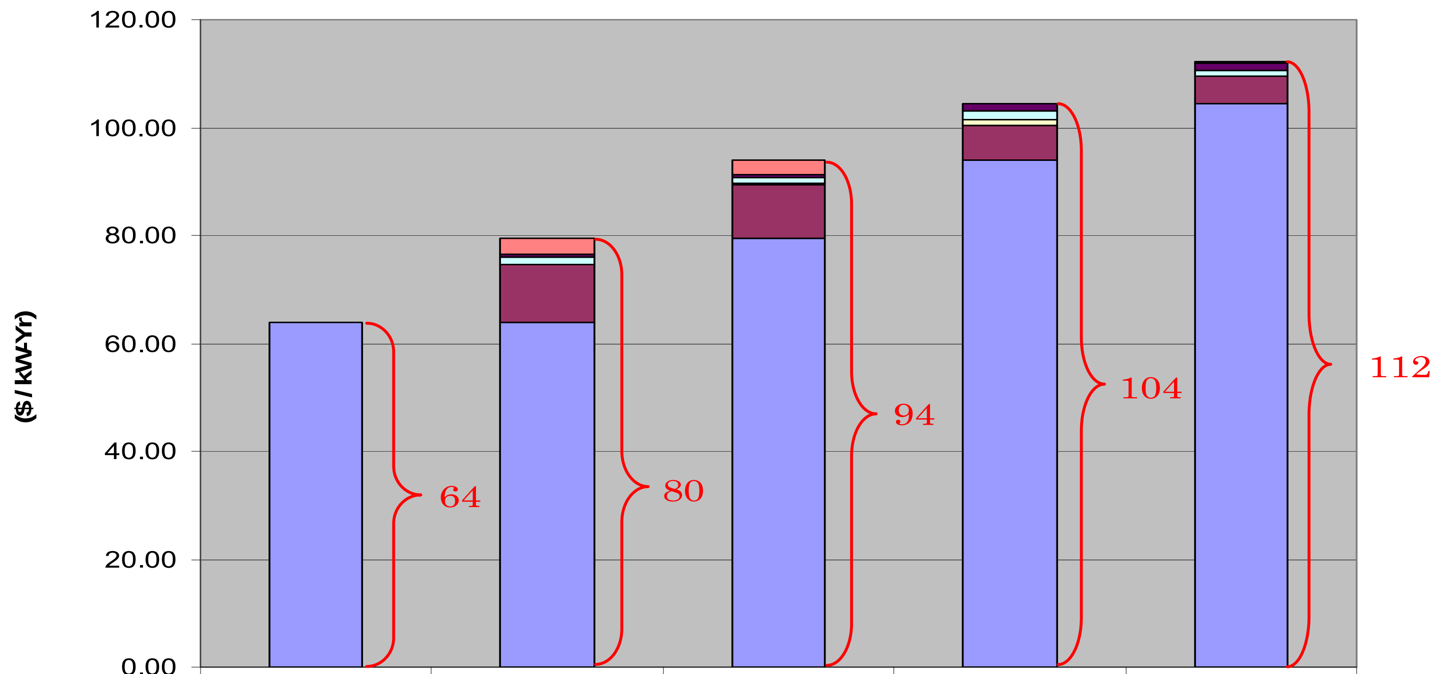
In addition, the 2012-2015 forecast reflects gross costs and does not include assumptions pertaining to savings (e.g., associated with congestion, unlocked capacity, etc.) or prior year true-up adjustments.

2012 - 2015 Forecast - Summary

	2012	2013	2014	2015
Estimated Additions In-Service and CWIP ($M)	1,994	1,810	1,336	944
Forecasted Revenue Requirement ($M)	332	304	219	162
Estimated RNS Rate Impact ($/kW-Yr)	16	14	10	8
Estimated RNS Rate Forecast ($/kW-Yr)	80	94	104	112
Estimated RNS Rate Forecast ($/kWh) *Assumes a 60% Load Factor*	0.015	0.018	0.020	0.021

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

New England RNS Rate Forecast – Summary



	2011	2012	2013	2014	2015
CWIP		3.19	2.68	0.10	0.33
Future RSP		0.31	0.51	1.17	1.30
Other PTF		1.44	1.08	1.69	0.92
RSP-Concept		0.16	0.24	1.16	0.12
RSP-Proposed, Planned, UC		10.62	9.92	6.27	5.06
Prior Year Rate	63.88	63.88	79.60	94.03	104.42
Total Rate Effective June 1	63.88	79.60	94.03	104.42	112.15
$ / kWh *	.012	.015	.018	.020	.021

* Assumes a 60% load factor

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

Appendix

RNS Rate Forecast Components

2012 Forecast Components

Participating Transmission Owner	2012 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	RNS Rate Impact ($/kW-Yr)	Key Drivers - Major Projects >$50M
BHE	**64**	**11**	**0.51**	Down East Reliability Improvement, SVC Filter Upgrade
CMP	**798**	**134**	**6.35**	Maine Power Reliability Program (MPRP) – CWIP & In-Service
HIGHGATE	**36**	**6**	**0.30**	
HG&E	**4**	**1**	**0.04**	
NHT	**8**	**2**	**0.08**	
NGRID	**348**	**55**	**2.61**	New England East-West Solution (NEEWS)
NSTAR	**204**	**28**	**1.33**	Lower SEMA Carver to Bourne 345kV Line
NU	**383**	**67**	**3.19**	New England East-West Solution (NEEWS)
UI	**85**	**17**	**0.81**	Grand Avenue 115kV Switching Station Rebuild
VT Transco	**64**	**11**	**0.50**	
Total	**1,994**	**332**	**15.72**	

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

2013 Forecast Components

Participating Transmission Owner	2013 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	RNS Rate Impact ($/kW-Yr)	Key Drivers - Major Projects >$50M
BHE	2	-	.01	
CMP	715	120	5.69	Maine Power Reliability Program (MPRP) – CWIP & In-Service
HIGHGATE	-	-	-	
HG&E	-	-	-	
NHT	7	2	0.07	
NGRID	285	45	2.14	New England East-West Solution (NEEWS)
NSTAR	87	12	0.56	
NU	685	120	5.70	New England East-West Solution (NEEWS)
UI	15	3	0.15	
VT Transco	14	2	0.11	
Total	1,810	304	14.43	

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

2014 Forecast Components

Participating Transmission Owner	2014 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	RNS Rate Impact ($/kW-Yr)	Key Drivers - Major Projects >$50M
BHE	-	-	-	
CMP	604	101	4.79	Maine Power Reliability Program (MPRP) – CWIP & In-Service
HIGHGATE	-	-	-	
HG&E	-	-	-	
NHT	10	2	0.09	
NGRID	219	35	1.65	New England East-West Solution (NEEWS)
NSTAR	183	25	1.19	
NU	306	54	2.54	Stamford Area Reliability
UI	11	2	0.11	
VT Transco	3	-	0.02	
Total	1,336	219	10.39	

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

2015 Forecast Components

Participating Transmission Owner	2015 Projected PTF Additions (including CWIP) ($ in Millions)	Forecasted RNS Revenue Requirements ($ in Millions)	RNS Rate Impact ($/kW-Yr)	Key Drivers - Major Projects >$50M
BHE	-	-	-	
CMP	69	12	0.55	Maine Power Reliability Program (MPRP) – CWIP & In-Service
HIGHGATE	-	-	-	
HG&E	-	-	-	
NHT	21	4	0.20	
NGRID	147	23	1.10	New England East-West Solution (NEEWS)
NSTAR	69	9	0.45	
NU	530	93	4.41	New England East-West Solution (NEEWS), Berkshire Area Solution
UI	105	21	1.00	Pequonnock 115kV Fault Duty Mitigation
VT Transco	3	-	0.02	
Total	944	162	7.73	

Forecast is preliminary and for illustrative purposes only. Estimates do not reflect revised ISO forecasts or RSP project listing updates after April 2011. Figures may be off slightly due to rounding.

New England Power Company
PTF Rate Calculation
Estimated For the Year 2012

Ln #			
	Development of Estimated PTF Rate:		
1	Total Regional Network Service Rate through May 31, 2012	$63.87	/KW-YR
	ESTIMATED Increase in ISO Rate Effective June 1, 2012		
2	Total ESTIMATED PTO Plant Additions	$ 1,994,000,000	
3	x Estimated Carrying Charge	16.63%	
4	/ 2010 ISO Network Load	21,086,421	
5	Additional Estimated ISO Regional Network Service Rate	$15.73	/KW-YR
6	Regional Network Service Rate in effect June 1, 2012 through May 31, 2013	$79.60	/KW-YR

Line 1 = PTO Informational Filing dated 7/29/11
Line 2 = PTO Forecast RWG Presentation 7/26/11
Line 3 = PTO Forecast RWG Presentation 7/26/11
Line 4 = PTO Informational Filing dated 7/29/11
Line 5 = Line 2 * Line 3 / Line 4
Line 6 = Line 1 + Line 5

Line 5: Additional RNS Rate	$15.73
Line 2: Estimated Plant Adds	$ 1,994,000,000
Line 4: 2010 ISO Avg 12CP Load	21,086,421
Line 3 =(Line 5 / Line 2) * Line 4	16.63%

The Narragansett Electric Company
Actual and Forecasted kWhs

Actual kWhs by Rate Class - 2009

	A-16/A-60	C-06/C-08	G-02	B-32/G-32	B-62/G-62	S-10/S-14	X-01	Total
Jan-09	313,415,480	61,664,609	117,391,044	199,908,770	54,410,169	7,488,303	2,479,535	756,757,910
Feb-09	254,835,294	48,091,778	111,093,765	173,264,518	42,950,540	6,792,589	2,047,602	639,076,086
Mar-09	243,988,244	46,397,788	149,030,731	161,523,891	40,421,706	5,855,030	2,105,117	649,322,507
Apr-09	229,158,071	44,974,552	103,715,254	168,683,420	(5,473,356)	5,176,057	2,295,498	548,529,496
May-09	197,629,459	40,066,435	99,533,327	153,972,755	93,087,823	4,248,112	2,201,782	590,739,693
Jun-09	201,735,968	40,679,442	102,296,355	161,804,456	46,941,429	4,603,514	1,963,967	560,025,131
Jul-09	240,802,494	47,437,177	135,895,602	168,523,626	44,649,305	4,185,541	2,291,175	643,784,920
Aug-09	289,370,680	49,582,100	119,436,066	175,129,138	45,512,087	2,159,692	2,211,942	683,401,705
Sep-09	301,367,244	51,425,682	124,315,021	183,143,065	51,018,153	7,788,264	2,149,503	721,206,932
Oct-09	210,804,475	42,087,780	109,130,496	171,745,970	47,850,446	5,910,394	2,242,469	589,772,030
Nov-09	210,658,865	39,627,603	96,549,014	154,842,154	48,323,082	6,350,261	2,115,156	558,466,135
Dec-09	244,114,073	43,564,509	105,424,367	171,638,075	45,675,617	7,387,533	2,379,594	620,183,768
Total	2,937,880,347	555,599,455	1,373,811,042	2,044,179,838	555,367,001	67,945,290	26,483,340	7,561,266,313

Actual kWhs by Rate Class - 2010

	A-16/A-60	C-06/C-08	G-02	B-32/G-32	B-62/G-62	S-10/S-14	X-01	Total
Jan-10	306,500,115	42,960,596	115,361,957	181,172,251	47,955,758	7,873,912	2,000,995	703,825,584
Feb-10	261,394,869	48,279,244	105,534,967	166,115,038	44,566,153	6,255,356	1,977,498	634,123,125
Mar-10	244,864,987	46,986,949	107,698,026	168,585,819	40,772,104	5,793,480	1,873,261	616,574,626
Apr-10	219,491,797	42,685,106	103,948,874	165,801,776	44,636,017	5,464,820	1,935,700	583,964,090
May-10	204,322,772	40,061,169	95,614,503	156,949,558	45,175,733	4,167,971	1,746,114	548,037,820
Jun-10	222,274,830	43,049,911	108,993,609	168,582,019	47,609,237	3,242,744	1,809,892	595,562,242
Jul-10	352,748,399	56,540,312	133,464,173	196,635,560	49,345,951	4,451,209	2,094,991	795,280,595
Aug-10	337,614,092	56,450,529	132,054,049	194,187,488	52,169,874	4,587,947	1,953,239	779,017,218
Sep-10	291,160,247	52,471,301	125,930,877	188,653,637	54,867,672	5,082,775	2,059,624	720,226,133
Oct-10	221,761,588	43,275,655	106,180,514	169,578,759	46,591,584	5,378,742	1,862,511	594,629,353
Nov-10	214,825,924	39,494,251	98,925,624	158,647,289	45,625,777	6,893,929	1,883,298	566,296,092
Dec-10	248,680,711	43,895,736	102,741,611	164,065,463	44,032,661	6,778,361	2,114,993	612,309,536
Total	3,125,640,331	556,150,759	1,336,448,784	2,078,974,657	563,348,521	65,971,246	23,312,116	7,749,846,414

Actual kWhs by Rate Class - 2011

	A-16/A-60	C-06/C-08	G-02	B-32/G-32	B-62/G-62	S-10/S-14	X-01	Total
Jan-11	300,816,490	51,362,834	113,957,707	165,824,103	42,397,861	7,436,190	1,856,614	683,651,799
Feb-11	270,708,288	48,787,838	106,873,224	171,334,314	46,646,837	6,102,447	1,782,050	652,234,998
Mar-11	244,377,656	47,081,664	105,981,446	169,981,057	44,719,536	5,432,393	1,961,771	619,535,523
Apr-11	231,248,656	44,850,371	102,451,649	158,074,607	36,345,458	5,556,731	1,982,599	580,510,071
May-11	203,607,359	40,605,322	99,824,603	163,024,697	51,500,583	4,064,070	1,955,628	564,582,262
Jun-11	227,044,026	44,222,943	108,127,926	176,340,467	43,165,632	4,147,407	1,801,309	604,849,710
Jul-11	313,118,284	53,654,412	125,995,048	181,370,523	44,739,199	4,289,372	2,098,224	725,265,062
Aug-11	342,832,395	56,939,844	131,869,042	195,566,853	55,807,821	4,458,235	1,891,044	789,365,234
Sep-11	289,505,685	51,013,239	121,574,801	177,241,910	49,891,141	4,945,013	1,907,401	696,079,190
Oct-11	229,571,144	44,502,980	109,555,439	173,848,634	44,202,929	5,566,296	1,826,372	609,073,794
Nov-11	224,732,857	42,943,684	101,961,445	165,876,720	41,687,506	6,775,423	1,954,901	585,932,536
Dec-11	236,749,225	42,742,842	100,344,220	166,384,617	40,552,222	6,709,247	1,830,500	595,312,873
	3,114,312,065	568,707,973	1,328,516,550	2,064,868,502	541,656,725	65,482,824	22,848,413	7,706,393,052

Forecasted kWhs by Rate Class - April 1, 2012 through March 31, 2013

	A-16/A-60	C-06/C-08	G-02	B-32/G-32	B-62/G-62	S-10/S-14	X-01	Total
Apr-12	233,678,233	45,561,035	102,350,063	157,881,768	39,806,926	5,671,704	1,982,599	586,932,328
May-12	214,976,263	43,459,670	98,375,232	175,851,204	54,608,257	4,542,959	1,955,628	593,769,213
Jun-12	218,786,379	44,203,893	108,638,319	172,773,376	44,774,016	4,676,521	1,801,309	595,653,813
Jul-12	320,015,945	55,398,316	124,282,947	190,502,081	46,570,517	4,454,365	2,098,224	743,322,396
Aug-12	318,027,090	56,571,040	131,548,498	196,114,500	51,780,616	5,082,826	1,953,239	761,077,809
Sep-12	287,870,404	53,656,463	124,586,485	198,950,313	51,680,078	6,071,360	2,059,624	724,874,727
Oct-12	224,915,321	44,771,863	105,774,820	174,943,909	48,609,540	6,575,476	1,862,511	607,453,440
Nov-12	223,914,183	42,182,315	97,889,114	170,187,814	47,965,537	6,992,934	1,883,298	591,015,194
Dec-12	245,336,294	46,261,033	101,872,128	170,806,885	50,078,813	7,631,232	2,114,993	624,101,379
Jan-13	312,025,932	55,485,254	110,499,130	188,128,551	45,234,928	7,422,324	1,856,614	720,652,733
Feb-13	258,711,511	51,436,707	104,966,363	180,993,467	52,999,123	6,614,112	1,782,050	657,503,333
Mar-13	247,524,839	49,815,221	103,988,069	180,332,162	48,719,469	6,027,989	1,961,771	638,369,520
Total	3,105,782,394	588,802,811	1,314,771,168	2,157,466,029	582,827,820	71,763,802	23,311,860	7,844,725,884

Division 1-5

Request:

For all of the revenues, expenses, and credits contained in the Company's filings, does the Company reconcile or tie these values back to the Company's Books and accounts? If so, please explain this process and indicate which values are reconciled. If not, please explain why not.

Response:

The Company has an established process for review of each of the deferral accounts included in the Company's retail reconciliation filing. The Accounting department is responsible for the recording of revenue and expense to the General Ledger deferral accounts. The Regulatory department has an independent process of accumulating revenue and expenses on a monthly basis in its reconciliation models. On a quarterly basis, the two groups compare account balances and reconcile any differences. On an annual basis, a more comprehensive review is conducted prior to the annual filing with the Commission.

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