nationalgrid

Thomas R. Teehan
Senior Counsel

December 22, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4011 – National Grid Retail Rates 2009
<u>Responses to Record Requests</u>

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to Record Requests issued at the Commission's evidentiary hearing on December 19, 2008, in the above-captioned proceeding.

Please be advised that the Company is seeking protective treatment of the confidential attachment provided to Record Request 3 as permitted by Commission Rule 1.2(g) and by R.I.G.L. § 38-2-2(4)(i)(B). In compliance with Rule 1.2(g), National Grid is providing one complete unredacted copy of the confidential attachment in a sealed envelope marked **"Contains Privileged and Confidential Materials – Do Not Release."** Copies of the confidential, unredacted documents have also been provided to Paul Roberti and Steve Scialabba, representing the Division of Public Utilities and Carriers.

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

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4011 Service List

[1] Submitted on behalf of The Narragansett Electric Company d/b/a National Grid ("Company").

280 Melrose Street, Providence, RI 02907
T: 401-784-7667 ■ F: 401-784-4321 ■ thomas.teehan@us.ngrid.com ■ www.nationalgrid.com

Certificate of Service

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

Joanne M. Scanlon

December 22, 2008
Date

National Grid – Annual Reconciliation Retail Tariff Filing
Docket No. 4011
Service List Updated 11/25/08

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	401-784-7667 401-784-4321
Paul Roberti, Esq. Dept. of Attorney General 150 South Main St. Providence, RI 02903	Proberti@riag.ri.gov Steve.scialabba@ripuc.state.ri.us Mtobin@riag.ri.gov David.stearns@ripuc.state.ri.us	401-222-2424 401-222-3016
File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick RI 02889	Lmassaro@puc.state.ri.us Cwilson@puc.state.ri.us Nucci@puc.state.ri.us Anault@puc.state.ri.us	401-780-2017 401-941-1691

Record Request 1

Request:

Please indicate whether certification of qualification for low income credit is submitted by CAP agencies or by low income customers?

Response:

Certification is submitted by either CAP agencies or by the Rhode Island Department of Human Services.

Prepared by or under the supervision of: Jeanne A. Lloyd

Record Request 2

Request:

Provide a copy of the April 23, 2002 NEPOOL/ISO RNS Audit Report as filed in Docket No. OA97-237.

Response:

Please see attached copy of the April 23, 2002 RNS Audit Report as filed at FERC. The attached copy is being provided in CD- ROM format since it is 414 pages long.

Prepared by or under the supervision of: P. A. Viapiano

ORIGINAL

POOR QUALITY ORIGINAL

NEPOOL

ISO New England

April 23, 2002

02 APR 24 PM 12: 15
FEDERAL ENERGY REGULATORY COMMISSION

FILED OFFICE OF THE SECRETARY

VIA OVERNIGHT DELIVERY

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Docket No. OA97-237-012
Supplemental Compliance Filing – 1996, 1997 and 1998 NEPOOL RNS Audit Report

Dear Secretary Salas:

The New England Power Pool ("NEPOOL") Participants Committee ("NPC") and ISO New England Inc. ("ISO-NE")[1] hereby jointly file for information an original and fifteen (15) copies of this transmittal letter and referenced materials which are submitted in accordance with the requirements of a settlement agreement (the "Settlement Agreement") approved by the Commission by order dated July 30, 1999, *New England Power Pool*, 88 FERC ¶ 61,140 (the "July 30 Order"). That Settlement Agreement resolved issues regarding the justness and reasonableness of Attachment F and the Ancillary Service Schedules to the NEPOOL Open Access Transmission Tariff (the "NEPOOL Tariff"), which had been set for hearing by order dated April 20, 1998, *New England Power Pool*, 83 FERC ¶ 61,045 (the "April 20 Order").[2]

Among other things, the Settlement Agreement provided: (1) for completion of an audit of the charges for regional network service ("RNS") under the formula rate provisions of the NEPOOL Tariff for charges in effect for the NEPOOL rate years June 1, 1997 through May 31, 2000, which are based respectively on data from calendar years 1996, 1997 and 1998 (the "RNS

[1] Capitalized terms used but not defined in this letter and referenced materials are intended to have the same meanings given to such terms in Sections 1 and 6 of the Restated NEPOOL Agreement or Section I of the Restated NEPOOL Open Access Transmission Tariff.

[2] The Settlement Agreement was dated April 5, 1999 and formally titled "Comprehensive Agreement Resolving All Issues Raised in this Proceeding Except for One Issue Raised by Great Bay Power Company."

DSK 105EC 020430-0094-1

DOCKETED

Audit"); and (2) for the submission of the results of that audit (the "RNS Audit Report") to the Commission as an informational filing. The RNS Audit Report is submitted as Attachment 1 hereto. This filing is the informational filing required by the Settlement Agreement.

As discussed below, there are known disagreements with the RNS Audit Report that must be resolved before a final rebilling to comply with the Settlement Agreement can be accomplished. Accordingly, NEPOOL and ISO-NE join in requesting that the Commission (1) notice this filing and open a proceeding as necessary to review the RNS Audit Report, (2) assign a settlement judge to assist affected parties in resolving any disputes regarding the RNS Audit Report that may not be resolved by any Commission order pertaining to this filing, and (3) issue an order following any settlement proceedings with respect to acceptance of this supplemental notice of compliance. These actions will permit the final recalculation and rebilling of charges under the NEPOOL Tariff for this period as provided by the Settlement Agreement.

I. BACKGROUND

A. The Tariff Docket and Settlement Agreement

On December 31, 1996, the NEPOOL Executive Committee ("NEC") (the predecessor to the NPC) filed a comprehensive restructuring proposal which included the Restated NEPOOL Agreement and the NEPOOL Tariff. The Commission's April 20 Order conditionally accepted the NEPOOL Tariff, but directed that a public hearing be held with respect to, among other things, the justness and reasonableness of the formulas in Attachment F and of Ancillary Service Schedule 1 to the proposed Tariff. That hearing was conducted before Presiding Administrative Law Judge Lawrence Brenner in 1999 in Docket Nos. OA-97-237-007, ER97-1079-006, ER97-3574-005, OA97-608-005, ER97-4421-005 and ER98-499-004 (collectively, the "Tariff Docket").

To resolve the Tariff Docket, with the help of a settlement judge, all but one of the parties, Great Bay Power Company, executed a settlement that resolved all disputes being litigated except for the one issue raised by Great Bay.[3] A copy of the Settlement Agreement is included as Appendix B to the RNS Audit Report filed herewith. The Settlement Agreement included a stipulation between NEPOOL and Commission Trial Staff (the "NEPOOL-Staff Stipulation" or "Stipulation"), which resolved various issues raised by Staff in the Tariff Docket.

The Commission approved the Settlement Agreement in the July 30 Order. That Order also terminated the proceedings which comprised the Tariff Docket and provided for the opening of a subdocket of Docket OA97-237 for NEPOOL's September 27, 1999 compliance filing as to implementation of various aspects of the Settlement Agreement. NEPOOL's compliance filing

---

[3] By orders dated May 19, 1999, *New England Power Pool*, 87 FERC ¶63,004, Judge Brenner severed Great Bay from the settlement and certified the Settlement Agreement to the Commission. On September 1, 1999, Judge Brenner issued an Initial Decision, *New England Power Pool*, 88 FERC ¶ 63,006, denying Great Bay the relief it was seeking. Great Bay sought Commission review of that Initial Decision, but subsequently withdrew that request.

was reflected in the Forty-Fifth Agreement Amending the Restated NEPOOL Agreement (the "45th Agreement"), which was subsequently accepted by order dated December 20, 1999 in Docket No. ER99-4531-000, *New England Power Pool*, 89 FERC ¶ 61,292. In the Fall of 1999, each NEPOOL Transmission Owner submitted to ISO-NE a revised RNS revenue requirement for these rate years to effect compliance with the Settlement Agreement. The rates were then recalculated and rebilled accordingly.

B. The Scope of the RNS Audit

Section 6 of the Stipulation, incorporated into the Settlement Agreement, provides, in pertinent part, as follows:

> [ISO-NE] shall independently audit the charges in effect for the period June 1997 through May 2000, or direct that an audit[s] be conducted under its supervision by an independent third party. Such audit[s] shall verify, through such sampling as appropriate, that Transmission Providers are correctly accounting for PTF investment in accordance with the applicable NEPOOL rules for determining PTF investment. The results of any such audit[s] shall be filed with the Commission as an informational filing, and the charges recalculated to correct any errors identified in such audit, with refunds and surcharges, as appropriate, for any amounts previously over- or under-charged due to such errors.

Subject to certain Commission-approved transitional arrangements for the RNS rate, which are detailed in Schedule 9 of the NEPOOL Tariff, the charges for RNS in New England are based upon the total revenue requirement for Pool Transmission Facilities ("PTF") owned and operated by the New England Transmission Owners. The term "PTF" is defined generally to include those transmission facilities rated at 69 kV and above which allow for power to move freely on and across the New England transmission network.

NEPOOL developed a set of rules for determining investment to be included in PTF, encaptioned "Rules for Determining Investment to be Included in PTF." Those rules have evolved over time and the results of the RNS Audit Report are intended to reflect that evolution. The PTF rules in effect for the rate year ending May 31, 1998 are referred to in the RNS Audit Report as the "Prior PTF Rules."[4] The PTF Rules in effect for audited rate years since June 1, 1998 are referred to in the RNS Audit Report as the "Current PTF Rules."[5] The Prior PTF Rules and Current PTF Rules are collectively referred to in the RNS Audit Report as the "PTF Rules."[6]

[4] A copy of the Prior PTF Rules is included as Appendix C.3 to the RNS Audit Report submitted herewith.

[5] A copy of the Current PTF Rules is included as Appendix C.4 to the RNS Audit Report submitted herewith. In accordance with the Stipulation, NEPOOL has filed the "Current PTF Rules" with the Commission as part of the 45th Agreement, filed on September 27, 1999, in compliance with the July 30 Order and subsequently accepted for filing effective March 1, 1999 by order dated December 20, 1999 in Docket No. ER99-4531, *New England Power Pool*, 89 FERC ¶ 61,292. On October 21, 2001, NEPOOL filed with the Commission nonsubstantive corrections to the Current PTF Rules as part of the Seventy-Seventh Agreement Amending the

The PTF revenue requirements for the NEPOOL Transmission Owners are calculated based upon the formula and rules as stipulated in the NEPOOL Tariff, specifically in Attachment F and the Attachment F Implementation Rule, both of which were approved by the Commission in the July 30 Order approving the Settlement Agreement. Attachment F and the Attachment F Implementation Rule, along with the PTF Rules, are referred to collectively in the RNS Audit Report and herein as the "Controlling Document."[7]

To complete the audit required by Section 6 of the Stipulation (the "RNS Audit"), ISO-NE engaged Rhema Services, Incorporated ("RSI"). RSI was tasked to perform the RNS Audit pursuant to an audit scope document jointly approved by ISO-NE and NEPOOL (the "RNS RFP") and an agreement between ISO-NE and RSI. A copy of the RNS RFP is included as Attachment 3 hereto. The RNS RFP provides, among other things, that the RNS Audit be "managed by ISO-NE" and that "both ISO-NE and [NEPOOL] will assist the auditor as necessary."[8]

With respect to auditing the RNS revenue requirements, Section 4.1(a) of the RNS RFP provides that the objective of the RNS Audit was to:

> Verify that each Participant[']s costs for PTF agree with their FERC Form 1, and other supporting documentation, and meet the requirements of [the Controlling Document]. For

---

Restated NEPOOL Agreement, Docket No. ER02-145-000 (the 77th Agreement). Those corrections were accepted for filing by letter order dated November 20, 2001. The portion of the 77th Agreement showing the changes made to the text of the Current PTF Rule as filed in the 45th Agreement is included as Attachment 2 to this filing letter for information purposes.

[6] The PTF Rules were sometimes referred to in the Stipulation, Settlement Agreement, the July 30 Order, in the proceedings giving rise to the Stipulation, the Settlement Agreement and the July 30 Order, and in the RNS Audit as "NABS 12."

[7] Attachment F and the Attachment F Implementation Rule as filed per the 45th Agreement are included respectively in Appendices C.1 and C.2 of the RNS Audit Report, filed herewith. As part of its filing of the 77th Agreement, NEPOOL included certain corrections to the Attachment F Implementation Rule as filed in the 45th Agreement. The changes to the Implementation Rule made at that time are reflected in Attachment 2 to this letter, included with this filing for information purposes.

[8] The NEPOOL Transmission Settlement Subcommittee ("TSS") is a subcommittee of the NEPOOL Tariff Committee ("TC") charged specifically with the responsibility for administering the applicable provisions of the Controlling Document and overseeing the development of the Annual Transmission Revenue Requirement pursuant to the Attachment F Implementation Rule. The TSS was tasked with the primary responsibility for addressing RNS Audit-related issues on behalf of the NEPOOL Participants.

> all owners and non-owners of PTF, the data submitted should conform with the intent and principles of the [Controlling Document] and FERC Form 1.

With respect to the NEPOOL RNS Model,[9] Section 4.1(b) of the RNS RFP provides that the objective of the RNS Audit was to:

> For each Participant, verify the clerical accuracy and that the data submitted to ISO-NE on the input document agrees with appropriate supporting documentation.

With respect to PTF cost accounting, Section 4.1(c) of the RNS RFP provides that for each Participant the objective of the RNS Audit was to:

> Verify, through such sampling as appropriate, that each Participant's PTF/non-PTF allocation of transmission plant or substation (as listed in the NEPOOL PTF Catalog)[10], used to develop each Company's PTF allocation factor, conforms to the accounting methods described in the Implementation Rule.

C. The RNS Audit Process

As set forth more fully in the RNS Audit Report, RSI audited the following three major components of the annual RNS rate development:

1. The PTF cost accounting of each Transmission Owner;
2. The RNS revenue requirement of each Transmission Owner; and,
3. The inputs to the NEPOOL RNS Model, which provides the mechanism for ISO-NE to aggregate the Transmission Owner's annual PTF revenue requirement and calculate the RNS rate.

RSI reported that, in performing the RNS Audit, RSI analyzed accounting data, one-line diagrams, and workpapers supporting allocations between PTF and non-PTF; verified the RNS Model inputs for each Transmission Owner against the FERC Form 1 or other supporting accounting data; verified Transmission Support Payments against booked revenues; and verified the coincident peak load data used in the rate design against the FERC Form 1 or other supporting documents.

---

[9] NEPOOL RNS Model is the mechanism used by ISO-NE to aggregate the Transmission Owner's annual PTF revenue requirements and calculate the RNS rate.

[10] The NEPOOL "PTF Catalog" is a listing of all transmission line facilities designated by NEPOOL as PTF during the specific twelve month period covered by a particular PTF Catalog. The PTF Catalog is reviewed annually and updated as necessary by the NEPOOL Reliability Committee ("RC"), subject to approval by the NPC.

As the RNS Audit progressed, a number of questions were raised by RSI, ISO-NE, the NEPOOL TSS, individual investor-owned Transmission Owners (ITOs") and individual Municipal Transmission Owners ("MTOs") regarding the interpretation and application of various aspects of the Controlling Document. Some questions reflected issues that were generic or common to all Transmission Owners, such as the interpretation of the PTF Rules as applied to substations. Other questions were specific to the application of the Controlling Document to groups of Transmission Owners, for example MTOs vs ITOs. Resolution of these types of questions required guidance on how to interpret and apply the Controlling Document in the particular context of that Transmission Owner group. For example, the Implementation Rule had essentially been developed in settlement for application to ITOs and it was generally agreed by RSI, ISO-NE and the TSS that a literal application of some aspects of the Implementation Rule to the MTOs would produce a result that was not consistent with the purpose of the Implementation Rule and, in some cases, would be inequitable. Still other questions reflected issues that were specific to a particular Transmission Owner. Examples include whether the allocation methodology used by a particular Transmission Owner for particular equipment was appropriate.

In order to address these numerous issues, the parties agreed first that the goal of the audit process should be to resolve as many issues as possible before the informational filing was made. The parties also agreed that, for issues that could not be resolved before the informational filing, RSI would complete the audit subject to the participating Transmission Owners' reservation of their right to submit any disagreement they had with RSI's approach and findings to the Commission for resolution in any proceeding commenced to review the RNS Audit Report.

As part of this process, RSI, ISO-NE and the Transmission Owners sought guidance from the appropriate NEPOOL Technical Committees on various issues. One set of issues was submitted to the TC for guidance in January 2001 in the form of a document referred to by the parties as the "Interpretive Guidance Document." The TC reviewed the Interpretive Guidance Document and concurred that it reflected an appropriate approach to resolving the issues identified therein. A copy of the Interpretive Guidance Document is included as Appendix D.1 to the RNS Audit Report, filed herewith.

Following the TC's review, at ISO-NE's request and at NEPOOL Counsel's suggestion, the Interpretive Guidance Document was submitted for informal review and comment to the Commission's Trial Staff who had been involved in the Tariff Docket and assisted in the successful negotiation of the Stipulation and the Settlement Agreement. In March 2001, the Interpretive Guidance Document was reviewed with Trial Staff, who concurred that the approach reflected in the Interpretive Guidance Document was consistent with the intent and spirit of the Implementation Rule and the Settlement Agreement. Consequently, ISO-NE instructed RSI to employ the interpretation provided in the Interpretive Guidance Document for purposes of completing the RNS Audit.

RSI, ISO-NE, the TSS and individual Transmission Owners sought and received additional guidance on other technical issues regarding the interpretation and application of the Controlling Document. These questions were directed to the NEPOOL Reliability Committee ("RC"). The additional guidance provided by the RC in sufficient time for consideration and use in performing the RNS Audit are included in Appendices D.2 and D.3 to the RNS Audit Report. Additional guidance was sought from the RC on the items identified in Attachments 4 and 5 to this filing letter. However, given the constraints of the schedule for completing the RNS Audit, these items were identified too late in the process for full consideration in completing the RNS Audit. The subject matter of these requests may be addressed by one or more Transmission Owners who disagree with RSI's approach to these issues as reflected in the RNS Audit Report. Accordingly, materials pertinent to these requests for guidance are included with this transmittal letter for convenience and information purposes.[11]

In some cases, there was disagreement between RSI and one or more Transmission Owners with respect to RSI's approach to the audit and/or interpretation or application of the Controlling Document. The parties were able to resolve a significant number of those disagreements prior to completion of the audit, but were unable to reach closure on all of them.

As to items on which closure has not been reached, the parties agreed that it would be more efficient to defer resolution of such matters to a single, comprehensive proceeding in which all of the disagreements could be raised and considered together in light of an audit that was otherwise complete as to the areas in which there was agreement. The parties, therefore, agreed that, for purposes of the RNS Audit, a finding that a Transmission Owner was "In Compliance" would mean that RSI was satisfied that the data and the RNS revenue requirement submitted by a Transmission Owner for purposes of the RNS Audit substantially met all of the requirements of the Controlling Document and the Interpretive Guidance Document, as interpreted and applied by RSI.

Although all of the Transmission Owners have been found "In Compliance" for purposes of the RNS Audit, a number of disagreements remain to be resolved. Those Transmission Owners who disagree with RSI's interpretation and/or application of the Controlling Document (and/or Interpretive Guidance) have filed responses to RSI's conclusions regarding their revenue requirement submissions. Those responses identify their specific disagreements with the conclusions reached by RSI in the RNS Audit Report. NEPOOL and ISO-NE anticipate that individual Transmission Owners will intervene in the proceeding designated by the Commission for review of the RNS Audit Report to further advocate or explain their position.

D. Summary of Overall Findings

[11] Attachment 5 reflects that of four (4) additional questions submitted to the RC, the RC was unable to resolve a portion of question number four as submitted. The TSS subsequently revised the wording of that question and requested guidance from the RC on the revised question. The RC has not yet acted on the revised question.

Section 4 of the RNS Audit Report sets forth RSI's overall conclusions regarding recalculation of the RNS rates in effect for each of the cost periods being audited. Those recalculated figures assume that RSI's interpretation and application of the Controlling Document, as reflected in the RNS Audit Report, is affirmed by the Commission in its entirety.

The RNS Audit reveals that, in RSI's opinion, the total NEPOOL RNS revenue requirement for the year 1996, 1997 and 1998 as submitted by the Transmission Owners to ISO-NE in 1999 to effect compliance with the Settlement Agreement understates the audited RNS revenue requirement by $8,181,128 or 1.0%. Of this amount, as reflected in the RNS Audit Report, RSI has concluded that the RNS revenue requirement for the June 1, 1997 through May 31, 1998 rate year is overstated by $3,812,989 (RNS Audit Report, Table 4); the RNS revenue requirement for the June 1, 1998 through May 31, 1998 rate year is understated by $5,685,206 (RNS Audit Report, Table 5); and the RNS revenue requirement for the June 1, 1999 through May 31, 2000 rate year is understated by $6,308,912 (RNS Audit Report, Table 6).[12]

II. DESCRIPTION OF THE RNS AUDIT REPORT

The RNS Audit Report is organized as follows.

1. The "executive summary," in which RSI provides more detail as to RSI and the RNS Audit Process, and explains RSI's overall findings and conclusions.

2. Appendix A to the RNS Audit Report which details the RSI's RNS Audit findings and exceptions for each of the Transmission Owners for each of the three rate years audited. The results for each Transmission Owner are identified in a separate section of Appendix A. Each section of Appendix A, in turn, contains three major subsections described below.

a. Subsection A of each individual Transmission Owner report provides RSI's findings and conclusions as to that Transmission Owner's PTF cost accounting. Subsection A in each report was prepared by RSI.

---

[12] Due to the operation of the Commission-approved transitional arrangements set forth in Schedule 9 of the NEPOOL OATT as well as Commission-approved arrangements regarding pre-and post-restructuring costs, among other things, the dollar amounts of the over- and understatements reflected in Tables 4, 5 and 6 do not correspond to a one-to-one impact on rates charged under the NEPOOL Tariff for RNS service. A Transmission Owner's total transmission revenue requirement for each billing period is collected through a combination of the RNS and the Transmission Owner's local transmission tariffs. Accordingly, to the extent there is an increase in an individual Transmission Owner's PTF revenue requirement under the NEPOOL Tariff, there is a corresponding decrease in the Transmission Owner's local transmission tariff billings. Neither NEPOOL nor ISO-NE have performed the analyses to determine the specific rate impacts of an audit-related rebilling, since those rate impacts will not be known with certainty until after the Commission has issued orders with respect to the audit results submitted with this filing.

b. Subsection B of each individual Transmission Owner report provides RSI's findings and conclusions as to the RNS revenue requirement submissions of that Transmission Owner as well as the accuracy of the inputs to the NEPOOL RNS Model used by that Transmission Owner in those revenue requirement submissions. Subsection B in each report was prepared by RSI.

c. Subsection C of each individual Transmission Owner report provides, to the extent it was provided to RSI, the applicable Transmission Owner's disagreement with RSI's interpretation and/or application of the Controlling Document (and/or the Interpretive Guidance Document). Materials in subsection C of an individual Transmission Owner report were prepared and submitted by the Transmission Owner.

Collectively, subsections A, B and C of the individual Transmission Owner audit reports included in Appendix A to the RNS Audit Report are intended to provide a reader of the RNS Audit Report with the results of RSI's audit of that Transmission Owner, an understanding of the nature of any disagreements that remain to be resolved, the potential dollar magnitude of those disagreements, and the positions of RSI and the Transmission Owner as to the disputed items. NEPOOL and ISO-NE note, however, that submission of materials for subsection C of a Transmission Owner's individual audit report was not a prerequisite for a Transmission Owner challenging any conclusions reached in the RNS Audit Report, or a substitute for pursuing any such challenge in proceedings before the Commission. As agreed in the process of completing the RNS Audit, regardless of whether it has submitted comments for inclusion in subsection C of its individual Transmission Owner audit report, each Transmission Owner has fully reserved its rights to challenge the RNS Audit Report, and to participate fully in any judicial or administrative proceeding commenced with respect to the RNS Audit Report, including but not limited to responding to or commenting upon challenges raised or positions taken by any other participant in any such proceeding.

3. The RNS Audit Report also includes other appendices providing the Commission with various documents utilized in the RNS Audit, including, for example, the Interpretive Guidance Document, other guidance provided by NEPOOL Technical Committees, the Prior and Current PTF Rules, and samples of data requests submitted by RSI to the Transmission Owners.

To the extent that the Commission determines that any filing requirements applicable to this informational filing have not been fully met, NEPOOL and ISO-NE respectfully request that the Commission waive any such requirement in order for this filing to be accepted as filed.

III. REQUEST FOR ASSIGNMENT TO AN ALTERNATIVE DISPUTE RESOLUTION PROCESS

The process implemented by the parties has effectively narrowed the issues in dispute as to which guidance from the Commission is required. The parties have expended significant time, effort and resources to narrow contested issues, but need additional assistance to resolve the remaining issues.

With the benefit of technical input from Commission Staff, the parties may be able to reach closure on many, if not all, of the outstanding issues.[13] Accordingly, NEPOOL and ISO-NE respectfully request that any challenges to the RNS Audit Report not resolved by an initial Commission order with respect to this filing be referred to a settlement judge or other alternative dispute resolution process to determine whether, at the conclusion of that process, there remain any issues which must be resolved through litigation or otherwise.

IV. ADDITIONAL SUPPORTING INFORMATION

In addition to this filing letter and the RNS Audit Report (with appendices as identified therein), NEPOOL and ISO-NE submit the following materials:

Attachment 1	RNS Audit Report (with appendices)
Attachment 2	Excerpt from 77th Agreement filing showing corrections to Attachment F Implementation Rule and Current PTF Rules
Attachment 3	RNS Audit RFP
Attachment 4	Supplemental guidance provided by Reliability Committee (as to questions (1)-(3) inclusive)
Attachment 5	Revised supplemental guidance requested of Reliability Committee
Attachment 6	List of NEPOOL Participants to whom this Informational Filing is being distributed.
Attachment 7	List of parties to the Settlement Agreement
Attachment 8	List of New England governors and utility regulators to whom this Informational Filing is being distributed
Attachment 9	Draft form of Notice concerning this filing that is suitable for publication in the Federal Register in accordance with the Commission's Regulations. A diskette containing this form of notice is also enclosed.

This informational filing has been widely distributed. All Participants members and alternates have been furnished a copy of this filing, together with this transmittal letter and the

[13] NEPOOL and ISO respectfully submit that the settlement process will be facilitated if Commission Trial Staff involved in negotiating the Stipulation and Settlement Agreement could be assigned to assist the parties in resolving the issues submitted for resolution by settlement.

accompanying materials.[14] Attachment 6 of this transmittal letter lists the names and addresses of these representatives of the Participants, which include all the electric utilities rendering or receiving services under the Restated NEPOOL Agreement, as well as each of the independent power producers, power marketers, power brokers, load aggregators, customer-owned utility systems and end users that are currently Participants in NEPOOL. This filing is also provided to the individuals listed on Attachment 7 of this transmittal letter, which identifies the names and addresses of the parties who executed the Stipulation and the Settlement Agreement. This transmittal letter and the accompanying materials have also been sent to the governors and the electric utility regulatory agencies for the six New England states which comprise the NEPOOL Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 8. In accordance with Commission rules and practice, there is no need for the entities identified in Attachments 6, 7 and 8 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

Correspondence and communications regarding this filing should be addressed to the NEPOOL Participants Committee and ISO-NE as follows:

For NEPOOL:

Roberto R. Denis, Chair
NEPOOL Participants Committee
c/o FPL Energy, Inc.
700 Universe Blvd.
Juno beach, FL 33408
Tel: (561) 691-7338
Fax: (561) 694-3650

David T. Doot, Esq.
Scott P. Myers, Esq.
Day, Berry & Howard LLP
CityPlace I
Hartford, CT 06103-3499
Tel: (860) 275-0361
Fax: (860) 275-0343

For ISO New England Inc.:

James H. Douglass, Esq.
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
Tel: (413) 540-4559
Fax: (413) 535-4379

---

[14] Pursuant to changes to Section 21.13(e) of the Restated NEPOOL Agreement, which was accepted by the Commission in *New England Power Pool*, 90 FERC ¶ 61,019 (2000), NEPOOL Participants are being served electronically rather than by hard copy.

Please acknowledge receipt of this filing by date stamping and returning the extra copy of this filing to the courier delivering this filing.

Respectfully submitted,

Scott Myers /RVT

David T. Doot, Esq.
Scott Myers, Esq.
Day, Berry & Howard LLP
CityPlace I
Hartford, CT 06103-3499
Tel: (860) 275-0361

Counsel for New England Power Pool
Participants Committee

James Douglass / RVT

James H. Douglass, Esq.
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Counsel for ISO New England Inc.

Attachments
cc: Individuals and entities listed in Attachments 6, 7 and 8

NEPOOL REGIONAL NETWORK SERVICE

AUDIT REPORT

For Rates in Effect
June 1, 1997
Through
May 31, 2000

April 19, 2002

Prepared by Rhema Services Inc.

NEPOOL RNS Rate Audit Report

Table of Contents

NEPOOL RNS Rate Audit Report

1. Introduction

On April 4, 2000, Rhema Services Inc. ("RSI", or the "Auditor") was selected by ISO New England, Inc. ("ISO-NE"), through its standard bidding process, to perform an audit (the "RNS Audit") of the Regional Network Service ("RNS") annual rates applicable under the NEPOOL Open Access Transmission Tariff ("OATT") based upon 1996, 1997 and 1998 calendar year data for RNS rates in effect June 1, 1997 through May 31, 1998, June 1, 1998 through May 31, 1999 and June 1, 1999 through May 31, 2000, respectively. RSI is a corporation established in 1981 whose main purpose is to provide consulting services to electric utilities, primarily in the areas of revenue requirement, cost of service and rate design for all phases of utility operations, including transmission operations. The RSI team assigned to this project consists of engineers and accountants with many years of experience in the utility industry. The RSI team has previously performed these type of analyses required for this project and has presented testimony in support of such analyses on numerous occasions before the Federal Energy Regulatory Commission (the "FERC" or the "Commission") and various state public utility commissions.

RSI was engaged by ISO-NE to audit the RNS rates that were in effect for the three annual costing periods and the associated rate application periods shown in Table 1.

Table 1
Annual Costing and Annual Rate Application Periods

Costing Periods	Rate Application Periods
Calendar Year 1996	June 1, 1997 through May 31, 1998
Calendar Year 1997	June 1, 1998 through May 31, 1999
Calendar Year 1998	June 1, 1999 through May 31, 2000

The overall objective of the audit is to assure that the individual Transmission Owners' ("TO") RNS transmission revenue requirement and the resulting NEPOOL rate for RNS have been accurately computed in conformance with the applicable provisions of the NEPOOL OATT. The results of the audit are to be delivered to ISO-NE in the form of a written report, and, also filed as a public informational filing with the FERC pursuant to Section 6 of a stipulation dated February 12, 1999 and entered into by NEPOOL and FERC Trial Staff in Docket Nos. OA97-237-000, et al. (the "Stipulation"), to resolve certain issues between them with respect to the justness and reasonableness of Attachment F of the NEPOOL OATT that had been set for hearing by the FERC by order dated April 20, 1998, New England Power Pool, 83 FERC ¶ 61,045 (1998). The Stipulation was made a part of the settlement agreement (the "Settlement Agreement") reached in that proceeding that was approved by the FERC by order dated July 30, 1999, New England Power Pool, 88 FERC ¶ 61,140 (the "July 30 Order"). A copy of the Settlement Agreement is attached hereto as Appendix B. Section 6 of the Stipulation provides, in pertinent part, as follows:

> The System Operator shall independently audit the charges in effect for the period June 1997 through May 2000, or direct that an audit(s) be conducted under its supervision by an independent third party. Such audit(s) shall verify, through such sampling as appropriate, that Transmission Providers are correctly accounting for PTF investment in accordance with the applicable NEPOOL rules for determining PTF investment. The results of any such audit(s) shall be filed with the Commission as an informational filing, and the charges recalculated to correct any errors identified in such

audit, with refunds and surcharges, as appropriate, for any amounts previously over- or under-charged due to such errors.

The NEPOOL Transmission Settlement Subcommittee ("TSS"), which reports to the NEPOOL Tariff Committee ("TC"), is responsible for the annual review and updates to the RNS rates charged under the NEPOOL OATT. Subject to the Commission-approved phase-in of the RNS rate during the Transition Period as set forth in the NEPOOL OATT, the RNS rate charged for regional transmission service in New England is based upon the total revenue requirement for Pool Transmission Facilities ("PTF") owned and operated by the New England TOs. Generally, PTF includes those transmission facilities rated at 69 kV and above which allow for power to move freely on and across the New England transmission network. NEPOOL developed a set of rules for determining investment to be included in PTF, which is entitled "Rules for Determining Investment to be Included in PTF" (the "PTF Rules"). The PTF Rules in effect for the rate period ending May 31, 1998 are set forth in Appendix C.3 attached hereto (and are referred to herein as the "Prior PTF Rules"). The PTF Rules in effect for rate periods since June 1, 1998 are set forth in Appendix C.4 attached hereto (and are referred to herein as the "Current PTF Rules"). As part of the Stipulation, NEPOOL has filed the "Current PTF Rules" with the Commission. That filing was made in September 1999, in compliance with the July 30 Order. The Prior and Current PTF Rules, collectively, are referred to herein as the "PTF Rules." The PTF Rules were sometimes referred to in the Stipulation, Settlement Agreement, the July 30 Order and the proceedings giving rise to the July 30 Order as "NABS 12."

The revenue requirement for non-PTF are collected through the local transmission tariffs of the individual TOs, and are outside the scope of this audit. The PTF revenue requirement for the TOs are calculated based upon the formula and rules as stipulated in the NEPOOL OATT, Attachment F and the Attachment F Implementation Rule (these provisions along with the PTF Rules, collectively, the "Controlling Document") all of which were approved by the Commission in the July 30 Order and have been filed with the Commission. (Appendix C)

During the audit process, a number of questions regarding the interpretation and application of the Controlling Document were raised by the Auditor, ISO-NE and various TOs. The Auditor identified what it concluded were ambiguities in the language of various provisions of the Controlling Document, which, in the Auditor's opinion, made it difficult for the TOs to follow some of the rules, and, also made the audit process more cumbersome. To address interpretation and application issues arising in the audit process, ISO-NE asked NEPOOL TC to provide guidance on a number of issues concerning the interpretation and application of various provisions of the Controlling Document. The TC provided guidance to help facilitate the audit process. Both the issues and the TC's response are set forth in an Interpretive Guidance Document, a copy of which is attached hereto in Appendix D.1. At the request of ISO-NE, NEPOOL sought an informal review by the Commission Trial Staff who had been involved in the proceedings that led to the Settlement Agreement. The Auditor was advised by ISO-NE that the Commission Trial Staff, during an informal meeting, concurred that the guidance outlined in the Interpretive Guidance Document seemed reasonable and consistent with the spirit and intent of the settlement that had been negotiated. The audit then proceeded in accordance with the Interpretive Guidance Document with respect to the issues that are the subject of that Document. Other interpretation issues or questions were identified and were resolved by following a format agreed upon by ISO-NE and NEPOOL, which permitted the audit to proceed as expeditiously as possible. These issues or questions were submitted to the NEPOOL TC or Reliability Committee ("RC") as appropriate for further guidance. These issues or questions and the responses of the TC and/or RC are set forth in Appendices D.2 and D.3.

There were fourteen (14) NEPOOL TOs that owned PTF with transmission revenue requirement to be audited. These TOs, including their subsidiary utilities, are listed in Table 2.

Table 2
NEPOOL Participants With PTF

1. Bangor-Hydro Electric Company (BHEC)
2. Boston Edison Company (BECO)
3. Braintree Electric Light Department (BELD)
4. Central Maine Power Company (CMP)
5. Commonwealth Electric System (CES)
   a. Cambridge Electric Light Company
   b. Canal Electric Company
   c. Commonwealth Electric
6. Connecticut Municipal Electric Energy Cooperative (CMEEC)
   a. Bozrah
   b. Groton
   c. Norwich
   d. Wallingford
7. Eastern Utilities Associates (EUA)
   a. Blackstone Valley Electric Company
   b. Eastern Edison Company
   c. Montaup Electric Company
   d. Newport Electric Corporation
8. Holyoke Gas & Electric Light Department (HG&E)
9. Fitchburg Gas & Electric Light Company (FG&E)
10. New England Power Company (NEP)
    a. Narragansett Electric Company
    b. New England Power Company
11. Northeast Utilities (NU)
    a. Connecticut Light & Power Company
    b. Holyoke Power & Electric Company
    c. Holyoke Water Power Company

d. North Atlantic Electric Company
e. Public Service Company of New Hampshire
f. Western Massachusetts Electric Company

12. Taunton Municipal Light Plant (TMLP)
13. United Illuminating Company (UI)
14. Vermont Electric Power Company (VELCO)

A complete audit as described in the scope of work by ISO-NE was performed for each of the utilities listed in Table 2 for each of the three calendar years (costing periods), 1996, 1997 and 1998. Additionally, there are thirty-three (33) Participants that do not own PTF, but that do support certain PTF through facilities payments to certain TOs. These payments are derived by those TOs and were examined by the Auditor as part of the audit.

2. Audit Schedule

The RNS audit was commenced on April 12, 2000 with the Auditor's submittal of an initial data request to the TOs. The initial RNS audit schedule was revised on a number of occasions and Table 3 below depict the combined high-level milestones of the RNS audit schedule as it finally unfolded.

Table 3
Audit Schedule

Milestones	Dates
1. Initial Request for Information from the TOs	April 12, 2000
2. Initial Draft Audit Report	September 1, 2000
3. Final Response to All Data Requests	November 16, 2001
4. Final Draft Audit Report	January 18, 2002
5. Final Audit Report Issued to ISO-NE	April 19, 2002

3. Audit Approach

This project is an audit of compliance with defined rules that have been agreed to by NEPOOL Participants and approved by the Commission. The Auditor applied the rules governing this audit consistently to all TOs and also requested similar supporting documentation from each TO to verify the accuracy of their RNS Revenue Requirement. The sources of the underlying data are primarily FERC Form 1 Reports ("FF#1") that are based on audited information and are attested to by a corporate officer of the investor owned TOs, or Annual Reports that are submitted to other regulatory agencies, as is the case with municipally owned utilities. The information contained in these reports is typically audited annually.

This RNS Audit is a verification that the defined and agreed upon rules as set forth in the Controlling Document and the TC and RC interpretive guidance are followed in allocating the TOs' transmission facilities between PTF and non-PTF, in setting the revenue requirement for the RNS rate development and in developing the ultimate rates actually charged for RNS pursuant to the NEPOOL OATT, Schedule 9.

The three major components of the annual RNS rate development that were audited are as follows:

1. The PTF cost accounting of each TO in accordance with the Controlling Document, and the TC and RC interpretive guidance (see Section A of each of the individual TO audit results);
2. The RNS revenue requirement of each TO in accordance with the Controlling Document, and the TC and RC interpretive guidance (see Section B of each of the individual TO audit results); and,

3. The inputs to the NEPOOL RNS Model, which provides the mechanism for ISO-NE to aggregate the TOs' annual transmission revenue requirement and calculate the RNS rate, in accordance with Schedule 9 of the NEPOOL OATT (see Section B of each of the individual TO audit results).

The Auditor obtained data such as the FF#1, rate formula calculations, etc. from various web sites. After the initial meetings and follow-up discussions with the TSS and with ISO-NE staff, an audit work plan was developed to assist the Auditor in collecting the necessary information to conduct the audit in the most efficient and least intrusive manner possible. Numerous data requests were reviewed by ISO-NE staff and submitted to the TOs. The documentation requested from the TOs, in these data requests, for year ending December 31, 1996 would have permitted a comprehensive review of the separation of PTF and non-PTF facilities and associated investment. The documentation requested, in these data requests, for the years ending December 31, 1997 and December 31, 1998 would have permitted a review of the annual changes that occurred on the transmission system during 1997 and 1998.

The audit was conducted in four steps:

1. Accounting data, one-line diagrams, and workpapers supporting allocations between PTF and non-PTF were analyzed;
2. RNS model inputs were verified for each TO against FF#1 or other supporting accounting data;
3. Transmission support payments were verified against booked revenues; and,
4. The coincident peak load data used in the rate design were verified against FF#1 or other supporting documents.

Based upon the audit of the TO's initial supporting documents, the Auditor issued an initial draft audit report concluding that most TOs' RNS Revenue Requirements were not in accordance with the Controlling Document. In an effort to complete a comprehensive audit of all TOs, the original audit schedule was revised. Subsequently, the TOs submitted revised and updated information that, in the Auditor's opinion, is in accordance with the Controlling Document and the Interpretive Guidance Document.

NEPOOL advised ISO-NE that rather than using Section A of the PTF Rules as filed at FERC, the current NEPOOL PTF Catalog (the "Catalog"), approved by the NEPOOL Reliability Committee ("RC"), and in effect during each of the costing periods under audit, should be utilized for purposes of completing the transmission lines portion of the audit. The use of the Catalog helped to streamline the Auditor's work related to verification of PTF line assignments, but could not be used to verify allocation of station equipment between PTF and Non-PTF. The primary source of guidance on that aspect of the audit was the PTF Rules, and the interpretive guidance provided by the TC and RC.

4. Summary Findings

A detailed discussion of the findings for each TO is attached as Appendix A to this report. Additionally, a matrix, Appendix F, which summarizes the findings and shows at a glance the areas where the Auditor identified findings for each TO that, in the Auditor's opinion, were not in compliance with the Controlling Document. Tables 4, 5 and 6 provide a numerical summary of the RNS Audit results.

The following definitions apply to the items contained in Tables 4, 5 and 6:

The "**Per TO**" column under the section labeled "**RNS Revenue Requirement** $" shows the RNS Revenue Requirement used to develop the RNS rates in effect as submitted by that TO to ISO-NE in accordance with Schedule 9 of the NEPOOL OATT for the applicable costing period. This submittal by each TO is the subject of this audit.

The "**Per Audit**" column under the section labeled "**RNS Revenue Requirement** $" shows the RNS Revenue Requirement submitted by the TO incorporating the Auditor's findings for the applicable costing period.

The "**Difference**" and "**%**" columns show the difference in dollars and percentage in the RNS revenue requirement between the "**Per TO**" and "**Per Audit**" columns. A negative figure indicates that the TO RNS revenue requirement included in the development of the RNS rates in effect as submitted by the TO is **more than** the RNS revenue requirement for that year as audited. A positive figure indicates that the TO RNS revenue requirement included in the development of the RNS rates in effect as submitted by the TO is **less than** the RNS revenue requirement for that year as audited.

The "**Original Filing**" column under the section labeled "**Compliance Status**" shows the Auditor's opinion of the TO RNS Revenue Requirement submittal to ISO-NE used to develop the RNS rates in effect under Schedule 9 of the NEPOOL OATT. This opinion is based upon compliance with the Controlling Document and the interpretive guidance for the applicable costing period.

The "**Audit Filing**" column under the section labeled "**Compliance Status**" shows the Auditor's opinion of the revised RNS Revenue Requirement submitted by the TO incorporating the audit report findings. This opinion is based upon compliance with the Controlling Document and the interpretive guidance for the applicable costing period.

A finding of "**In Compliance**" under the section labeled "**Compliance Status**" means that in the Auditor's opinion, the RNS Revenue Requirement submitted by the TO **is** in compliance with the Controlling Document and interpretive guidance for the applicable costing period.

A finding of "**Out of Compliance**" under the section labeled "**Compliance Status**" means that in the Auditor's opinion, the RNS Revenue Requirement submitted by the TO **is not** in compliance with the Controlling Document and interpretive guidance for the applicable costing period.

Table 4 provides a summary of the RNS Audit results for 1996.

Table 4
Audit Results for 1996

Transmission Owner	RNS Revenue Requirement $ Per TO	Per Audit	Difference	%	Compliance Status Original Filing	Audit Filing
BHEC	$ 1,343,427	$ 904,300	$ (439,127)	-32.7%	Out of Compliance	In Compliance
BECO	41,353,303	35,964,879	(5,388,424)	-13.0%	Out of Compliance	In Compliance
BELD	277,400	174,649	(102,751)	-37.0%	Out of Compliance	In Compliance
CMP	19,812,894	19,812,894	-	0.0%	In Compliance	In Compliance
CES	11,568,798	10,416,303	(1,152,495)	-10.0%	Out of Compliance	In Compliance
CMEEC*	193,226	193,226	-	0.0%	N/A *	N/A *
EUA	9,697,487	11,581,874	1,884,387	19.4%	Out of Compliance	In Compliance
FG&E	602,400	516,583	(85,817)	-14.2%	Out of Compliance	In Compliance
HG&E	817,669	509,677	(307,992)	-37.7%	Out of Compliance	In Compliance
NEP	59,747,893	60,218,587	470,694	0.8%	Out of Compliance	In Compliance
NU	73,572,723	73,889,802	317,079	0.4%	Out of Compliance	In Compliance
TMLP	381,892	247,272	(134,620)	-35.3%	Out of Compliance	In Compliance
UI	23,847,588	25,419,615	1,572,027	6.6%	Out of Compliance	In Compliance
VELCO	13,730,694	13,284,744	(445,950)	-3.2%	Out of Compliance	In Compliance
Subtotal	$256,947,394	$ 253,134,405	$ (3,812,989)	-1.5%		
All Others - (Support Payments, Etc.)	1,855,978	1,855,978	-	0.0%	In Compliance	In Compliance
Total RNS Revenue Requirement	$258,803,372	$ 254,990,383	$ (3,812,989)	-1.5%		

* CMEEC had no PTF facilities prior to 1998. The amounts shown represent support payments only.

Table 5 provides a summary of the RNS Audit results for 1997.

Table 5
Audit Results for 1997

Transmission Owner	RNS Revenue Requirement $ Per TO	RNS Revenue Requirement $ Per Audit	Difference	%	Compliance Status Original Filing	Compliance Status Audit Filing
BHEC	$ 1,551,914	$ 1,058,621	$ (493,293)	-31.8%	Out of Compliance	In Compliance
BECO	41,478,592	41,048,784	(429,808)	-1.0%	Out of Compliance	In Compliance
BELD	233,973	224,541	(9,432)	-4.0%	Out of Compliance	In Compliance
CMP	20,253,750	20,238,193	(15,557)	-0.1%	In Compliance	In Compliance
CES	12,777,981	12,038,301	(739,680)	-5.8%	Out of Compliance	In Compliance
CMEEC*	181,155	181,155	-	0.0%	N/A *	N/A *
EUA	10,163,084	12,866,148	2,703,064	26.6%	Out of Compliance	In Compliance
FG&E	613,183	553,651	(59,532)	-9.7%	Out of Compliance	In Compliance
HG&E	855,631	716,810	(138,821)	-16.2%	Out of Compliance	In Compliance
NEP	72,899,645	73,683,872	784,227	1.1%	Out of Compliance	In Compliance
NU	76,673,464	77,659,588	986,124	1.3%	Out of Compliance	In Compliance
TMLP	367,705	239,724	(127,981)	-34.8%	Out of Compliance	In Compliance
UI	25,718,763	28,024,782	2,306,019	9.0%	Out of Compliance	In Compliance
VELCO	14,661,826	15,581,702	919,876	6.3%	Out of Compliance	In Compliance
Subtotal	$ 278,430,666	$ 284,115,872	$ 5,685,206	2.0%		
All Others - (Support Payments, Etc.)	1,769,226	1,769,226	-	0.0%	In Compliance	In Compliance
Total RNS Revenue Requirement	$ 280,199,892	$ 285,885,098	$ 5,685,206	2.0%		

* CMEEC had no PTF facilities prior to 1998. The amounts shown represent support payments only.

Table 6 provides a summary of the RNS Audit results for 1998.

Table 6
Audit Results for 1998

Transmission Owner	RNS Revenue Requirement $ Per TO	RNS Revenue Requirement $ Per Audit	Difference	%	Compliance Status Original Filing	Compliance Status Audit Filing
BHEC	$ 1,303,595	$ 1,036,081	$ (267,514)	-20.5%	Out of Compliance	In Compliance
BECO	44,589,299	45,122,214	532,915	1.2%	Out of Compliance	In Compliance
BELD	225,002	260,688	35,686	15.9%	Out of Compliance	In Compliance
CMP	19,782,466	19,943,795	161,329	0.8%	In Compliance	In Compliance
CES	12,958,931	12,098,017	(860,914)	-6.6%	Out of Compliance	In Compliance
CMEEC	782,540	397,450	(385,090)	-49.2%	Out of Compliance	In Compliance
EUA	11,107,126	10,780,606	(326,520)	-2.9%	Out of Compliance	In Compliance
FG&E	163,056	158,429	(4,627)	-2.8%	Out of Compliance	In Compliance
HG&E	814,474	692,501	(121,973)	-15.0%	Out of Compliance	In Compliance
NEP	73,553,319	78,506,231	4,952,912	6.7%	Out of Compliance	In Compliance
NU	76,595,125	76,995,004	399,879	0.5%	Out of Compliance	In Compliance
TMLP	336,342	219,695	(116,647)	-34.7%	Out of Compliance	In Compliance
UI	24,360,619	26,707,568	2,346,949	9.6%	Out of Compliance	In Compliance
VELCO	14,232,470	14,194,997	(37,473)	-0.3%	Out of Compliance	In Compliance
Subtotal	$ 280,804,364	$ 287,113,276	$ 6,308,912	2.2%		
All Others - (Support Payments, Etc.)	1,671,701	1,671,701	-	0.0%	In Compliance	In Compliance
Total RNS Revenue Requirement	$ 282,476,065	$ 288,784,977	$ 6,308,912	2.2%		

As shown in Tables 4, 5 and 6, one (1) of the twenty-eight (28) entities, fourteen (14) TOs and their subsidiaries, were in compliance with the Controlling Document after the initial audit. Tables 4, 5 and 6 also shows, based upon the revised RNS revenue requirements and the appropriate detailed documentation submitted by the TOs, in the Auditor's opinion, all TOs are now in compliance with the Controlling Document and the interpretive guidance for the audit years 1996, 1997 and 1998. In the aggregate for the three costing periods based upon the audit results, the Auditor concluded that the Total RNS Revenue Requirement is understated by $8,181,129 or by 1.0%.

TABLE OF CONTENTS

NEPOOL RNS RATE AUDIT REPORT

Appendix A

Individual Audit Results

April 19, 2002

Prepared by Rhema Services Inc.

NEPOOL RNS RATE AUDIT

Appendix A
Individual Audit Results

Table of Contents

Appendix A
Individual Audit Results

Table of Contents

Appendix A
Individual Audit Results

Table of Contents

Appendix A

A.1 Bangor Hydro Electric Company (BHEC)

a. PTF and Non-PTF Findings

BHEC provided adequate one-line diagrams to facilitate an assessment of their PTF eligible facilities. Four 115 kV transmission lines, with a total length of 24.9 miles, have been identified in the NEPOOL Catalog as PTF facilities. Two substations contain PTF eligible facilities, namely Graham and Orrington. The Orrington Substation is a jointly owned substation with Central Maine Electric Company. Based on the information provided, the BHEC portion consists of one 345/115 kV transformer, one 345 kV breaker and one 115 kV breaker. The Graham Substation provides seven 115 kV line terminal positions (two 115 kV PTF lines, two non-PTF 115 kV lines and three positions for 115/46 kV transformers) and one 46 kV terminal position. Reportedly, two of the 115/46 kV transformer banks are located outside the Graham Substation fenced area at the adjacent Graham Veazie Substation and one of the 115/46 kV transformer banks and the 46 kV breaker is located in the Graham Substation.

The four lines are reported as PTF eligible facilities for 1996, 1997 and 1998. An analysis of shared right-of-way use to allocate a portion of the right-of-way to a 46 kV line was provided. Although the lines are rated at 115 kV, four entries totaling $15,843 ($6,144, $6,516, $2,885 and $298) were noted for 69 kV and 46 kV insulators. Except for the above noted items, the Auditor takes no exception to the PTF data provided for these transmission lines and associated right-of-way.

BHEC provided itemized data for the Orrington and Graham Substations. Orrington, except for incidental facilities, is all PTF while the Graham Substation contains both PTF and non-PTF facilities. In many cases, the itemized data provided for the Graham Substation did not have sufficient description to ascertain a PTF or non-PTF determination. Under the PTF Rules in effect for 1996, 2.5 of the ten 115 kV breaker positions should be allocated to PTF. BHEC allocated their reported 1996 breaker costs on the basis of a ratio of 2.5 to 8, reportedly because their accounting records only contained descriptive information to identify 8 breakers rather than the 10 identified on the substation one-line diagram. Also, the T9 transformer located within the fenced area should be assigned to non-PTF.

In addition, at the Graham Substation, single entries were provided as common facilities for the substation package in the amounts of $1,015,967, $1,040,554 and $1,043,016 for 1996, 1997 and 1998, respectively. This was labeled as the low profile breaker and a half substation package. Combining this amount of costs into a single entry that covers more than one-fourth of the total cost of the Graham Substation, is not accepted by the Auditor. BHEC indicated the since there were no detailed workpapers available for these items, BHEC used the Boggy Brook Station (purchased in 1999) as a backbone or proxy for allocation of the Graham Substation costs. Although there is no basis for using a 1999 proxy station, for purposes of this audit, the Auditor reviewed the information provided for the Boggy Brook Station and found the data to be inadequate. BHEC should use the number of PTF terminals (2 out of 8) as specified in PTF Rules, Section B, Paragraph 8 to allocate the amounts in question.

Initially, BHEC did not provide description details for its post-96 plant in service. BHEC provided copies of invoices for 1997 and 1998 plant additions with no calculation or summary of PTF/non-PTF plant in service. The post-96 plant in service calculations for 1997 and 1998 are out of compliance. The pre-97 PTF plant in service is out of compliance for 1996, 1997 and 1998. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance in accordance with Section II.A.2, NEPOOL Tariff, Attachment F. The Auditor requested documentation that follows the methodology employed in the Settlement Agreement FERC filing in accordance with the Interpretative Guidance Document and a certification from the comptroller. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission PTF plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. Accumulated Deferred Income Taxes are out of compliance with Section II.A.1.(e), NEPOOL Tariff, Attachment F. Implementation Rule states: *Transmission Related Accumulated Deferred Taxes shall equal the Transmission Provider's electric balance of Total Accumulated Deferred Income Taxes multiplied by the PAF factor and further multiplied by the PTF allocation factor.* The Interpretive Guidance Document states: *accordingly, as a general rule, functionalized data is preferred over allocated data, and the purpose of the audit with respect to the functionalized data should be determined whether there is adequate documentation to support the functionalization.* BHEC used a

functionalized number in their revenue requirement filing in the amount of $30,662,910 for Accounts 281-283 and $10,754,847 for Account 190. BHEC provided a workpaper labeled Attachment P, Exhibit 13 deriving these amounts. The Auditor is unable to verify or audit the rationale for assigning certain costs directly to transmission. In addition, BHEC incorrectly applied the PAF allocation in their revenue requirement filing to the functionalized Transmission-related portion of Accumulated Deferred Income Tax. Using the FF#1 data on pages 113 and 111, the amounts shown on those pages are $89,422,297 (281-283) and $17,965,282 (190). Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

4. Other Regulatory Assets/Liabilities is out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F. BHEC did not include FASB 109 costs shown on FF#1, page 232 of $28,993,177. BHEC also did not include any Regulatory Liabilities shown on FF#1, page 278 of $5,828,086 for FASB 106 and $8,445,642 for FASB 109. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Taxes is out of compliance with Section II.E., NEPOOL Tariff, Attachment F. BHEC incorrectly double counted the calculation of property taxes by calculating the total Property Tax times the PAF

allocation factor for Transmission and then calculated the Property Tax times the Transmission W&S allocation factor. Attachment F rules state the tax expense *shall equal the Transmission Provider's total electric municipal tax expense multiplied by the PAF and further multiplied by the PTF allocation factor.* Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

6. Regulatory Commission Expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. BHEC in their revenue requirement filed $548,172. The FF#1, page 350, lines 1 and 2 indicates FERC assessments should be $513,747. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

7. BHEC's transmission support payments for 1996 are in partial compliance with Section II.K., NEPOOL Tariff, Attachment F. Worksheet 7 of BHEC's revenue requirement filing indicated BHEC paid $301,410. The workpapers BHEC provided show BHEC paid $288,042. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

BHEC filed a revenue requirement of $1,343,427 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, BHEC is out of compliance. Subsequently, BHEC submitted an updated revenue requirement of $904,300 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BHEC is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission PTF plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. Accumulated Deferred Income Taxes are out of compliance with Section II.A.1.(e), NEPOOL Tariff, Attachment F, as explained in 1996 3. above. BHEC in their revenue requirement filing used $30,358,134 for Accounts 281-283 and $11,519,616 for Account 190. Using the FF#1 data on pages 113 and 111, the amounts shown on those pages are $87,784,328 (281-283) and $16,159,865 (190). Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

4. Other Regulatory Assets/Liabilities are out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F. BHEC included $60,923,840

from FF#1, page 232, line 15 which is Maine Yankee Decommissioning costs. BHEC did not include FASB 109 costs shown on FF#1, page 232 of $32,116,456. BHEC did not include any Regulatory Liabilities shown on FF#1, page 278 of $6,375,324 for FASB 106 and $9,972,246 for FASB 109. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

6. Regulatory Commission Expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. BHEC in their revenue requirement filed $798,406. The FF#1, page 350 indicates FERC assessments are $500,365. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

7. Transmission support payments are in partial compliance with Section II.K., NEPOOL Tariff, Attachment F. BHEC's revenue requirement filing indicated BHEC paid $304,321 in 1997. The workpapers BHEC provided show BHEC paid $278,231. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

BHEC filed a revenue requirement of $1,520,894 for Pre-97 and $31,020 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, BHEC is out of compliance. Subsequently, BHEC submitted an updated revenue requirement of $1,052,744 for Pre-97 and $5,877 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BHEC is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission PTF plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. Accumulated Deferred Income Taxes are out of compliance with Section II.A.1.(e), NEPOOL Tariff, Attachment F, as explained in 1996 3. above. BHEC in their revenue requirement filed $72,496,043 for Accounts 281-283 and $16,854,374 for Account 190. Using the FF#1 data on pages 113 and 111, the amounts shown on those pages are $95,755,480 (281-283)

and $17,100,734 (190). Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

4. Other Regulatory Assets/Liabilities are out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F. BHEC did not include FASB 109 costs shown on FF#1, page 232 of $32,631,236. BHEC did not include any Regulatory Liabilities shown on FF#1, page 278 of $6,976,023 for FASB 106 and $9,618,159 for FASB 109. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

6. Regulatory Commission Expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. BHEC in their revenue requirement filed $737,708. The FF#1, page 350, lines 1 and 2, indicates FERC assessments are only $676,679. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

7. BHEC's transmission support payments are in partial compliance with Section II.K., NEPOOL Tariff, Attachment F. BHEC's revenue

requirement filing shows BHEC paid $295,247 in 1998. The workpapers BHEC provided show BHEC paid $271,716. Subsequently, BHEC submitted updated information that, in the Auditor's opinion, is in compliance.

BHEC filed a revenue requirement of $1,257,405 for Pre-97 and $46,190 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, BHEC is out of compliance. Subsequently, BHEC submitted an updated revenue requirement of $1,025,264 for Pre-97 and $10,817 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BHEC is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Below are Bangor Hydro-Electric Company's ("BHEC" or "the Company") comments in response to the final audit report. BHEC's comments pertain to the auditor's PTF and Non-PTF Findings. Specifically, BHEC does not agree with the auditor's finding that "BHEC should use the number of PTF terminals (2 out of 8) as specified in PTF Rules, Section B, Paragraph 8 to allocate the amounts in question [the PTF and Non-PTF facilities in the Graham Substation]." Additionally, BHEC reserves its right to object to all the auditor's conclusions in a filing with the Federal Energy Regulatory Commission ("FERC"). BHEC also reserves its right to comment on any Responses filed or positions taken by any other transmission owner in any dispute that arises after the informational filing of the audit report is made with FERC.

1. Comment one refers to the following section and comment.

    A. Audit Exceptions for PTF and Non-PTF Findings – third paragraph, second sentence, which is located on page 6 of Appendix A.

    "*In many cases, the itemized data provided for the Graham Substation did not have sufficient description to ascertain a PTF or non-PTF determination.*"

    Response:

    The descriptions of the itemized data provided by the Company came directly from the plant accounting database. There are thousands of entries in this database and some of those entries may not have sufficiently specific descriptions.

    The Company's accountants and engineers reviewed the accounting information in much detail and were able to describe in detail the equipment in the Company's PTF substations. The Company spent time and effort going over the details of the substation with the auditor.

2. Comment two refers to the following section and comment.

A. Audit Exceptions for PTF and Non-PTF Findings – the entire fourth paragraph, which is located on page 6-7 of Appendix A.

"*In addition, at the Graham Substation, single entries were provided as common facilities for the substation package in the amounts of $1,015,967, $1,040,554 and $1,043,016 for 1996, 1997 and 1998, respectively. This was labeled as the low profile breaker and a* *half substation package. Combining this amount of costs into a single entry that covers more than one-fourth of the total cost of the Graham Substation, is not accepted by the Auditor. BHEC indicated the since there were no detailed workpapers available for these items, BHEC used the Boggy Brook Station (purchased in 1999) as a backbone or proxy for allocation of the Graham Substation costs. Although there is no basis for using a 1999 proxy station, for purposes of this audit, the Auditor reviewed the information provided for the Boggy Brook Station and found the data to be inadequate. BHEC should use the number of PTF terminals (2 out of 8) as specified in PTF Rules, Section B, Paragraph 8 to allocate the amounts in question.*"

Response:

As explained to the auditor, the substation package referred to in this comment was purchased as a single item. The manufacturer and seller did not describe the item by its component parts and they provided only a brief description of the item. Therefore, at the time of purchase, the Company could not provide a cost estimate of the individual components of the substation package and, thus, placed the substation package into the common equipment category.

The Auditor did not accept the entry of the substation package into common plant because it "*covers more than one-fourth of the total cost of the Graham Substation*". There is no basis in the rules for determining PTF investment to preclude an item from being considered common plant because it represents approximately one-quarter of the total investment in a substation. Because the substation package represents less than one-half of the plant gross investment in the Graham substation, it is appropriate to include it as common plant based upon the RC's guidance that a common plant item must be allocated based on PTF terminal count if it represents over one-half of the total gross plant investment in a shared Pool Transmission Facility. The Auditor found that BHEC should use the number of PTF terminals to allocate the costs. The Auditor's finding is incorrect and should be rejected. The Company should be allowed to include the substation package in the Graham substation as common plant.

Because the Auditor rejected BHEC's inclusion of the substation package as common plant, BHEC suggested during a teleconference with the Auditor using a proxy for allocating the Graham substation package based on a similar substation that was constructed with individually purchased components. In an attempt to have the Auditor find BHEC in compliance, the Company pursued the proxy approach. The auditor did not accept the use of a proxy for allocation and instead required BHEC to use number of PTF terminals for allocating the costs.

Auditor's Response:
No response to the TO comment.

A.2 Boston Edison Company (BECO)

a. PTF and Non-PTF Findings

BECO provided an adequate system diagram that was color coded to specifically identify the PTF and non-PTF lines. Substation one-line diagrams were reduced and in some instances information that was needed to cross check individual breakers and line terminal information was not fully legible. These diagrams had notations inserted to depict assumptions made on the separation of PTF and non-PTF facilities from BECO's initial work, which in some instances differed from the PTF and non-PTF cost separations shown in the final work product.

At the start of the audit, BECO's substation records were maintained in a hand-written format on ledger cards. Typically, several hundred cards were associated with a given substation. BECO's initial submittal was made following Rule 8, which simply allocated total substation costs on the basis of the ratio of PTF terminals to the sum of PTF and non-PTF terminals. Since the detailed records were available to allow a detailed separation, it was concluded that BECO could provide a detailed analysis. BECO then entered their records into a spreadsheet format and submitted their comprehensive analysis. This final submittal was found to be adequate for the Auditor's review.

Appendix A

The 1996 substation costs were evaluated in detail for 18 substations. A number of changes were identified, the accumulated impact of these changes resulted in a proposed net reduction of the allowable PTF substation investment of $4,330,028, or 3.74%, from $115,845,180 per the BECO analysis to $111,515,152 per the Auditor's analysis. Ten of the larger substations were evaluated under the revised rules in effect for 1997. Again, the Auditor took exception to certain cost allocations. Minimal network changes occurred between 1997 and 1998, and the Auditor believes that the issues raised relative to the 1997 assessment also apply to the 1998 submittal. Since the analysis was provided in a spreadsheet format, the Auditor was able to highlight the proposed changes and return the updated file to BECO for their review.

The exceptions noted by the Auditor are listed below:

1. Certain cost items that could be attributed to PTF or non-PTF categories based on breaker numbers, transformer numbers or line numbers were not always properly assigned. The Auditor suggested revisions it deemed to be appropriate. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

2. Cost items that could be attributed to PTF or non-PTF categories based on voltage information were not always properly assigned. Facilities of 14

kV or less are assumed to be non-PTF by the Auditor unless specifically identified as station service facilities. The Auditor suggested revisions that it deemed to be appropriate. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

3. Cost items that could be attributed to PTF or non-PTF based on descriptive information such as static condenser, reactor, 4" diameter bus, or bus-supporting structure appeared to not always be properly assigned. The Auditor suggested revisions that it deemed to be appropriate. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Some PTF transformers (345/115 kV, 230/115 kV and phase shifting transformers) were included in the common facility category. The Auditor suggested revisions that it deemed to be appropriate. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

5. The Auditor notes that a number of distribution substations that appear to contain facilities that became PTF eligible under the revised rules in effect for 1997 and 1998 were not included in the cost analysis. The substations in question are numbers 391, 433, 455 and 533 (Burlington, Speen Street, West Framingham and Lexington, respectively). Subsequently, BECO

submitted updated information that, in the Auditor's opinion, is in compliance.

6. One area of some concern is that approximately $36 Million of unclassified plant is recorded on BECO's books or approximately 19% of the total substation plant for each year examined. Out of the $36 Million, $24 Million of unclassified plant has been assigned to PTF plant using the ratio of identified PTF plant to the sum of the identified PTF and non-PTF plant for each individual substation. The Auditor was unable to verify, in accordance with the PTF rules, the reasonableness of the allocation of this significant amount of plant. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

In the Auditor's opinion, the originally filed PTF plant in service was out of compliance with the rules for 1996, 1997 and 1998. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. BECO acknowledged they used beginning of year balances and that year-end balances should have been used in the calculation of the cost of capital. In addition, BECO was asked to provide

their cost of capital calculations that were filed and accepted at FERC in the settlement agreement. The workpaper initially provided by BECO did not support the original filing or what was filed at FERC in the settlement agreement. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

2. The original PTF Transmission Plant filed by BECO is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

3. Property Tax is in partial compliance with Section II.E., NEPOOL Tariff, Attachment F. BECO deviated from the implementation rules and used functionalized data instead of using the formula. Per the Interpretative Guidance Document, this is acceptable provided the functionalized data ties to the FF#1 data. BECO provided a workpaper showing their functionalization. The workpaper provided shows that BECO incorrectly functionalized $90,832,643 from FF#1, page 262, line 23, column (d). BECO should have provided a workpaper to show the functionalization of $90,716,036 from FF#1, page 263, line 23, column (i) for FERC Account 408.1. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission O&M expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F. BECO excluded the total amount of $14,570,085 for Rent expense for Account 567. However, Attachment F rules excludes only *...all HQ HVDC expenses booked to Accounts 560 through 573 and expenses already included in Transmission Support Expense ... which are included in FERC Account Nos. 560-573.* Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

5. Regulatory Commission Expense is in partial compliance with Section II.H., NEPOOL Tariff, Attachment F. Per the Interpretative Guidance Document, Implementation Rule: *Section II.H(3) provides that total FERC assessments shall be multiplied by the Plant Allocation Factor. Accordingly, it is appropriate to include all Account 928 FERC assessments. The Implementation Rule does not require that a portion of the Account 928 FERC assessments to be carved out or segregated before allocation as provided in Section II.H(3).* BECO used $280,474, from FF#1, page 351, column (h), line 2 only. BECO should have used the amounts shown on lines 2 and 3 which total to $255,481. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

6. Plant Allocation Factor is in partial compliance with Section I.A.3., NEPOOL Tariff, Attachment F. BECO used $4,153,358,517 for Total Plant In Service which is the beginning year balance. The FF#1, page 207, line 84, column (g) shows the end of year Total Plant in Service to be $4,231,341,741. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

BECO filed a revenue requirement of $41,353,303 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, BECO is out of compliance. Subsequently, BECO submitted an updated revenue requirement of $35,964,879 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BECO is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

2. The original PTF Transmission Plant filed by BECO is out of compliance. See Section A above for detailed explanation of the finding. Subsequently,

BECO submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Accumulated Depreciation is in partial compliance with Section II.A.1.(d), NEPOOL Tariff, Attachment F. BECO in their revenue requirement filed $153,611,283. The FF#1, page 219, line 23 reports $153,677,138. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Depreciation Expense is in partial compliance with Section II.B., NEPOOL Tariff, Attachment F. BECO in their revenue requirement filed $7,272,402. The FF#1, page 336, line 7 reports $7,175,561. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Tax is in partial compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 3. above. BECO functionalized $92,864,082 from FF#1, page 262, line 23, column (d). BECO should have provided a workpaper to showing the functionalization of $92,754,124 from FF#1, page 263, line 23, column (i). Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission O&M expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 4. above. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

7. Plant Allocation Factor is in partial compliance with Section I.A.3., NEPOOL Tariff, Attachment F. BECO included $1,682,890 for Transmission Related General Plant. The Transmission related General Plant should be $1,554,709. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

BECO filed a revenue requirement of $41,239,475 for Pre-97 and $239,117 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, BECO is out of compliance. Subsequently, BECO submitted an updated revenue requirement of $40,808,035 for Pre-97 and $240,749 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BECO is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, BECO

submitted updated information that, in the Auditor's opinion, is in compliance.

2. The original PTF Transmission Plant filed by BECO is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission O&M expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 4. above. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Plant Allocation Factor is in partial compliance with Section I.A.3., NEPOOL Tariff, Attachment F. BECO included $1,682,890 for Transmission Related General Plant. The Transmission related General Plant should be $1,490,002. Subsequently, BECO submitted updated information that, in the Auditor's opinion, is in compliance.

BECO filed a revenue requirement of $43,431,915 for Pre-97 and $1,157,384 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, BECO is out of compliance. Subsequently, BECO submitted an updated revenue requirement of $43,952,728 for Pre-97 and

$1,169,486 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BECO is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Boston Edison Company has no comment at this time regarding the audit results as reported herein. However, Boston Edison Company expressly reserves its right to submit written comments and to otherwise participate in any proceeding at the Federal Energy Regulatory commission regarding this audit.

Auditor's Response:
No response to the TO comment

A.3 Braintree Electric Light Department (BELD)

a. PTF and Non-PTF Findings

BELD provided adequate one-line diagrams. The system is operated normally open at Station 10 (Middle St. Sub) and, therefore, does not provide a parallel network path. BELD has more than 25 MW of generation at Potter Station. Thus, under the PTF Catalog and under Section A, #3.b. of the PTF Rules the portion of the BELD 115 kV transmission system that consists of a single line from the point of connection on the transmission network (Station 11) to the first bus (Station 16) within the Participant's system is PTF eligible. In addition to the noted facilities, BELD, in its initial submittal, identified the portion of the system between Station 16 and Station 10 as PTF. The Auditor took exception to this because under the PTF Catalog and the example of Section 5.a. of the PTF Rules, radial lines to local load are to be excluded from the PTF.

The Auditor verified against the PTF Catalog that only a portion of the facilities BELD sought to include were PTF eligible. The PTF eligible facilities include the tap point to BECO (Station 11); the actual tap consisting of a 0.23 mile section of overhead 115 kV and a 0.49 mile section of underground 115 kV line between the BECO tie point and Station 16; and, the 115 kV ring bus at Station 16 (Potter Generating Station). This determination is consistent with the PTF Catalog that validated the same two sections of 115 kV line. Under the version of the PTF Rules applicable for 1996, one-third of the 115 kV ring bus at Station 16 qualifies, while under the subsequent version of the

PTF Rules, applicable for 1997 and 1998, the entire 115 kV ring bus at Station 16 qualifies.

Accounting data was requested by FERC account and by substations and transmission line with the totals by FERC account agreeing to the amounts shown in the Annual Report. BELD's total transmission plant in service accounting ledger sheets were provided by FERC account. However, a detailed breakdown by FERC account, transmission line or substation was not provided. A detailed analysis by substation was provided based upon the ledger sheets, but not by FERC account. In addition, during meetings between the Auditor and BELD, BELD was reminded that the data should be in PTF, non-PTF, common and transformer costs categories. Some additional information was provided by BELD, but not in the form requested. This presentation and format was requested from all the TOs. Based on the data provided, the Auditor was unable to verify 1997 and 1998 PTF plant in service because BELD did not provide summaries and allocations of their ledger sheets.

In addition, the transmission land cost should have been broken down between lines and substations. The lines' portion should have been allocated as per Attachment F, Section C (Right of Way). This was not done.

Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. The DPUC Annual Report, page 10, line 26 shows this to be $133,653. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II.A.1. (i), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. Based on the Interpretative Guidance Document, BELD should have used $283,113 times the PAF times the PTF factor.

Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. BELD omitted payroll tax expenses from their revenue requirement calculations. BELD should include these expenses. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

BELD filed a revenue requirement of $277,400 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, BELD is out of compliance. Subsequently, BELD submitted an updated revenue requirement of $174,649 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BELD is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. The DPUC Annual Report, page 10, line 26 shows this to be $133,653. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. Based on the Interpretative Guidance Document, BELD should have used $245,590 times the PAF times the PTF Factor. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F as explained in 1996 5. above. BELD should include these expenses. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

BELD filed a revenue requirement of $233,973 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, BELD is out of compliance. Subsequently, BELD submitted an updated revenue requirement of $224,541 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BELD is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. The DPUC Annual Report, page 10, line 26 shows this to be

$187,401. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. BELD in their revenue requirement filed $0. Based on the Interpretative Guidance Document, BELD should have used $809,684 times the PAF times the PTF Factor. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F as explained in 1996 5. above. BELD should include these expenses. Subsequently, BELD submitted updated information that, in the Auditor's opinion, is in compliance.

BELD filed a revenue requirement of $225,002 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, BELD is out of compliance. Subsequently, BELD submitted an updated revenue requirement of $260,688 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, BELD is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Braintree Electric Light Department ("BELD") disagrees with the audit report on a number of substantive issues.

On July 31, 2001, following its timely initial submittal of information to the Auditor, BELD supplemented its submittal in response to preliminary comments by the Auditor by providing the Auditor with a significant amount of detail information from their accounting records in a format that BELD continues to believe is sufficient to have amply fulfilled the Auditor's requirements.

BELD provided sufficient information to resolve issues as to the treatment of costs for every account except for accounts 354 and 356. RSI recommended allocating the investment in these accounts on the basis of a ratio of PTF overhead line mileage to total overhead lines. Given that the plant has been booked by line and then functionalized as either PTF or non-PTF, BELD believes it is illogical to treat the investment as if it were common plant that needs to be allocated to PTF and non-PTF.

During discussions to address this issue the Auditor stated that he did not have sufficient detail to determine whether the plant being assigned to PTF was in fact PTF plant. BELD was unable to satisfactorily resolve this issue with the Auditor within the confines of the audit schedule. Soon thereafter, BELD was prepared to demonstrate from the material provided that for account 354 – Towers and Fixtures, there are five ledger entries: one to Station 9, one to Station 4, two to Station 16 and one to Station 11; that the accompanying one line diagram shows that Station 16 is an above ground substation and Station 11 which is the line by which the Potter Generating Station interconnects with the NEPOOL PTF system; and that Station 11 is a mix of underground line and overhead lines.

BELD offers the following concluding comments: First, Attachment F to the NEPOOL OATT, the associated Implementation Rule and the PTF Cost Allocation Rules were developed without consultation with NEPOOL's municipal transmission owners, and without regard for differences between the accounting practices of investor-owned transmission owning utilities and those of their municipal counterparts. More flexibility should have been deployed in the audit in taking these differences into account than was the case. Second, BELD has grave concerns about the processes by which the audit was conducted. Having proven unsuccessful in its effort to seek redress for those concerns in the audit process itself, BELD will reserve those concerns to formal proceedings before the FERC.

Auditor's Response:
BELD, similarly to all other TOs, received a comprehensive data request (Appendix E) from the Auditor on April 12, 2000. This data request listed the required information needed by the Auditor from BELD to audit BELD's RNS revenue requirement submitted

to ISO NE. It is the Auditor's opinion that BELD had sufficient time (April 2000 through Feb 2002) to provide, clarify and explain any information that BELD believed was necessary to satisfy the Auditor's request. The audit process applied to BELD was similar in time and effort to the process applied to all other TOs.

A.4 Central Maine Power Company (CMP)

a. PTF and Non-PTF Findings

CMP provided adequate one-line diagrams and supporting cost data to facilitate an assessment of their PTF eligible facilities.

The EHV PTF transmission remained the same at 184.4 miles in all three years. The lower voltage PTF was at 887.5 miles in 1996 and 1997, then at 879.8 in 1998. A check of the PTF lines in the NEPOOL Catalog was made to the system one-line diagrams. No inconsistencies were noted.

Descriptive entries for individual breakers, breaker foundations, relays, switches, and lightning arresters were adequate and typically allowed associating such equipment with a particular transmission line terminal or transformer. Thus, the descriptive entries permitted a more extensive item-by-item separation of a substantial portion of the data line items between PTF and non-PTF.

Although, the Auditor's review of the various substations found a number of instances where the descriptive information could be interpreted to support a different assignment, the overall net results obtained by CMP's interpretation would be within acceptable limits for this type of detailed and well-documented presentation. The Auditor's analysis was done using CMP's data in electronic format as provided by CMP. This greatly facilitated the data verification. In general, the Auditor finds that CMP's presentation was appropriate and verifiable.

In the Auditor's opinion, CMP's PTF plant in service is in compliance for the years 1996, 1997 and 1998.

b. RNS Template Input Findings

1996

1. Cost of Capital is in partial compliance with the Interpretative Guidance Document and Section II.A.2., NEPOOL Tariff, Attachment F. The Auditor reviewed long term debt as shown on Worksheet 2 against FF#1, page 257. CMP provided a worksheet (Worksheet 12) which shows LTD to be $579,878,960 whereas the FF#1, page 257 shows LTD to be $580,548,960. Interest on long term debt per CMP's Worksheet 12 shows $43,059,740, FF#1, page 257 showed $43,547,386. This changes the weighted cost of long-term debt from 7.426% to 7.501% and the overall cost of capital from 8.932% to 8.970%. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

CMP filed a revenue requirement of $19,812,894 for the rate period 6/1/97 to 5/31/98. In the Auditor's opinion, CMP is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is in partial compliance with the Interpretative Guidance Document and Section II.A.2., NEPOOL Tariff, Attachment F. As

explained in 1996 1. above, the Auditor found the same type discrepancies for 1997. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

2. Property Taxes are in partial compliance with Section II.F., NEPOOL Tariff, Attachment F. The FF#1 on page 263, column (i) shows this amount to be $24,129,645 not $24,403,629 as filed by CMP. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission-related Load Dispatching O&M Expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F. The FF#1 on page 321, column (b) shows this amount to be $829,858 not $839,858 as CMP filed. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

CMP filed a revenue requirement of $20,158,568 for Pre-97 and $95,182 for Post-96 for the rate period 6/1/98 to 5/31/99. In the Auditor's opinion, CMP is in compliance with the applicable rules for the rate period. Subsequently, CMP submitted an updated revenue requirement of $20,143,114 for Pre-97 and $95,079 for Post-96 with supporting documentation that incorporates the above findings.

1998

1. Cost of Capital is in partial compliance with the Interpretative Guidance Document and Section II.A.2., NEPOOL Tariff, Attachment F. As explained in 1996 1. above, the Auditor found the same type discrepancies for 1998. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

2. Property Taxes are in partial compliance with Section II.F., NEPOOL Tariff, Attachment F. The FF#1 on page 263, column (i) shows this amount to be \$23,504,697 not \$23,658,256 as filed by CMP. Subsequently, CMP submitted updated information that, in the Auditor's opinion, is in compliance.

CMP filed a revenue requirement of \$19,627,717 for Pre-97 and \$154,749 for Post-96 for the rate period 6/1/99 to 5/31/00. In the Auditor's opinion, CMP is in compliance with the applicable rules for the rate period. Subsequently, CMP submitted an updated revenue requirement of \$19,787,872 for Pre-97 and \$155,923 for Post-96 with supporting documentation that incorporates the above findings.

c. Participant's Comments and Auditor's Response

Participant's Comments:
With respect to the final NEPOOL Regional Network Service Audit Report, CMP reserves all of its rights, as provided generally under the Federal Power Act and as provided specifically in the terms of the settlement agreement approved by FERC in Docket Nos. OA97-237-000, et al.

Auditor's Response:
No response to the TO comment.

A.5 Com Electric System (CES)

i. Commonwealth Edison Company (CEC)

a. PTF and Non-PTF Findings

CEC provided an adequate system diagram that was color coded to separately identify the PTF and non-PTF lines. Large-sized substation one-line diagrams were provided for most substations. The one-line diagrams contained adequate detail to provide a basis for assessing the division of station equipment between PTF and non-PTF facilities.

In most cases, CEC's substation records provided for audit purposes did not contain a level of descriptive detail that would allow the Auditor to verify the assignment of various items of equipment to the individual line terminals. Accordingly, the audit focused more on the verification of the division of the numbers of breakers, switches, lightning arresters and coupling capacitors between PTF and non-PTF categories. Although CEC's records are maintained in a computer based system, electronic files were not provided that would facilitate the Auditors' assessment of the impact of possible changes in the assignment of equipment among the PTF, non-PTF and common categories. Also, certain line disconnect switches are understood to be accounted for with the transmission cost data. This, in some cases, resulted in a mismatch between the items identified on the substation one-line diagrams and the information reported in the cost records. Although further descriptive detail would have facilitated a more comprehensive audit review, the level of detail in the cost records was found to be adequate for the Auditor's review.

Under the rules in effect for 1996, only four CEC substations contain PTF eligible facilities. Under 1997 rules, 16 substations were reported as having PTF eligible facilities. Cost data was reviewed for 1996 and 1997. Also, changes to the Borne Substation cost and the addition of the Commonwealth Substation costs were made in 1998. The questions developed from a review of the 1996 and 1997 data also apply to the 1998 PTF cost submittal.

The exceptions noted by the Auditors are listed below:

The system one-line diagram for Acushnet shows six lightning arresters. Two of which are shown on PTF Lines, two of which are shown on non-PTF Lines and two of which are shown on the 115 kV side of non-PTF transformers. Reported costs for lightning arresters is assigned $13,803 to PTF and $6,685 to non-PTF, while only two of six lightning arresters appear to relate to PTF lines. Even if the two arresters on the high-side of the step-down transformers have been accounted for as distribution equipment, one would expect a more equal division of costs between the PTF and non-PTF equipment. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

The assignment of costs for the Tremont Substation included 8 data entries totaling $5,420 for foundations related to circuit breakers, wave traps and coupling capacitors that should have been assigned to PTF since all transmission terminals at Tremont relate to PTF lines. Also, the station diagram identifies five PTF breakers, however six breakers are reported in the cost data. Possibly two of the entries relate to a single breaker, or possibly a breaker was replaced without the cost records being fully adjusted to remove the retired equipment. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

Some PTF costs are reported for the North Plymouth Substation. This station does not provide a PTF function, but the reported costs of $51,053 may relate to communication equipment that provides a PTF function. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

The reported costs for the Mendall Road Switching Station is assigned fully to PTF. The station diagram shows four motorized switches, two which operate normally closed in network paths and two which provide line selective switching for a non-PTF line to Crystal Springs. The reported cost data appears to be for control and communication equipment and not the costs of any of the switches. The Auditor believes that the control and equipment costs should be apportioned in part to the non-PTF category. Auditors suggested using Section B, paragraph 8. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

At the Bourne Switching Station, there are three PTF lines and two non-PTF lines terminated. Although, the installation cost for lightning arresters is assigned in part to the non-PTF facilities, all the equipment related costs have been assigned to PTF. The Auditor questions why no assignment of lightning arrester equipment costs was made to the non-PTF category. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

Significant costs for the Commonwealth Switchyard ($2,490,353) were incurred in 1998. This facility does not appear on the 1998 system diagram and no substation drawing was provided. Only three cost entries were provided ($1,067,000 for land, $6,554 for structures and $1,416,126 for station equipment). Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

Based upon the above exceptions, the Auditor finds that the originally filed PTF plant in service for 1996, 1997 and 1998 is in partial compliance.

Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. PTF Transmission Plant and the PTF Transmission Allocation Factor are in partial compliance. CEC included $43,439,595 for PTF investment in the calculation of their revenue requirement. Their workpapers show the PTF amount to be only $38,097,248. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Regulatory Commission Expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. CEC included an amount for Federal and State Transmission Related Expenses and Assessments of $5,506. Based on the workpaper provided by CEC, the Auditor could not verify that this amount is a transmission related expense. No explanation was given for this amount except for "Rich, May, Bilodeau & Flaherty". Also, based on the workpaper provided, it appears that CEC's Account 928 FERC Assessment cost should be $27,398 not $26,346 as filed in the RNS revenue requirement. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. Payroll Tax Expense is out of compliance with Section II.F., NEPOOL Tariff, Attachment F. CEC included an Environmental Tax of $5,238 that

should not be included. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of CEC, a revenue requirement of $7,039,428 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, CEC is out of compliance. Subsequently, CES submitted an updated revenue requirement of $6,251,508 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CEC is in compliance with the applicable rules for the rate period.

1997

1. PTF Transmission Plant and the PTF Transmission Allocation Factor are in partial compliance. CEC included $60,153,349 for PTF investment in the calculation of their revenue requirement. Their workpapers show the PTF amount to be only $56,763,080. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Payroll Tax Expense is out of compliance with Section II.F., NEPOOL Tariff, Attachment F. CEC included an Environmental Tax of $5,238 which should not be included. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of CEC, a revenue requirement of $9,284,838 for Pre-97 and $69,883 for Post-96 for the rate period 6/1/98 to 5/31/99. In the Auditor's opinion, CEC is out of compliance. Subsequently, CES submitted an updated revenue requirement of $8,706,638 for Pre-97 and $70,370 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CEC is in compliance with the applicable rules for the rate period.

1998

1. PTF Transmission Plant and the PTF Transmission Allocation Factor are in partial compliance. CEC included $58,571,665 for PTF investment in the calculation of their revenue requirement. Their workpapers show the PTF amount to be only $59,596,099. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission Accumulated Depreciation is out of compliance with Section II.A.1.(d), NEPOOL Tariff, Attachment F. For Transmission Accumulated Depreciation, CEC showed $35,558,320. The FF#1, page 219, line 23c shows $35,526,023. For General Accumulated Depreciation, CEC showed $11,458,685. The FF#1, page 219, line 25c shows $11,448,277. Subsequently, CEC submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of CEC, a revenue requirement of $9,028,867 for Pre-97 and $509,821 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, CEC is out of compliance. Subsequently, CES submitted an updated revenue requirement of $8,637,101 for Pre-97 and $377,676 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CEC is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Commonwealth Edison Company has no comment at this time regarding the audit results as reported herein. However, Commonwealth Edison Company expressly reserves its right to submit written comments and to otherwise participate in any proceeding at the Federal Energy Regulatory Commission regarding this audit report.

Auditor's Response:
No response to the TO comment.

ii. Canal Electric Company

a. PTF and Non-PTF Findings

Canal Electric provided an adequate system diagram that was color-coded to separately identify the PTF and non-PTF lines for the Canal Switchyard. A detailed substation one-line diagram was also provided for the Canal Substation. Similar information for Canal Electric's ownership interest in the Seabrook Station Switchyard was furnished by Northeast Utilities (NU). The one-line diagrams contained adequate detail to provide a basis for assessing the division of station equipment between PTF and non-PTF facilities. The focus of the remainder of this section is the Canal Switchyard, and a detailed review of the Seabrook Station cost allocations which were reviewed in conjunction with the NU's data submittal.

Although, minor items were noted that potentially could be shifted between the cost categories, these items were relatively insignificant and the Auditors find that the costs reported for Canal for 1996 are reasonable. Upon review of the 1997 cost data, the Auditors identified 26 items, totaling $244,481, that were reported as common and one item reported as non-PTF, amounting to $100,990, that should be assigned as PTF. These changes increased the resulting PTF allocation by $275,324, or 6.88% from $3,728,145 to $4,003,468.

Based upon the above exceptions, the Auditor finds the originally filed PTF plant by Canal for 1996, 1997 and 1998 was in partial compliance. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Payroll Taxes are in partial compliance with Section II.E., NEPOOL Tariff, Attachment F. CES included $23,383 of environmental tax for Canal that should not be included. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant as originally filed is in partial compliance. See Section A above for detailed explanation of the finding. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

3. PTF Transmission Allocation Factor is out of compliance with Section I.A.2., NEPOOL Tariff, Attachment F. Canal included $8,268,869 for PTF investment in the calculation of their revenue requirement. Their workpapers show the PTF amount to be $4,276,793. The total transmission plant in both documents are shown to be the same ($9,588,795), excluding HQ capital leases. Making this correction reduces

the PTF Transmission Allocation Factor from 86.23% to 44.60%. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of Canal, a revenue requirement of $715,840 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, Canal is out of compliance. Subsequently, CES submitted an updated revenue requirement of $351,265 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, Canal is in compliance with the applicable rules for the rate period.

1997

1. PTF Transmission Plant as filed is in partial compliance. See Section A above for detailed explanation of the finding. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Allocation Factor is out of compliance with Section I.A.2., NEPOOL Tariff, Attachment F. Canal included $7,302,689 for PTF investment in the calculation of their revenue requirement. Their workpapers show the PTF amount to be $5,583,749. The total transmission plant in both documents are shown to be the same ($9,794,307), excluding HQ capital leases. Making this correction reduces the PTF Transmission Allocation Factor from 74.56% to 57.01%.

Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of Canal, a revenue requirement of $640,571 for Pre-97 and $9,324 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, Canal is out of compliance. Subsequently, CES submitted an updated revenue requirement of $482,353 for Pre-97 and $5,575 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, Canal is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is in partial compliance with the Interpretive Guidance Document and Section II.A.2., NEPOOL Tariff, Attachment F. Canal showed no debt and all equity in 1998. The formula presently does not address this issue.

   In Canal's response on February 28, 2001, Canal stated that this unusual situation resulted from Canal's sale of its generation and PTF facilities on 12/30/98 and attendant defeasance of all outstanding long-term debt. Since the long-term debt was outstanding for only one day short of a year, and was outstanding for the entire time that Canal held PTF facilities, the debt did support Canal's 1998 PTF investment. Canal proposes that the

1997 cost of long-term debt of 9.58% be used as a proxy for the 1998 cost of debt. Canal further proposes to impute a 50/50 debt/equity ratio for the sole purpose of calculating the 1998 overall Rate of Return ("ROR"). This will result in an overall ROR of 10.17% instead of 10.75%. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission Administrative and General, Regulatory Commission Expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. Canal used $367,604. The correct amount is $336,348 per workpapers provided by Canal. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

3. PTF Transmission Plant is in partial compliance. See Section A above for detailed explanation of the finding. Subsequently, CES submitted updated information that, in the Auditor's opinion, is in compliance.

4. The PTF Transmission Allocation Factor is out of compliance with Section I.A.2., NEPOOL Tariff, Attachment F. Canal included $3,016,774 for PTF investment in the calculation of their revenue requirement. The workpapers show the PTF amount to be only $1,660,700. The total transmission plant in both documents are shown to be the same ($3,092,389), excluding HQ capital leases. Making this correction reduces

the PTF Transmission Allocation Factor from 97.55% to 53.70%. Subsequently, Canal submitted updated information that, in the Auditor's opinion, is in compliance.

CES filed, on behalf of Canal, a revenue requirement of $665,909 for Pre-97 and $17,545 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, Canal is out of compliance. Subsequently, CES submitted an updated revenue requirement of $337,148 for Pre-97 and $9,303 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, Canal is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Canal Electric Company has no comment at this time regarding the audit results as reported herein. However, Canal Electric Company expressly reserves its right to submit written comments and to otherwise participate in any proceeding at the Federal Energy Regulatory Commission regarding this audit report.

Auditor's Response:
No response to the TO comment.

iii. Cambridge Electric Light Company

a. PTF and Non-PTF Findings

No PTF plant was reported for 1996, 1997 and 1998.

b. RNS Template Input Findings

None.

CES filed, on behalf of Cambridge, Support Payments of $3,813,530, $2,773,365 and $2,736,789 for 1996, 1997 and 1998, respectively. The filed Support Payments, in the Auditor's opinion, are in compliance.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Cambridge Electric Company has no comment at this time regarding the audit results as reported herein. However, Cambridge Electric Company expressly reserves its right to submit written comments and to otherwise participate in any proceeding at the Federal Energy Regulatory Commission regarding this audit report.

Auditor's Response:
No response to the TO comment.

A.6 Connecticut Municipal Electric Energy Coop (CMEEC)

a. PTF and Non-PTF Findings

CMEEC only had pool transmission facilities beginning in 1998. Therefore, only 1998 PTF plant in service has been reviewed for purposes of this audit. For the years 1996 and 1997, CMEEC incurred Support Payments only.

i. Wallingford:

North Wallingford and Colony

The initial data request asked for all workpapers supporting CMEEC's revenue requirement, including all cost data and supporting documentation. CMEEC provided copies of some information in support of their revenue requirement and later CMEEC provided additional other information in response to the Auditor's findings. CMEEC provided information only for items that CMEEC disputed. CMEEC provided additional information requested by the Auditor.

Wallingford filed cost data for two substations, North Wallingford and Colony. The transmission costs for these two substations are not included in Wallingford's transmission FERC plant accounts. Wallingford will revise its plant accounts in the future to effectuate this change from distribution to transmission.

The Auditor reviewed CMEEC's supporting documents regarding the allocation of certain cost items for North Wallingford and Colony. The Auditor concluded that the items referred to by CMEEC in their correspondence were inappropriately assigned.

The data filed by Wallingford was not assigned between PTF and non-PTF as per Attachment F. Wallingford calculated $1,564,821 of PTF plant and a total transmission plant of $3,014,464. The Auditor verified $898,566 and $2,680,133, respectively.

In addition, land (Account 350) in the amount of $29,232 was not allocated between transmission right-of-ways (ROW) and/or substations. The ROW plant was not further divided between PTF and non-PTF per the rules.

Based upon these exceptions, the Auditor finds the CMEEC PTF cost assignment is out of compliance for 1998. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

ii. Groton:

Buddington Station

The backup information for Buddington station additions in the amount of $2,131,939 was not provided in functional detail. The detail provided did not have enough description to make a PTF determination. The Auditor suggested CMEEC refunctionalize the 1984 balance sheet plant to follow the PTF rules and permit a consistent comparison in future years. Although additional information was provided, the Auditor's review of that information did not change its prior conclusion. Transformer pad costs and the station service transformer costs were adjusted by CMEEC after discussion with the Auditor. The Auditor recommended using the number of terminals as specified in the PTF Rules, Section B, Paragraph 8 when allocating the amounts in question. Based upon this exception, the Auditor finds the CMEEC PTF cost assignment is out of compliance for 1998. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

B. RNS Template Input Findings

i. Wallingford:

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. Changes in PTF plant as reported will affect accumulated depreciation and depreciation expense calculations. Therefore, accumulated depreciation and depreciation expenses are in partial compliance. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Prepayments are in partial compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. CMEEC included $0 in their revenue requirement even though page 210, line 14 of the DPUC Annual Report shows the amount to be $898. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. CMEEC calculated property taxes by multiplying the Mill Rate times Net Investment Rate Base. This is incorrect. CMEEC should multiply Gross Plant times the Mill Rate times the PAF and then times the PTF Factor. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

CMEEC filed a revenue requirement for Wallingford of $381,040 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, CMEEC is out of compliance. Subsequently, CMEEC submitted an updated revenue requirement of $81,689 for Pre-97 and $0 for Post 96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CMEEC is in compliance with the applicable rules for the rate period.

ii. Groton:

1. PTF plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

2. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. CMEEC used 31.95%. However, the correct amount should be 8.0% in accordance with the Interpretive Guidance Document. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

3. General Plant is out of compliance with Section II.A.1.(b), NEPOOL Tariff, Attachment F. CMEEC filed $0. The DPUC Annual Report, page 502,

line 13, reports this to be $3,342,527. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission and General Accumulated Depreciation is out of compliance with Section II.A.1.(d), NEPOOL Tariff, Attachment F. No workpapers were provided deriving the amount shown of $5,448,004. The Auditor needs workpapers showing the functionalization of the amount shown in the DPUC Annual Report on page 508 of $19,960,214 for Transmission Accumulated Depreciation and $0 for General Accumulated Depreciation. Since PTF has changed, Auditor believes the accumulated depreciation and depreciation expense should have a corresponding change. CMEEC made no such change. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. CMEEC filed zero. The DPUC Annual Report, page 209 showed this to be $674,326. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

6. Depreciation Expense is out of compliance with Section II.B., NEPOOL Tariff, Attachment F. No workpapers were provided to show the derivation of $306,167 for transmission and $0 for general. Since PTF has

changes, Auditor believes that the accumulated depreciation and depreciation expense should have a corresponding change. CMEEC made no such change. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

7. Transmission O&M is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F. CMEEC did not exclude Station Expenses (Acct. 562) $9,818. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

8. Transmission A&G expense is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. CMEEC did not include any amounts for A&G expense although the 1998 Annual Report shows A&G expenses. A&G expense should be $1,940,370, less the FERC Account 924 amount of $69,635. CMEEC did not provide workpapers for FERC Account 930 to determine if there are any transmission related expenses in that account. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

9. Payroll Tax Expenses are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. CMEEC did not include $137,621 of FICA tax incurred. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

10. Transmission Wages and Salaries Allocation Factor is in partial compliance with Section I.A.1., NEPOOL Tariff, Attachment F. CMEEC used $337,126 from DPUC Annual Report, page 520. CMEEC should have used $753,842 from DPUC Annual Report, page 507. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

11. Plant Allocation Factor is in partial compliance with Section I.A.3., NEPOOL Tariff, Attachment F. CMEEC did not include any general plant in their calculations. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

12. Property taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. CMEEC calculated property taxes by multiplying the Mill Rate times Net Investment Rate Base. This is incorrect. CMEEC should multiply Gross Plant times the Mill Rate times the PAF and then times the PTF Factor. Subsequently, CMEEC submitted updated information that, in the Auditor's opinion, is in compliance.

CMEEC filed a revenue requirement for Groton of $89,459 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, CMEEC is out of compliance. Subsequently, CMEEC submitted an updated revenue requirement of $140,982 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CMEEC is in compliance with the applicable rules for the rate period.

iii. Bozrah:

CMEEC filed, on behalf of Bozrah, a RNS Revenue Requirement of $1,850 for 1998. Insufficient data were received for Auditor to review and verify. Therefore, Bozrah's revenue requirement is out of compliance and was set to $0.

iv. Norwich:

CMEEC filed, on behalf of Norwich, a RNS Revenue Requirement of $135,412 for 1998. Insufficient data were received for Auditor to review and verify. Therefore, Norwich's revenue requirement is out of compliance and was set to $0.

Support Payments

In the original filing for 1998, CMEEC included $174,779 for Support Payments. The filed Support Payments, in the Auditor's opinion, are in compliance.

C. Participant's Comments and Auditor's Response

Participant's Comments:
The Connecticut Municipal Electric Energy Cooperative ("CMEEC") does not believe that either CMEEC or the other municipal transmission owners (MTOs) were originally a party to discussions surrounding the establishment of the PTF Rules. As a result, not all Rules as written can be directly applied to the MTO's. CMEEC believes this made for a difficult situation for both CMEEC and Rhema Services, Inc. ("RSI") in coming up with information in the required format and in the detail deemed sufficient under RSI's interpretation of the PTF Rules. Consequently, CMEEC conceded to RSI's recommendations to reach an "in compliance" status for purposes of the Audit.

CMEEC reserves its right to comment on or otherwise address any and all aspects of the final NEPOOL RNS Audit Report, and any responses filed or position taken by any other NEPOOL transmission owner, market participant or other intervener in any dispute before the Federal Energy Regulatory Commission or in any other appropriate forum concerning the RNS Audit Report, and further reserves its right to pursue such remedies as it deems appropriate.

Auditor's Response:
No response to the TO comment.

A.7 Eastern Utilities Associates (EUA)

a. PTF and Non-PTF Findings

EUA provided system and substation one-line diagrams to facilitate an assessment of their PTF eligible facilities. Data was presented separately by substation for each of the four operating subsidiary companies, namely Blackstone Valley Electric Company (BVE), Eastern Edison Company (EEC), Montaup Electric Company (MEC) and Newport Electric Corporation (NEC).

EHV transmission lines remained at 68.5 miles for all three years, and lower voltage transmission line mileage increased from the 1996 and 1997 level of 229.4 miles to 245.8 miles for 1998. Lines in the PTF catalog were checked against the system map, and after resolution of some initial questions, the Auditor found the maps and the catalog to be consistent. In many instances, the accounting data employed a different naming convention than the one used in the PTF catalog and the accounting reports could not be readily reconciled to the PTF catalog. The financial detail provided (both mileage data and cost data) were checked against the mileage reported in the PTF Catalog. Except for a minor difference of 1.7 miles, the reported mileage in the two reports matched.

A sample of substations was reviewed for each of the four operating subsidiaries. The reported cost information was provided on a more consolidated basis. Had greater detail been available, it is probable that the resulting allocations could differ. The methodology employed was easy to follow, however in a number of substations, the Auditor did not concur with the resulting allocations and amounts allocated to PTF. Areas where the Auditor take exception to the results presented by EUA for the four operating subsidiaries are listed below:

i. Blackstone Valley Electric Company (BVE)

The **Riverside Substation** costs contain five breakers with four cost entries totaling $45,554. Two of the breakers are non-PTF. The Auditor suggests that two-fifths of the total cost be assigned to non-PTF, or $18,222. EUA assigned only $9,899 based on two-thirds the cost of one of the breaker entries that reportedly represented the cost of three breakers. EUA'S PTF investment submission had the total Riverside Substation investment of $724,496 defined as PTF. However, 2 of the 4 circuit breaker installations serve a non-PTF function. Based on the Auditor's examination, EUA's final audited Riverside PTF investment was changed to $172,140. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

For the **Pawtucket Substation**, the Auditor questions the assignment of all five breakers to PTF based on the 1996 rules. The station consists of three bus sections that are separated by two bus-tie breakers. The remaining three breakers provide line terminal switching for the three transmission lines. The

Auditor's reading of the rules for 1996 would preclude inclusion of additional switching facilities that would not otherwise exist except for the non-PTF function. In the absence of the non-PTF facilities, the two bus-tie breakers would be redundant with the line terminal breakers and serve a non-PTF function. The result of the assignment of two additional breakers and associated disconnect switches to non-PTF yields an adjusted PTF cost of $296,683 versus the $529,010 amount submitted by EUA. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

Using the rules that apply to 1996, the **Staples and Valley Substation** costs are not PTF eligible in 1996. Accordingly, the Auditor finds that the $24,995 and $179,604 PTF amounts reported for the Staples and Valley Substations, respectively, should be non-PTF in 1996. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

ii. Eastern Edison Company (EEC)

The one-line diagram for **Dupont Substation** does not depict the same facilities as reported in the cost summary sheet, nor reflect facilities shown for Dupont on the system diagram. Using the system one-line diagram, Dupont Substation terminates two PTF lines, namely line G-18 from Bridgewater and line C-2 from Auburn Street. As a two-line substation serving distribution load, it would be considered a non-PTF facility in 1996. Accordingly, the

Auditor finds the $647,655 shown to be PTF for 1996 should be totally reclassified as a non-PTF investment, resulting in a 1996 PTF investment of $0 for the Dupont Substation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

iii. Montaup Electric Company (MEC)

The originally filed PTF plant in service for the jointly owned substation facilities at **Seabrook Station and Canal #2 Station** were out of compliance with the PTF rules because the owners, NU and CES, respectively, had not provided workpapers to substantiate the PTF allocations. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

In the 1998 data for the **Somerset Substation,** the calculation is unclear. It appears that the final page (page 9 of 30) was omitted from the supporting documentation provided. From the final results carried forward to the summary page, the Auditor was able to conclude that the transformers were inappropriately considered as PTF investment. EUA changed the total substation PTF investment from $3,686,047 to $2,500,802. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

The one-line diagram for **Bell Rock** indicates two transformers that appear beyond the ownership line. This implies the transformers are owned by

Commonwealth Electric. The cost data contains entries for two 115 kV circuit switches ($26,300), which appear to relate to these two transformers. Also, the data contains an entry for three 10,000 kVA Maloney Transformers ($145,206), which also seem to relate to these transformers. The Auditor takes exception to the reporting of the full station cost as PTF. The Auditor's analysis supports a PTF assignment of $146,771 versus the $635,986 claimed by EUA. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

From the one line-diagram, **Swansea Substation** is also a simple two PTF line substation serving a distribution function. As such, it would not be considered a PTF eligible facility in 1996. Accordingly, the Auditor finds the $452,846 amount shown to be non-PTF for 1996. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

iv. Newport Electric Corporation (NEC)

From the one-line diagram provided for **Canonicus Switching Station**, three switches are shown. As understood, switch M13114 is operated normally open, and as such would not meet the PTF Rule Section B.2. This rule requires that the facility, to be considered a PTF facility, needs to be one that "carries any power flow at 69 kV or above through parallel paths with the interconnected network under normal operation." The Auditor analysis supports a PTF assignment of $120,120 versus the $180,180 as claimed by

EUA. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

The 1996 station one-line diagram and cost data for **Dexter Substation** were reviewed. Although one breaker and two switches would be assigned to non-PTF under 1996 rules, the cost data reflects only an assignment of one breaker and one switch. With the appropriate adjustments, the Auditor computes the Dexter Substation PTF for 1996 to be $2,022,561. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

The 1996 station one-line diagram for **Jepson Substation** is marked to identify one-half of breaker numbers 3765 and 3764 as PTF facilities. The Auditor interprets the rules in effect to also provide that one-half of breaker numbers 3766 and 3769 would also be PTF eligible. With this adjustment, the Auditor computes the Jepson Substation PTF for 1996 to be $294,498. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

Based upon the above noted findings, in the Auditor's opinion, the PTF plant as originally filed is out of compliance for 1996, 1997 and 1998. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

i. Blackstone Valley Electric Company (BVE)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. EUA provided supporting documents used in the original revenue requirement filing. EUA acknowledged for BVE, they used beginning of year balances and a ROE of 11.43% instead of the 11.22% shown in the Settlement Agreement and per Attachment F rules. EUA provided revised workpapers calculating their weighted cost of capital. The revised workpapers used a cost of long-term debt which deviated from what was filed at the FERC in EUA's original filing. The revised workpapers computed a cost of long-term debt of 9.32%. The method filed with FERC used the cost number from page 218 of the FF#1 of 9.35%. Per the Interpretative Guidance Document, the Auditor is to verify the methodology as approved by FERC. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the findings. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $872,689 which is the

total materials and supplies. As defined in Attachment F, Section I.B. *...Transmission Plant Materials and Supplies shall equal Transmission Provider's balance as assigned to transmission, as recorded in* *<u>FERC Account No. 154.</u>* Account 154 as shown in FF#1, page 227, line 11 is $753,773. Furthermore, EUA allocated the M&S by the transmission wage and salaries allocation factor. Per the Interpretative Guidance Document *...if allocated data is utilized, the Plant Allocation Factor (as defined in Section I.A.3) is a reasonable basis for allocating materials and supplies and may properly be used to make the allocation.* Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. EUA in their calculation of Affiliate Company Wages and Salaries included all the FERC 900 accounts. Only FERC Accounts 920-935 are to be included in the calculation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of BVE, a revenue requirement of $1,200,623 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, BVE is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $2,426,621 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, BVE is in compliance with the applicable rules for this rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. EUA used 11.43% for the cost of capital on ROE, per Attachment F rules the ROE should be 11.22%. See detailed explanation in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $759,282 which is the total materials and supplies. As explained in 1996 3. above, the amount EUA should use is only FERC Account 154 ($707,326) as shown on line 11 of page 227 of the FERC Form 1. Also, M&S should be allocated using the PAF not the TWSAF. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. See explanation in 1996 4. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of BVE, a revenue requirement of $1,294,724 for Pre-97 and $25,663 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, BVE is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $2,642,501 for Pre-97 and $38,439 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, BVE is in compliance with the applicable rules for this rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. See detailed explanation in 1996 1. above. EUA reflected the ROE change, per Attachment F Rules, to 10.65% for the 1998 cost year. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies is out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $857,075 which is the total materials and supplies. As explained in 1996 3. above, EUA should use FERC Account 154 ($821,344) as shown on line 11 of page 227 of the FF#1. Also, M&S should be allocated using the PAF not the TWSAF. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. EUA in their calculation of Affiliate Company Wages and Salaries included all the FERC 900 accounts. Only FERC Accounts 920-935 are to be included in the calculation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of BVE, a revenue requirement of $1,056,158 for Pre-97 and $30,474 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, BVE is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $1,036,150 for Pre-97 and $33,900 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, BVE is in compliance with the applicable rules for this rate period.

ii. Eastern Edison Company (EEC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. EUA provided supporting documents used in the original revenue requirement filing. EUA acknowledged for EEC, they used beginning of year balances and a ROE of 11.50% instead of the 11.22% shown in the Settlement Agreement and per Attachment F rules. EUA provided revised workpapers calculating their weighted cost of capital. The revised workpapers computed a cost of long-term debt of 6.92%. The method filed at FERC used the cost number from page 218 of the FF#1 of 7.62%. Per the Interpretative Guidance Document, the Auditor is to verify the methodology as approved by FERC. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the findings. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $1,743,804 which is the total materials and supplies. As explained in BVE 1996 3. above, the amount should have used is $1,572,922 as shown in FF#1, page 227, line

11, FERC Account 154. Also, M&S should be allocated using the PAF not the TWSAF. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. Based on the Auditor's review of the workpapers provided, EUA incorrectly included all FERC 900 accounts for A&G expenses. Only FERC Accounts 920-935 should be included in the A&G calculation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of EEC, a revenue requirement of $256,891 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, EEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $342,843 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, EEC is in compliance with the applicable rules for this rate period.

1997

1. Cost of Capital is out of compliance per Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. Above. Subsequently, EUA

submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the findings. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies is out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $1,726,331 which is the total materials and supplies. As explained in BVE 1996 3. above, the amount EUA should have used is $1,672,682 as shown in FF#1, page 227, line 11, FERC Account 154. Also, M&S should be allocated using the PAF not the TWSAF. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F, as explained in 1996 4. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of EEC, a revenue requirement of $283,416 for Pre-97 and $13,634 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, EEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $439,625 for Pre-97 and $78,739 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, EEC is in compliance with the applicable rules for this rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Materials & Supplies is out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. EUA used $1,952,793 which is the total materials and supplies. As explained in 1996 3. above, the amount EUA should have used is $1,853,657 as shown on page 227, line 11, FERC Account 154 (FERC Form 1). Also, M&S should be allocated using the PAF not the TWSAF. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F, as explained in 1996 4. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of EEC, a revenue requirement of $529,206 for Pre-97 and $140,716 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, EEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $492,078 for Pre-97 and $298,892 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, EEC is in compliance with the applicable rules for this rate period.

iii. Montaup Electric Company (MEC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. EUA provided supporting documents used in the original revenue requirement filing. EUA acknowledged for MEC, they used beginning year balances and a ROE of 11.10% instead of the 11.22% shown in the Settlement Agreement and per Attachment F rules. EUA provided revised workpapers calculating their weighted cost of capital. The revised workpapers computed a cost of long-term debt of 7.25%. The method filed at the FERC used the cost number from page 218 of the

FF#1 of 7.87%. Per the Interpretative Guidance Document, the Auditor is to follow the methodology as approved by FERC. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Rent from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. The total amount included in Account 454 was $1,395,284 (see line 19 of page 300 of FF#1), but only $327,306 was credited to transmission as Support Revenue. EUA provided documentation which shows the correct amount should be $393,620. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of MEC, a revenue requirement of $7,726,475 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, MEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $7,940,456 with supporting documentation that incorporates the above findings. Based upon the new information, in the

Auditor's opinion, MEC is in compliance with the applicable rules for this rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Rent from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. The total amount included in Account 454 was $1,411,370 (see line 19 of page 300 of FF#1), but only $306,693 was credited to transmission as Support Revenue. EUA provided documentation which shows the correct amount should be $375,014. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of MEC, a revenue requirement of $7,893,987 for Pre-97 and $18,953 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, MEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $8,414,810 for Pre-97 and $19,169 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, MEC is in compliance with the applicable rules for this rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Loss on Reacquired Debt is out of compliance with Section II.A.1.(f), NEPOOL Tariff, Attachment F. The FF#1, page 111, line 65 (d) shows this to be $9,776,250. EUA in their revenue requirement filing showed $0. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Rent from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. The total amount included in FERC Account 454 was $1,444,019 (see line 19 of page 300 of FF#1), but only $287,385 was credited to transmission as Support Revenue. EUA provided documentation which shows the correct amount should be $346,763. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of MEC, a revenue requirement of $8,300,802 for Pre-97 and $67,151 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, MEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $7,907,974 for Pre-97 and $50,556 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, MEC is in compliance with the applicable rules for this rate period.

iv. Newport Electric Corporation (NEC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. EUA provided supporting documents used in the original revenue requirement filing. EUA acknowledged for NEC, they used beginning of year balances and a ROE of 11.40% instead of the 11.22% shown in the Settlement Agreement and per Attachment F rules. EUA

provided revised workpapers calculating their weighted cost of capital. The revised workpapers computed a cost of long-term debt of 7.38%. The method filed at FERC used the cost number from page 218 of the FERC Form 1 of 7.69%. Per the Interpretative Guidance Document, the Auditor is to follow the methodology as approved by FERC. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. Based on the Auditor's review of the workpapers provided, EUA incorrectly included all the 900 FERC accounts for A&G expenses. Only Accounts 920-935 should be included in the A&G calculation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of NEC, a revenue requirement of $513,498 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, NEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $871,954 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, NEC is in compliance with the applicable rules for this rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1, NEPOOL Tariff, Attachment F as explained in 1996 3. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of NEC, a revenue requirement of $628,515 for Pre-97 and $4,192 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, NEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $1,228,085 for Pre-97 and

$4,780 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, NEC is in compliance with the applicable rules for this rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

3. PTF Transmission Plant Allocation Factor is out of compliance with Section I.A.2., NEPOOL Tariff, Attachment F. EUA used $7,053,729 in the development of the PTF Transmission Plant Allocation Factor. The FF#1, page 207, line 53, shows total transmission plant to be $7,890,070. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. EUA in their calculation

of Affiliate Company Wages and Salaries, included all the FERC 900 accounts. Only A&G accounts (920-935) are to be included in the calculation. Subsequently, EUA submitted updated information that, in the Auditor's opinion, is in compliance.

EUA filed, on behalf of NEC, a revenue requirement of $978,722 for Pre-97 and $3,897 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, NEC is out of compliance. Subsequently, EUA submitted an updated revenue requirement of $956,726 for Pre-97 and $4,330 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, NEC is in compliance with the applicable rules for this rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
National Grid USA (National Grid) has no additional comments at this time to the RNS Audit Report. However, National Grid reserves its rights to object to any of the conclusions presented by Rhema Services, Incorporated ("RSI") in their audit report of the revenue requirements calculations for the NEPOOL Regional Network Service (RNS) rates in effect June 1, 1997 through May 31, 2000 after the required audit informational filing is made with the Federal Energy Regulatory Commission (FERC). RSI performed the audit on behalf of ISO New England Inc. National Grid also reserves its rights to comment on any responses filed or positions taken by any entity in any dispute that arises after the audit report informational filing is made with the FERC. Particularly, National Grid reserves its rights related to any comments or responses to the Audit's findings on New England Power's 1998 Divestiture Adjustment.

National Grid is providing these comments on behalf of its subsidiaries, New England Power Company and The Narragansett Electric Company (Narragansett Electric), and on behalf of the former Eastern Utilities Associates (EUA) and its former subsidiaries, Blackstone Valley Electric Company, Eastern Edison Company, Montaup Electric Company, and the Newport Electric Corporation.

Auditor's Response:
No response to the TO comment.

A.8 Fitchburg Gas & Electric Light Company (FG&E)

a. PTF and Non-PTF Findings

FG&E provided adequate one-line diagrams to facilitate an assessment of their PTF eligible facilities.

FG&E's total transmission plant by FERC accounts did not tie to the FF#1 numbers. FG&E stated that it had transferred $4,268,500 from transmission to distribution accounts. The Auditor did not receive any workpapers reconciling the FF#1 transmission accounts with the filed figures. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

In 1996 and 1997, the Flag Pond 115/69 kV Substation, the two 69 kV lines between Flag Pond and Summer Substation are considered to contain PTF eligible facilities. Under 1996 rules, the auditor finds that the Flag Pond 115 kV six breaker ring bus, two 115/69 kV transformers and 2/3rd of the 69 kV ring bus would be PTF eligible. The two 69 kV lines are included in the PTF Catalog for 1996, thus they are considered to be PTF eligible. At Summer Substation, two of six line terminals are PTF eligible.

Under 1997 rules, the Auditor finds that the Flag Pond 115 kV six breaker ring bus, two 115/69 kV transformers and all of the 69 kV ring bus would be PTF eligible. The two 69 kV lines are included in the PTF Catalog for 1997, thus they are considered to be PTF eligible. At Summer Substation, two of six line terminals plus the bus-tie breaker are PTF eligible.

In 1998, the two 69 kV lines are omitted from the PTF catalog, so only the Flag Pond 115 kV ring bus is PTF eligible in 1998. FG&E explained that their generation, which qualified the two 69 kV lines as PTF, was sold at the end of 1998. FG&E agreed that for 1999 the two lines were no longer PTF eligible, but contends that they should have been PTF eligible in 1998. Because the Auditor was unable to find the two 69 kV lines in the 1999 PTF Catalog for 1998, the Auditor found these lines ineligible for 1998.

The substation diagram shows a 115/69 kV, two-winding 24/27 MVA delta-wye, transformer. The cost data contains an entry for a used 24/40 MVA Magnex transformer at a cost of $200,032. In addition, an entry is included in the amount of $237,602 for the construction of 115 kV facilities and the connection of a spare transformer in place of the failed #1 autotransformer. Although the diagram description is not consistent with the description in the cost data, it is believed that these relate to the same facility. This equipment remains as a normally open spare transformer. Under the rules, a facility must be operated to carry network flows under normal conditions, thus the Auditor finds these costs, totaling $437,634 ($237,602+$200,032) to be non-PTF.

Appendix A

There were a number of instances where interpretation of the descriptive data could have resulted in a modification of the cost assignments among PTF, non-PTF, common and transformers. The Auditor verified the costs accordingly in the following table:

	1996		1997		1998	
PTF Line Cost Validated	$	976,418	$	976,418	$	-
PTF Flagg Pond Substation Validated		3,046,591		3,184,971		1,410,826
PTF Summer Substation Validated		104,947		169,093		-
Total Validated	$	4,127,956	$	4,330,482	$	1,410,826
Total PTF Per FG&E	$	4,774,640	$	4,773,765	$	1,444,337
Difference	$	646,684	$	443,283	$	33,511
Difference as a % of Validated PTF		15.7%		10.2%		2.4%

The above differences are considered beyond acceptable limits for 1996 and 1997, and accordingly, the Auditor finds FG&E to be out of compliance with their PTF cost submittal and supporting data requirement for those two years. Differences are minor for year 1998, and accordingly, the Auditor finds FG&E to be in compliance with their PTF cost submittal and supporting data requirement for 1998. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Transmission PTF is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

2. Transmission Plant Held for Future Use (PHFU) is out of compliance with Section II.A.1.(c), NEPOOL Tariff, Attachment F. FG&E used an allocation of $26,750 (FF#1, page 214) times the TWSAF times the PTF which is not per the Attachment F rules. In addition, FG&E did not provide detailed information for the Auditor to determine what was PTF and non-PTF related. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

3. Other Regulatory Assets/Liability is out of compliance with Section I.B., NEPOOL Tariff, Attachment F. Per Attachment F Rules, FAS 109 *...shall equal the net of the Transmission Provider's FAS 109 balance in FERC <u>Account 182.3</u> and any FAS 109 balance as recorded in the Transmission Provider's FERC <u>Account 254</u> (Emphasis added).* The FF#1 for Account 182.3 shows $0 and Account 254 also shows $0. FG&E, in its response, states that the above figures were booked to the wrong accounts. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. General Depreciation Expense is in partial compliance with Section II.B., NEPOOL Tariff, Attachment F. Depreciation Expense for Transmission Plant *shall equal the Transmission Provider's transmission expenses as recorded in <u>FERC Account 403</u> (emphasis added).* FG&E used the sum

of Accounts 403 & 404. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission O&M expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F. In reviewing the workpapers provided by FG&E for FERC Accounts 562 and 567, Account 562 included support payments for Millstone 3 which should be excluded from Transmission O&M. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

6. Regulatory Commission Expenses are in partial compliance with Section II.H., NEPOOL Tariff, Attachment F. The FF#1 shows total Regulatory Commission Expenses to be $312,248. FG&E excluded this amount, and then added back $80,366 to the revenue requirement calculation. The Auditor finds that the correct amount to be added back is $0 because 1) there are no FERC assessments shown in the FF#1 and 2) there are no Account 928 expenses that are shown to be transmission-related. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

7. Payroll Tax Expense is in partial compliance with Section II.F., NEPOOL Tariff Attachment F. FG&E used a total of $196,749. The FF#1 amounts add to $323,907 (Federal Unemployment $6,568, FICA $419,652,

Medicare $37,805, Payroll Taxes Capitalized <$142,444>). FG&E responded with the supporting workpapers reconciling the amount used in the revenue requirement filing. The only discrepancy was in the MA Health Insurance in which they used $1,937, which is the combined total of gas and electric. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

FG&E filed a revenue requirement of $602,400 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, FG&E is out of compliance. Subsequently, FG&E submitted an updated revenue requirement of $516,583 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, FG&E is in compliance with the applicable rules for the rate period.

1997

1. Transmission PTF is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, FG&E submitted updated information that, in Auditor's opinion, is in compliance.

2. Transmission Plant Held for Future Use is out of compliance with Section II.A.1.(c), NEPOOL Tariff, Attachment F as explained in 1996 2. above. Subsequently, FG&E submitted updated information that, in Auditor's opinion, is in compliance.

3. Other Regulatory Assets/Liabilities is out of compliance with Section I.B., NEPOOL Tariff, Attachment F as explained in 1996 3. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. General Depreciation Expense is out of compliance with Section II.B., NEPOOL Tariff, Attachment F as explained in 1996 4. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission O&M expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

6. Regulatory Commission Expenses are in partial compliance with Section II.H., NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

FG&E filed a revenue requirement of $613,183 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the

Auditor's opinion, FG&E is out of compliance. Subsequently, FG&E submitted an updated revenue requirement of $553,651 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, FG&E is in compliance with the applicable rules for the rate period.

1998

1. Transmission Plant Held for Future Use is out of compliance with Section II.A.1.(c), NEPOOL Tariff, Attachment F as explained in 1996 2. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

2. Other Regulatory Assets/Liabilities is out of compliance with Section I.B., NEPOOL Tariff, Attachment F as explained in 1996 3. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission O&M expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. Regulatory Commission Expenses are in partial compliance with Section II.H., NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, FG&E submitted updated information that, in the Auditor's opinion, is in compliance.

FG&E filed a revenue requirement of $163,056 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, FG&E is out of compliance. Subsequently, FG&E submitted an updated revenue requirement of $158,429 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, FG&E is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Fitchburg Gas and Electric Light Company ("FG&E") submits the following comments regarding the NEPOOL Regional Network Service Audit Report ("Audit Report") for inclusion in the Audit Report and informational filing.

In Section a. PTF and Non-PTF Findings, the audit report notes that plant investment amounting to $437,634 in 1996 and 1997, associated with two spare transformers supporting FG&E's PTF System were Non-PTF. FG&E submits that the rules associated with the ability of lines to carry network flows, which appears to be the basis for such a determination, do not properly pertain to spare equipment and the equipment in question[1] was properly classified by FG&E as PTF in 1996 and 1997.

According to the Audit Report, under the rules, a facility must be operated to carry network flows under normal conditions in order to qualify as PTF. The Audit Report

[1] The equipment is referenced in the audit as a purchased used Auto Transformer 24/40 MVA Magntek at a cost of $200,032 and constructed 115 kV facilities and connect spare transformer in place of failed #1 auto transformer at a cost of $237,602 (the "Flagg Pond Spare Transformers" or "Equipment").

further states that, since the Equipment remains as a normally open spare, these costs, totaling $437,634 are non-PTF.

The NEPOOL Reliability Committee was called to discuss and respond to a number of questions directed to it by the NEPOOL Transmission Settlement Subcommittee arising out of the audit process. The treatment of spare equipment was specifically identified as an issue, as rules for determining PTF plant investment are silent on the issue of spare equipment.

On February 13, 2001 the Reliability Committee responded that it could not resolve the issue of whether spare equipment is PTF. The Reliability Committee's 5 to 4 vote did not reach the two thirds majority required for approval per Section 6.10 of the Restated NEPOOL Agreement. Since the Reliability Committee provided no definitive answer to this issue, the Auditors chose to apply what they called "literal interpretation" of the rules.[2] Under the "literal interpretation" they found that a facility must be operated to carry network flows under normal conditions in order to be properly classified as PTF. As noted above, FG&E believes that such interpretation, as applied to the Flagg Pond Spare Transformers is incorrect.

It is correct that, with respect to lines, the NEPOOL Agreement (the "Agreement") at Section 13.1 (1) (c) excludes from PTF lines that are normally operated open. However, Section 13.1 (iv) of the Agreement also provides that, for lines that are listed in the schedule (the PTF Catalog), "related breakers, transformers and substation facilities which link such lines" will constitute PTF provided the owner is a signatory to the Agreement.

NABS Procedure 12 parallels the NEPOOL Agreement and states that all transmission lines rated at 69 kV and above are PTF except:

a. Those required to serve local load only,
b. Generator leads,
c. Lines that are normally operated open.

NABS Procedure 12 is silent on the treatment of spare equipment.[3]

In accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, transformers, including spare transformers, are capitalized and are considered to be plant in service. In this case, the equipment is recorded to Account 353, Station Equipment, which by definition, includes the cost installed of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits.

[2] See Appendix D.2 of the final RNS Audit Report.
[3] See Appendices C.3 and C.4 of the final RNS Audit Report.

Although the definition of Station Equipment is not explicit with respect to spare equipment, FG&E relies on the definition of Account 368, Transformers, in classifying transformers. The definition of Account 368, Transformers clearly includes spare equipment as plant in service. This account includes the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility, for use in transforming electricity to the voltage at which it is used by the customer, whether actually in service or held in reserve.[4]

Similar to spare transformers, Material and Supplies are plant held in reserve and are needed and available to maintain the PTF facilities in reliable operation. It should be noted that pursuant to Attachment F of the NEPOOL Tariff, Transmission Materials and Supplies ("M&S") are allocated to PTF.[5]

Since as seen, spare equipment can be properly included as plant in service, then the issue becomes whether or not the Equipment was PTF in 1996 and 1997. The Equipment was maintained solely to provide emergency spare capability for the 2 "in-service" Flagg Pond PTF transformers. The Flagg Pond substation was listed as PTF during the relevant period and no one disputes such classification. Because the Equipment was linked to PTF equipment, the two spare Flagg Pond Transformers should be included as PTF plant as well. This treatment would be consistent with the Reliability Committee's answers to Questions 2 and 3 as provided during the February 13, 2001 meeting. As indicated in the Reliability Committee's answers referenced above, when lines are involved, the PTF Catalog is the governing document. If the line associated with the equipment in question is in the PTF Catalog, the equipment is PTF.[6]

Finally, FG&E submits that, if new rules or interpretations are to be developed to clarify PTF allocations going forward, they cannot and should not be applied retroactively where such rules clearly did not exist previously.

The audit report in Section a also indicates that there were a number of instances where interpretation of the descriptive data could have resulted in a modification of the cost assignments among PTF, non-PTF, common and transformers. Except for the assignment of Flagg Pond Spare Transformers to non-PTF as discussed above, FG&E notes that it has accepted the auditors plant assignment for purposes of this audit which specifically includes the years 1996, 1997, and 1998.

The difference between the auditor's computations and FG&E's relates to plant that was categorized as common rather than being assigned directly as either PTF or non-PTF. FG&E explained to the auditors that when it completed its original PTF

[4] It is not appropriate to include the costs of spare transformers in Account 105, Plant Held for Future Use. The definition for Plant Held for Future Use specifically indicates that transformers held in reserve shall not be included as Plant Held for Future Use.

[5] See Appendix C.2 of the final RNS Audit Report.
[6] See Appendix D.1 of the final RNS Audit Report.

allocations, a significant amount of time and effort was devoted to researching work orders and other sources of information to determine whether the facilities were PTF or non-PTF. The results were reflected in FG&E's PTF workpapers. In allocating between PTF and non-PTF, the auditors assigned much more of the facilities to common than FG&E, which was then allocated between PTF and non-PTF based on the PTF ratio. It turned out that the PTF ratio was almost identical between the auditor's and FG&E's analyses, so the end result was not significantly different. However, FG&E's concern is that by accepting the auditor's methodology, the methodology may apply to future years.

FG&E believes that its methodology is more accurate and exact, given the significant amount of time and review devoted to the original cost assignment. In discussing this matter, the auditors informed FG&E that they are working with the descriptions contained in the accounting records and those form the basis of their determinations. Detailed work orders were not reviewed nor were required to be reviewed as part of the audit. FG&E agrees that based on the descriptions alone, a definitive determination of assignment can not be made in many instances. The auditors have recommended that in subsequent years, FG&E should revise the descriptions in the accounting records so that it's clear whether the plant item is PTF or non-PTF. FG&E will take this under advisement.

With respect to Section b., RNS Template Input Findings, except for item 1 in each year which relates to PTF Plant discussed above, FG&E accepts the findings as applied in the revenue requirement reflected in the "per Audit" column of Tables 4, 5 and 6 of the Audit Report.

FG&E reserves its right to comment or otherwise address any and all aspects of the final NEPOOL RNS Audit Report and any responses filed or positions taken by any other NEPOOL transmission owner or market participant in any dispute before the Federal Energy Regulatory Commission or in any other appropriate forum. FG&E reserves the right to supplement its response in any pleadings it might choose to file at the Federal Energy Regulatory Commission.

Auditor's Response:
No response to the TO comment.

A.9 Holyoke Gas & Electric Light Department (HG&E)

a. PTF and Non-PTF Findings

HG&E originally filed a PTF plant of $4,185,374, $4,185,517 and $4,186,247 for 1996, 1997 and 1998, respectively. Subsequently, during this audit, HG&E revised its PTF plant to $5,744,935, $5,745,078 and $5,745,808 for 1996, 1997 and 1998, respectively. Finally, HG&E revised its PTF plant to be $5,463,337, $5,525,651 and $5,526,381 for 1996, 1997 and 1998, respectively.

The Auditor was unable to verify the originally filed PTF plant because HG&E provided inadequate workpapers to support its originally filed PTF plant. HG&E states that it under-estimated the transmission PTF plant in their original filing because it relied on internal engineering estimates that assumed $2 million of transmission costs were non-PTF based. The Auditor was not provided a copy of the engineering estimates relied upon by HG&E and was unable to verify HG&E's original assignments between the transmission and distribution accounts.

Additional workpapers supplied by HG&E supporting their revised assignment of PTF plant do not substantiate HG&E's assignment of PTF and non-PTF plant. The additional plant information supplied by HG&E was not detailed enough to permit the classification of these facilities between PTF, non-PTF and common. Based on discussions with HG&E and a review of HG&E's

workpapers, the Auditor could not ascertain if HG&E transferred costs from distribution to transmission plant or vice versa. In addition, from the information provided, the Auditor was unable to verify HG&E's breakdown of transmission costs between lines and substations. A major portion of HG&E's transmission plant investment was installed as a turnkey/lumped bid package and consequently, HG&E was unable to accurately assign costs.

The Auditor recommends HG&E use Rule 8 to allocate the substation costs included in FERC account #353 between PTF and non-PTF using the number of terminals (2 of 4) excluding the transformer costs. FERC accounts #355 and #356 should be assigned all to PTF. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

3. General Plant Accumulated Depreciation is out of compliance with Section II.A.1.(d), NEPOOL Tariff, Attachment F. The Annual Report shows that Accumulated Depreciation should be $1,467,949 ($4,252,008 - $2,784,059 = $1,467,949). Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. HG&E excluded $1,159,461 shown in the Annual Report for Account 165. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

5. Amortization of Loss on Reacquired Debt is out of compliance with Section II.A.1.(f), NEPOOL Tariff, Attachment F. HG&E excluded $41,459 shown in the Annual Report for Account 428. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

6. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. HG&E employed a methodology that in the Auditor's

opinion is not a generally accepted or traditionally used methodology. HG&E has a payment in lieu of taxes (PILOT) expense in its books. HG&E's PILOT payment as shown in the Annual Report on page 21, line 24 is $400,000. In this case, the Auditor believes the proper calculation should be based upon the booked PILOT payment times the ratio of electric gross plant over total gross plant (gas and electric) times the PAF times the PTF Factor equals the PTF property tax. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

7. Transmission O&M expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F. The Interpretative Guidance Document states ...*HG&E did not have its operations and maintenance expenses directly assigned for transmission. To arrive at the Transmission Operation Maintenance and Expense component, HG&E multiplied the Plant Allocation Factor by all operation and maintenance supervision accounts. HG&E then took that number and multiplied it by the PTF Transmission Plant Allocation Factor. ... The TSS believes this is a reasonable proxy in the circumstances and conforms to the principles and intent of this component of the Rule given this MTO's circumstance.* In the Auditor's opinion, in their filed audited Annual Report on page 40, lines 33-50, HG&E directly assigned O&M costs to transmission accounts including Accounts 561 and 565. In the Interpretative Guidance Document, the TSS

believed that HG&E did not directly assign its O&M expenses to transmission. If HG&E had incorrectly assigned transmission O&M costs to other accounts, then HG&E should revise its annual filing as required of all other TOs. The Auditor believes that HG&E O&M costs are audited before filing and as such should reflect HG&E O&M directly assigned costs. The Auditor sees no need to apply a different formula. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

8. Transmission Related Administrative and General Expenses are out of compliance with Section II.H., NEPOOL Tariff, Attachment F. In the original template, the formula was incorrect. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

9. Property Insurance is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. The workpapers provided by HG&E on worksheet 96A Unexpired Insurance Acct#165-00/924-00, include line 10 of $51,130 in the revenue requirement calculation that is NEPPA – Hartford: Property Boiler & Machinery. On line 1 of this workpaper, the line item is labeled the same as line 10, but the amount of $4,095 is not included. Furthermore, the total electric shown on this workpaper is $141,040. The Annual Report shows Property Insurance to be $131,241. Subsequently,

HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

10. Plant Allocation Factor is out of compliance with Section I.A.3., NEPOOL Tariff, Attachment F. HG&E did not include General-Related Plant in their calculation. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

HG&E filed a revenue requirement of $817,669 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, HG&E is out of compliance. Subsequently, HG&E submitted an updated revenue requirement of $509,677 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, HG&E is in compliance with the applicable rules for this rate period.

1997

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

3. General Plant Accumulated Depreciation is out of compliance with Section II.A.1.(d), NEPOOL Tariff, Attachment F. The Annual Report shows that Accumulated Depreciation should be $1,558,083 ($4,423,300 - $2,865,217 = $1,588,083). Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. HG&E excluded $2,027,127 shown in the Annual Report for Account 165. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

5. Amortization of Loss on Reacquired Debt is out of compliance with Section II.A.1.(f), NEPOOL Tariff, Attachment F. HG&E excluded $41,459 shown in the Annual Report for Account 428. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

6. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

7. Transmission O&M expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 7. above. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

8. Transmission Related Administrative and General Expenses are out of compliance with Section II.H., NEPOOL Tariff, Attachment F. In the original template, the formula was incorrect. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

9. Property Insurance is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. The workpapers provided by HG&E on worksheet 97A Unexpired Insurance Acct#165-00/924-00, include line 1 of $62,498 in the revenue requirement calculation that is NEPPA – Hartford: Property Boiler & Machinery. On line 10 of this workpaper, the line item is labeled the same as line 10, but the amount of $4,260 is not included. Furthermore, the total electric shown on this workpaper is $152,123. The Annual Report shows Property Insurance to be $146,026. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

10. Plant Allocation Factor is out of compliance with Section I.A.3., NEPOOL Tariff, Attachment F. HG&E did not include the General-Related Plant in

their calculation. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

HG&E filed a revenue requirement of $855,631 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, HG&E is out of compliance. Subsequently, HG&E submitted an updated revenue requirement of $716,790 for Pre-97 and $20 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, HG&E is in compliance with the applicable rules for this rate period.

1998

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

3. Gross Plant is out of compliance with Section II.A.1.(a), NEPOOL Tariff, Attachment F. HG&E in their filing used $59,040,917. The Annual Report shows Gross Plant to be $60,333,667. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

4. Net Transmission Plant is out of compliance with Section II.A.1.(a), NEPOOL Tariff, Attachment F. HG&E used in their filing $25,521,983. The Annual Report shows Net Plant to be $26,823,197. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. HG&E excluded $2,827,777 shown in the Annual Report for Account 165. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

6. Amortization of Loss on Reacquired Debt is out of compliance with Section II.A.1.(f), NEPOOL Tariff, Attachment F. HG&E excluded $41,459 shown in the Annual Report for Account 428. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

7. Property Taxes is out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

8. Transmission O&M expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

9. Transmission Related Administrative and General Expenses are out of compliance with Section II.H., NEPOOL Tariff, Attachment F. In the original template the formula was incorrect. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

10. Property Insurance is out of compliance with Section II.H., NEPOOL Tariff, Attachment F. The workpapers provided by HG&E on worksheet 98A Unexpired Insurance Acct#165-00/924-00, include $52,539 in the revenue requirement calculation that is NEPPA – Hartford: Property Boiler & Machinery. In addition, the workpaper shows a line item labeled the same, but in the amount of $5,208. This was not included. Furthermore, the total shown on this workpaper is $236,480. The Annual Report shows

Property Insurance to be $135,455. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

11. Plant Allocation Factor is out of compliance with Section I.A.3., NEPOOL Tariff, Attachment F. HG&E did not include the General-Related Plant in their calculation. Subsequently, HG&E submitted updated information that, in the Auditor's opinion, is in compliance.

HG&E filed a revenue requirement of $814,474 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, HG&E is out of compliance. Subsequently, HG&E submitted an updated revenue requirement of $692,381 for Pre-97 and $120 for Post-96 with supporting documentation that incorporates the above findings. Based upon the new information, in the Auditor's opinion, HG&E is in compliance with the applicable rules for this rate period.

c. Participant's Comments and Auditor's Response

Participant Comment:
HG&E does not believe that municipal transmission owners ("MTO") were parties to the discussions leading to the establishment of the Attachment F Rules, and it became very apparent during the audit process that interpretation or application of the Attachment F Rules to MTOs was a primary source of disagreements arising in the audit process. Many of the PTF Rules do not directly apply to MTOs, therefore requiring the exercise of appropriate and reasonable judgment to interpret and apply them to a MTO to produce a result that is consistent with the intent of the Rules. HG&E disagrees with the Auditor's application and interpretation with respect to several provisions of the rules.

Municipal Tax Expense is one of these areas that HG&E disagreed with the Auditor, yet conceded with Auditor's recommendation in order to reach an "In Compliance" status. The Auditor feels that payment in lieu of taxes (PILOT) is the only component that can be included in Property Taxes, while HG&E strongly feels that PILOT alone is not representative of HG&E's total payment to the City of Holyoke.

HG&E reserves it's right to comment on or otherwise address any and all aspects of the final NEPOOL RNS Audit Report and any responses filed or positions taken by any other NEPOOL transmission owner or market participant in any dispute before the Federal Energy Regulatory Commission or in any other appropriate forum.

Auditor's Response:
No response to the TO comment.

A.10 New England Power Company (NEP)

a. PTF and Non-PTF Findings

NEP provided one-line diagrams for each substation that clearly marked PTF and non-PTF facilities, and, also provided a system-wide map.

NEP provided very detailed plant accounting records for each of the three years (1996, 1997, and 1998). The Auditor, found in many cases, that although NEP had very detailed accounting information, its allocation to PTF and non-PTF reflected only a very limited number of cost items. A majority of the cost items, although very detailed, were assigned to common and not to PTF or non-PTF. This is critical in the cost assignment within transmission substations. The Auditors had expected that with amount of detail provided, a more complete PTF and non-PTF allocation could have been accomplished. NEP should review its allocation and assign more plant to PTF and non-PTF functions or use Attachment F, Section B, Paragraph 8 which is used in cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals." Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

The Auditor singled out the following substations because the Auditor believes that a better allocation should have been made.

1996:

Harriman, Bear Swamp, Adams, Palmer, Pratts Junction, Vernon, Moore, Northborough and Bellow Falls Substations

Transformers, circuit breakers, disconnect switches and other items were allocated to common instead of directly to PTF or non-PTF. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in Auditor's opinion, is in compliance.

Tewksbury 22

Transformer descriptions were not labeled in most cases (voltage or transformer number). Spare breakers should be non-PTF. Panels with voltage, line or other functional descriptions should be directly allocated and not assigned to common. Any items labeled distribution should be non-PTF. The switches should be allocated to a function and not to common. Most costs (about 70%) were assigned to common. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Sandy Pond, Ward Hill and Comerford Substations

A significant amount of costs were lumped into Account 106 and not classified. Based on the PTF rules, these costs should be allocated on the basis of the number of substation terminals serving PTF and non-PTF facilities. The Auditor and NEP differ on the number of terminals to be used. NEP requested that the Reliability Committee (RC) provide interpretative guidance. The RC confirmed the Auditor's interpretation. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Wilder, Webster, Royalston, and Chestnut Hill Substations

These substations should be all non-PTF. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

South Wrentham

Three breakers were allocated to PTF, but the one-line diagram only shows two. Well over 50% of the costs were assigned to common. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. It seems PTF plant was overstated. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Summary

The originally filed PTF plant by NEP for 1996 is out of compliance. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

1997/1998:

Harriman

Refer to 1996 for comments. Also, Transformers #1 and #2 costs are shown as part of US Gen in the one-line diagram. However, the costs are shown in NEP's plant cost. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Fitch Pond, Comerford, South Danvers, Greendale, Ayers, Chestnut Hill, Read Street, Park Street, Revere, Wilder, Everett, Webster, Chartley Pond, Carpenter Hill, Lynn, West Methuen, East Methuen and Beaver Pond Substations

Most cost items were assigned to common. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Bellow Falls

Refer to 1996 for comments. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Royalston

Two load breakers were assigned to PTF. Based on the one-line diagram, they should be assigned to non-PTF. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Sandy Pond

The one-line diagram shows seven non-PTF breakers while the cost assignment only shows five. Other airbreak and disconnect non-PTF switches were not accounted for. Over 50% of cost items were assigned to common. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Otter River

Control House should be assigned to common and not to PTF. The airbreak switches allocation does not follow the one-line diagram. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

106 Plant Investment

The '106' plant in service for NEP substations is about 10% of the total plant investment and over $54 million in total for 1998. A major '106' plant investment was associated with each of the Ward Hill, Brayton Point Common, Union, Millbury and Uxbridge substations. NEP assigned its substation '106' plant investment between PTF and non-PTF functions on the basis of specific substation "Project Sheets" documentation. These "Project Sheets" did not generally provide enough detailed information of the costs to make the PTF and non-PTF allocation. In cases where the "major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities." See Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in Auditor's opinion, is in compliance.

Summary

The originally filed PTF plant by NEP for 1997 and 1998 is out of compliance. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

ii Narragansett

1996/1997/1998:

Franklin Square

Eighty percent of the substation cost or about $4 out of $5 million was assigned to common. The Auditor recommends using Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Drumrock

NEP assigned all plant items to PTF. After reviewing the cost items and the one-line diagram, the Auditor concluded that this substation performs both PTF and non-PTF functions. The Auditor recommends using Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

"106 Plant" Investment

Most of Naragansett's substation plant investment is in '106' plant, $40 million out of $49 million. This major substation-rebuilding project included the reconstruction of two PTF 115KV underground transmissions lines at a cost of approximately $26 million. Consequently, the Auditor recommends using Attachment F, Section B, paragraph 8. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Summary

The originally filed PTF plant by Narragansett for 1996, 1997 and 1998 is out of compliance. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. PTF Plant in Service as originally filed is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, NEP filed updated information that, in the Auditor's opinion, is in compliance.

2. NEP, in their rate base calculation, excluded $5,869,364 of HVDC that NEP determined was PTF investment. The Auditor reviewed the workpaper provided and determined NEP miscalculated the portion of PTF investment for HQ leases that should be included. For the Comerford to Tewksbury line, NEP used 120 miles in their calculation, while in their FF#1, page 422, line 20, NEP reported 126.4 miles. For the land cost from Sandy Pond to New Hampshire, NEP used $1,253,646. This amount is for the Tewksbury to Amesbury, MA line, not Sandy Pond to New Hampshire. The FF#1, page 423, line 6 shows $1,106,146. Making these corrections will change the HQ PTF investment exclusion from $5,869,364 to $5,584,165. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Wages & Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. The FF#1, page 354, line 19, reported $4,068,141 for transmission-related wages and salaries. NEP used $4,067,500 in their filing. NEP had no input for Administrative

and General Wages and Salaries (A&GWS). In the FF#1, page 354, line 24, reported $3,666,744. For total Wages and Salaries (TW&S), NEP used $47,376,293, while the FF#1, page 354, line 25, shows $51,277,717. Netting the FF#1 total and the FF#1 A&GWS, produces a net amount of $47,610,973 which is $234,680 higher than the TW&S used by NEP. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

NEP filed a revenue requirement of $59,747,893 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, NEP is out of compliance. Subsequently, NEP submitted an updated revenue requirement of $60,218,587 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, NEP is in compliance with the applicable rules for the rate period.

1997

1. PTF Plant in Service as originally filed is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

2. NEP in their rate base calculation excluded $5,304,767 of HVDC that NEP had determined was PTF investment. The Auditor reviewed the

workpaper provided and determined NEP miscalculated the portion of PTF investment for HQ leases that should be excluded. For the Comerford to Tewksbury line, NEP determined the Gross Plant to be $5,232,248, not including land. For 1996 and 1998, NEP did include land for this line. To be consistent with the 1996 and 1998 treatment, the Auditor included land costs which increased the total line cost for 1997 from $5,232,248 to $5,991,855 as in FF#1, page 423, line 20. In addition, NEP used 120 miles in their calculation, while the FF#1, page 422, line 20 NEP shows 126.4 miles. For total land cost from Sandy Pond to New Hampshire, NEP used $1,253,646. This amount is for the Tewksbury to Amesbury, MA line, not Sandy Pond to New Hampshire. The FF#1, page 423, line 8 shows $1,106,146. Making these corrections changes the HQ PTF investment exclusion from $5,304,767 to $5,719,902. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Wages and Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. The FF#1, page 354, line 19 NEP reported $4,310,032 for transmission expense related wages and salaries. NEP used $4,309,641 in their filing. NEP had no input for Administrative General Wages and Salaries (A&GWS). In the FF#1, page 354, line 24, NEP reported $4,649,749. For total Wages and Salaries (TW&S), NEP used $49,690,197, while in the FF#1, page 354, line 25,

NEP shows $53,724,155. Netting the FF#1 total and the FF#1 A&GWS, produces a net amount of $49,074,406 which is $615,791 lower than the TW&S used by NEP. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

NEP filed a revenue requirement of $65,702,930 for Pre-97 and $7,196,715 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, NEP is out of compliance. Subsequently, NEP submitted an updated revenue requirement of $66,324,392 for Pre-97 and $7,359,480 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, NEP is in compliance with the applicable rules for the rate period.

1998

1. The 1998 RNS Revenue Requirement is out of compliance with the NEPOOL Tariff, Attachment F which requires the use of year-end balances. NEP used a post- and pre-divestiture allocation. The Auditor was unable to verify if the pre/post allocations were applied to all cost components. NEP should re-file their RNS Revenue Requirement for 1998 based on FF#1 year-end inputs. NEP responded by stating that *these adjustments were made to ensure that no over-allocations to transmission were made as a result of the full effect divestiture being reflected in NEP's plant balances at year end, while the expense reflected 8 months of*

Generation and Transmission related costs and 4 months of 'transmission only costs'. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

2. Other Regulatory Assets is out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F. NEP omitted FAS 106 in the amount of (-$347,800) as shown in the FF#1. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Wages and Salaries Allocation Factor is out of compliance with Section I.A.1., NEPOOL Tariff, Attachment F. NEP shows total Wages and Salaries on Worksheet 5, line 18 of $34,026,692, while the FF#1 total on page 354, line 25, is $39,670,834. Additionally, NEP had no input for Administrative General Wages and Salaries, while the FF#1, page 354, line 24 NEP shows $2,376,723. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

4. Plant Allocation Factor is out of compliance with Section I.A.3., NEPOOL Tariff, Attachment F. NEP used a post- and pre-divestiture allocation. The rules specify that costs should be from FF#1 for the year ending only. See further explanation in 1998 1. above. Subsequently, NEP submitted updated information that, in the Auditor's opinion, is in compliance.

Appendix A

NEP filed a revenue requirement of $63,850,552 for Pre-97 and $9,702,767 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, NEP is out of compliance. Subsequently, NEP submitted an updated revenue requirement of $66,712,722 for Pre-97 and $11,793,509 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, NEP is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
National Grid USA (National Grid) has no additional comments at this time to the RNS Audit Report. However, National Grid reserves its rights to object to any of the conclusions presented by Rhema Services, Incorporated ("RSI") in their audit report of the revenue requirements calculations for the NEPOOL Regional Network Service (RNS) rates in effect June 1, 1997 through May 31, 2000 after the required audit informational filing is made with the Federal Energy Regulatory Commission (FERC). RSI performed the audit on behalf of ISO New England Inc. National Grid also reserves its rights to comment on any responses filed or positions taken by any entity in any dispute that arises after the audit report informational filing is made with the FERC. Particularly, National Grid reserves its rights related to any comments or responses to the Audit's findings on New England Power's 1998 Divestiture Adjustment.

National Grid is providing these comments on behalf of its subsidiaries, New England Power Company and The Narragansett Electric Company (Narragansett Electric), and on behalf of the former Eastern Utilities Associates (EUA) and its former subsidiaries, Blackstone Valley Electric Company, Eastern Edison Company, Montaup Electric Company, and the Newport Electric Corporation.

Auditor's Response:
No response to the TO comment.

A.11 Northeast Utilities (NU)

a. PTF and Non-PTF Findings

NU provided adequate system one-line diagrams that were color-coded to separately identify the PTF and non-PTF lines. Substation one-line diagrams were provided with adequate detail to provide a basis for assessing the division of station equipment between PTF and non-PTF facilities.

Initially, NU provided supporting cost detail that depicted the methodology employed to separate PTF and non-PTF costs. NU's initial method involved the development and use of additional allocation ratios to separate and assign costs among PTF and non-PTF categories. For example, the land use ratios to assign land, fencing and site work was based on an engineer's assessment of the land attributed to different functions. Bus work and substation structures were distributed based on an engineering assessment of the portion of each associated with different functions.

The PTF Rules provide to the extent practical a consistent, verifiable, straightforward and expeditious approach. The method used by NU introduces a number of subjective determinations, added effort, and produces results that can not be readily audited. The relevant language from Section B, Rule 7, is as follows:

> Other facilities - The investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a non-PTF function and general overheads shall be allocated to the PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of those facilities that are identified as serving PTF and non-PTF functions; the equipment cost of power transformers shall be excluded in this calculation for determining the division of investment, since this would produce a distorted balance.

NU interpreted the above language to provide for a two step allocation process to address the facilities that could not be directly assigned as PTF or non-PTF. The first step deals *with the investment in land, structures, ground mats, fences, ducts, lighting, etc.* NU separately identified these facilities and developed ratios to assign the associated costs. The second step relates to the investment in *other facilities.* NU defined other facilities to be those facilities that were not directly assigned or otherwise allocated to PTF and non-PTF.

Another interpretation of Section B, Rule 7 is that only a one-step allocation process is envisioned. The one-step allocation process is more straight-forward and easier to apply, less subjective, more readily tested by the audit process and should provide greater consistency among the TOs. In the audit process, an attempt was made to test the difference between the NU two-tier allocation approach, referred to as the NU Method, and the single tier allocation method, referred to as the Standard NEPOOL Method. Four substations were tested, and after review of the forgoing, the Auditor was unable to conclude that the differences in results between the NU Method and Standard NEPOOL Method were not material.

The Auditor was not able to verify whether or not NU's methodology would produce comparable results obtained using the method employed by all other TOs. The Auditor would need to verify a number of allocators developed by NU for each of its 129 substations. Many of these allocators would require subjective engineering judgement that would vary depending on the engineer doing the allocation. This would lead to significant differences among all TOs. If the NU methodology were adopted by all TOs, the results for each of the TOs' similar type substations could widely differ. This would be contrary to the goal of having a formula rate where the intent is to achieve similar rate treatment for all TOs cost allocations.

- NU's original submittal did not provide a detailed plant split between PTF, non-PTF, common and transformers for all the transmission investments as provided by all the other TOs.

- Summaries showing the sum of PTF plus transformers and common were not provided in a form that could be readily reviewed and audited. The same is true for non-PTF.

- NU provided a matrix to summarize and compare the tier one allocation-factors employed. Although this was helpful for purposes of an overview of the allocation ratios used, the Auditor is of the opinion that the first tier of the tier allocation process is an added complexity that may produce inconsistent results. Also, as noted above, the Auditor was not able to verify that consistent methodologies were employed by NU throughout the allocation process.

- Account 106 additions and retirements costs summaries were not provided for either substation or line by designated names. These account 106 costs were not summarized with account 101 costs, thus the Auditor was unable to determine how 106 costs were allocated to PTF and non-PTF.

- The Auditor was unable to summarize Millstone Units 1, 2 and 3 costs from individual unit summaries to the total summary.

- The costs provided for Seabrook seem to be the costs assigned to CL&P and WMECO only. NU did not provide the total Seabrook project transmission costs by FERC accounts plus the PTF, non-PTF, common and transformer costs incurred by NU and allocated to others. Also, the development of the allocation ratios and the rationale employed was not provided.

In the most recent submittal, NU prepared spreadsheets to summarize and reformat the detailed data contained in their initial submittal to utilize the Standard NEPOOL approach to allocating the common facilities. The NU information required a two step verification process by the Auditor and therefore was more difficult and labor intensive than the format followed by other TO's.

A number of differences were noted during the Auditor's review. For instance, NU had a significant number of substations with more than $200,000 of unclassified, or un-unitized cost data. NU provided some explanations in the form of hand written entries on the hard copy of its accounting records and/or notes added on the spreadsheets summaries. These notes were used by NU as guidance for purposes of assigning such costs among PTF, non-PTF, transformers and common categories. The Auditor determined that these costs should be allocated using Rule 8 of the PTF Rules, that is, employing the number of substation terminals.

Appendix A

There were other areas of differences as follows:

- In a few instances, the count of major equipment items (OCB's, switches, lightning arresters) on one-line diagrams differed from the count of items contained in the cost data.

- Descriptive data indicated some errors in the assignment of other cost items among PTF, Non-PTF, transformers and common categories (bus structures, bus work, switchboards, instrument transformers, conduit and cables, and foundations).

- Equipment count ratios used to allocate certain categories of equipment differed from the ratios that the Auditor believed should have been used.

The Tables below summarize the results of the Auditor's findings based on NU's re-submitted PTF substation plant costs.

Comparison of PTF Investment For 1996
Developed By NU and as Validated By the Auditor

Batch 1	15	$ 84,452,499	$ 85,122,614	$ 670,116
Batch 2	21	0	0	0
Batch 3	29	1,063,473	1,015,575	(47,898)
Batch 4	26	23,455,654	22,880,166	(575,487)
Batch 5	19	31,378,493	29,306,287	(2,072,206)
Batch 6	19	23,608,853	22,355,767	(1,253,086)
Total	129	$ 163,958,972	$ 160,680,410	$ (3,278,562)
Percent Change				-2.04%

Comparison of PTF Investment For 1997
Developed By NU and as Validated By the Auditor

Batch 1	15	$ 100,455,020	$ 98,998,646	$ (1,456,374)
Batch 2	21	10,176,234	11,235,083	1,058,849
Batch 3	29	12,971,373	13,561,167	589,795
Batch 4	26	37,891,684	37,221,121	(670,563)
Batch 5	19	39,253,169	37,792,927	(1,460,243)
Batch 6	19	30,073,754	29,881,086	(192,667)
Total	129	$ 230,821,234	$ 228,690,030	$ (2,131,204)
Percent Change				-0.93%

Appendix A

Comparison of PTF Investment For 1998
Developed By NU and as Validated By the Auditor

Batch 1	15	$ 100,039,566	$ 98,744,313	$ (1,295,253)
Batch 2	21	10,906,899	11,570,869	663,970
Batch 3	29	13,443,736	14,408,871	965,135
Batch 4	26	37,922,332	36,733,808	(1,188,525)
Batch 5	19	39,465,870	37,738,741	(1,727,129)
Batch 6	19	30,103,118	30,083,210	(19,908)
Total	129	$ 231,881,522	$ 229,279,812	$ (2,601,710)
Percent Change				-1.13%

The originally filed PTF plant by NU for 1996, 1997 and 1998 is out of compliance. NU did not submit summary sheets tying in its total transmission plant investment with the actual FERC filed transmission plant data. Also, NU did not submit its PTF plant data for the pre-1997 or post-1996 periods. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings:

i. Connecticut Light & Power Company (CL&P)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. CL&P failed to use year-end amounts from FF#1 to

determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by CL&P at FERC changes the overall rate of return from the 8.56% used by CL&P to 8.62%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of CL&P, a revenue requirement of $48,064,514 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, CL&P is out of compliance. Subsequently, NU submitted an updated revenue requirement of $48,736,117 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CL&P is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. CL&P failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by

CL&P at FERC changes the overall rate of return from the 8.40% used by CL&P to 8.66%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

3. Total Accumulated Deferred Income Tax (ADIT) FERC Account #190 is out of compliance with Section II.A.1.(e), NEPOOL Tariff, Attachment F. The FF#1 shows ADIT to be $232,430,130. CL&P in their revenue requirement filing used $256,980,774. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of CL&P, a revenue requirement of $48,372,872 for Pre-97 and $1,447,402 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, CL&P is out of compliance. Subsequently, NU submitted an updated revenue requirement of $49,164,501 for Pre-97 and $1,543,396 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CL&P is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. CL&P failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by CL&P at FERC changes the overall rate of return from the 8.70% used by CL&P to 8.68%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of CL&P, a revenue requirement of $48,163,093 for Pre-97 and $1,746,859 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, CL&P is out of compliance. Subsequently, NU submitted an updated revenue requirement of $48,434,167 for Pre-97 and $ 1,678,091 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, CL&P is in compliance with the applicable rules for the rate period.

ii. Holyoke Power & Electric Company (HP&EC)

1996

NU filed, on behalf of HP&EC, a revenue requirement of $152,316 for the rate period 6/1/97 to 5/31/98. In the Auditor's opinion, HP&EC is in compliance with the applicable rules for the rate period. Subsequently, NU elected to submit an updated revenue requirement of $151,014 with supporting documentation that incorporates the above findings.

1997

NU filed, on behalf of HP&EC, a revenue requirement of $129,046 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. In the Auditor's opinion, HP&EC is in compliance with the applicable rules for the rate period. Subsequently, NU elected to submit an updated revenue requirement of $128,045 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings.

1998

NU filed, on behalf of HP&EC, a revenue requirement of $90,493 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. In the Auditor's opinion, HP&EC is in compliance with the applicable rules for the rate period. Subsequently, NU elected to submit an updated revenue requirement of $94,283 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings.

iii. Holyoke Water Power Company (HWPC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. HWPC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by HWPC at FERC changes the overall rate of return from the 7.03% used by HWPC to 6.46%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of HWPC, a revenue requirement of $81,171 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, HWPC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 72,396 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, HWPC is in compliance with the applicable rules for the rate period.

Appendix A

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. HWPC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by HWPC at FERC changes the overall rate of return from the 6.45% used by HWPC to 6.41%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of HWPC, a revenue requirement of $69,285 for Pre-97 and $ 0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, HWPC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 77,878 for Pre-97 and $ 0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, HWPC is in compliance with the applicable rules for the rate period.

Appendix A

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. HWPC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by HWPC at FERC changes the overall rate of return from the 6.72% used by HWPC to 6.80%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of HWPC, a revenue requirement of $69,038 for Pre-97 and $ 0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, HWPC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 77,952 for Pre-97 and $ 0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, HWPC is in compliance with the applicable rules for the rate period.

iv. Public Service Company of New Hampshire (PSCNH)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. PSCNH failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by PSCNH at FERC changes the overall rate of return from the 9.66% used by PSCNH to 9.99%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of PSCNH, a revenue requirement of $15,335,737 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, PSCNH is out of compliance. Subsequently, NU submitted an updated revenue requirement of $15,118,544 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, PSCNH is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. PSCNH failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by PSCNH at FERC changes the overall rate of return from the 9.53% used by PSCNH to 9.66%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

3. Total Accumulated Deferred Taxes (ADIT) FERC Account #190 is out of compliance with Section II.A.1.(e), NEPOOL Tariff, Attachment F. The FF#1 on page 111, line 66 (d) shows $234,251,451. PSCNH's in the revenue requirement filed 234,438,801. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of PSCNH, a revenue requirement of $15,095,551 for Pre-97 and $34,274 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, PSCNH is out of compliance. Subsequently, NU submitted an updated revenue requirement of

$ 15,339,474 for Pre-97 and $25,933 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, PSCNH is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. PSCNH failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by PSCNH at FERC changes the overall rate of return from the 9.88% used by PSCNH to 10.50%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of PSCNH, a revenue requirement of $14,110,200 for Pre-97 and $70,073 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, PSCNH is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 14,478,960 for Pre-97 and $57,018 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, PSCNH is in compliance with the applicable rules for the rate period.

v. North Atlantic Energy Corp. (NAEC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. NAEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by NAEC at FERC changes the overall rate of return from the 10.77% used by NAEC to 11.10%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of NAEC, a revenue requirement of $1,735,790 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, NAEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $2,019,650 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, NAEC is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. NAEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by NAEC at FERC changes the overall rate of return from the 10.92% used by NAEC to 11.06%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of NAEC, a revenue requirement of $2,158,215 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, NAEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 2,067,081 for Pre-97 and $ 158,550 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, NAEC is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. NAEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by NAEC at FERC changes the overall rate of return from the 10.99% used by NAEC to 11.14%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of NAEC, a revenue requirement of $2,227,018 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, NAEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $2,139,257 for Pre-97 and $ 153,348 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the

Auditor's opinion, NAEC is in compliance with the applicable rules for the rate period.

vi. Western Massachusetts Electric Co. (WMEC)

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. WMEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by WMEC at FERC changes the overall rate of return from the 9.12% used by WMEC to 9.38%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of WMEC, a revenue requirement of $8,203,195 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, WMEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 7,792,081 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, WMEC is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. WMEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by WMEC at FERC changes the overall rate of return from the 8.87% used by WMEC to 8.83%. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

3. For Total Accumulated Deferred Taxes (ADIT) FERC Account #190 is out of compliance with Section I.A.1.(e), NEPOOL Tariff, Attachment F. The FF#1 on page 111, line 66, column (d) shows a year end balance of $36,462,682. WMEC in the revenue requirement filed $41,880,250. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of WMEC, a revenue requirement of $8,801,696 for Pre-97 and $565,123 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, WMEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 8,545,038 for Pre-97 and $609,692 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, WMEC is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. WMEC failed to use year-end amounts from FF#1 to determine both the capital structure and the weighted cost of capital. Using the year-end amounts from the FF#1 and the methodology filed by WMEC at FERC changes the overall rate of return from the 9.30% used by WMEC to 9.22%. Subsequently, NU filed updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for detailed explanation of the finding. Subsequently, NU submitted updated information that, in the Auditor's opinion, is in compliance.

NU filed, on behalf of WMEC, a revenue requirement of $9,462,441 for Pre-97 and $655,910 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, WMEC is out of compliance. Subsequently, NU submitted an updated revenue requirement of $ 9,202,104 for Pre-97 and $679,824 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, WMEC is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
Regarding the above referenced Audit Report, NU has no comments or challenges of a substantive nature at this time, but reserves its right to respond further to comments of other transmission owners, and to participate and/or seek such remedies as it deems appropriate in any docket opened by the Federal Energy Regulatory Commission pertaining to this audit.

Auditor's Response:
No response to the TO comment.

A.12 Taunton Municipal Light Plant (TMLP)

a. PTF and Non-PTF Findings

TMLP provided an adequate one-line diagram to facilitate an assessment of their PTF eligible facilities. The network portion of the system consists of two 115 kV tap lines from two adjacent 115 kV circuits of EUA, which terminate in a six breaker ring-bus at the Cleary Station of TMLP. One tap line is 0.9 miles in length supplied from the EUA S8 Line. The other tap line is also 0.9 miles in length and is supplied from the EUA V5 Line. Both lines appear in the NEPOOL catalog and are operated normally closed, forming a network path between the V8 and V5 lines via the Cleary Station of TMLP. Two line disconnect switches are installed at the S8 line tap point and three line disconnect switches are installed at the V5 tap point. These disconnect switches were indicated as being PTF eligible facilities owned by TMLP.

In addition to the PTF eligible facilities identified above, two 115/13.8-kV substations are supplied from the Cleary Station through the ET and W lines. These facilities are operated in a radial fashion and are not PTF eligible facilities.

Supporting cost data submitted by TMLP was not detailed and the Auditor was unable to ascertain the cost of all power transformers, circuit breakers or switches. In addition, Attachment F, Section B, paragraph 8 could not be applied because the records provided were not sufficient to determine the cost by substation and transmission line.

Adequate data was not provided to allow verification that four items on the one-line diagram had been treated as non-PTF. The facilities in question are the W Line Ground Switch, the ET Line Ground Switch, the B6-2 transformer disconnect switch and the T9A-1 transformer disconnect switch.

The Auditor notes that 1996 costs were not presented in accordance with the version of PTF Rules that apply to 1996. Under the applicable rules for 1996, only one-third of the Cleary Ring Bus would be PTF. TMLP claimed the entire Cleary Substation as PTF.

Based upon the above audit exceptions, the Auditor finds the TMLP PTF cost submittal to be out of compliance for years 1996, 1997 and 1998. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive

Guidance Document that addressed the municipal cost of capital issue. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement filed $0. The DPUC Annual Report, page 10, line 26 shows this to be $766,071. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II. A.1.(i), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement filed $0. Based on the Interpretative Guidance Document, TMLP would be able to use $946,617 times the PAF times the PTF Factor. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Tax is in partial compliance with Section II.E., NEPOOL Tariff, Attachment F. TMLP used the Interpretative Guidance Document, and

provided an allocation using the payment in lieu of taxes amount, developing a ratio of transmission net plant to total net plant times payment in lieu of taxes. TMLP used $47,649,119 for total net plant. The DPUC Annual Report shows total net plant to be $46,452,188. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission O&M Expenses is out of compliance with Section II.G., NEPOOL Tariff, Attachment F. Workpapers were requested to review FERC Accounts 562 and 567 for any transmission support expenses already included in O&M. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

7. Regulatory Commission Expense calculation is out of compliance with Section II. H., NEPOOL Tariff, Attachment F. TMLP did not include Regulatory Commission Expense in the calculation after removing it from the total A&G expense. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

8. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. TMLP omitted payroll tax expenses from their revenue requirement calculations. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

9. Total Transmission Plant inputs are out of compliance with Section II.A.1., NEPOOL Tariff, Attachment F. The amount shown on Worksheet 5 of the template does not match the amount for Total Transmission Plant shown on Worksheet 3. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

TMLP filed a revenue requirement of $381,892 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, TMLP is out of compliance. Subsequently, TMLP submitted an updated revenue requirement of $247,272 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, TMLP is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement included $0. The DPUC Annual Report, page 10, line 26 shows this to be $729,105. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement included $0. Based on the Interpretative Guidance Document, TMLP should use $1,005,369 times the PAF times the PTF Factor. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. TMLP used the Interpretative Guidance Document, and provided an allocation using the payment in lieu of taxes amount, developing a ratio of transmission net plant to total net plant times payment in lieu of taxes. TMLP used $47,476,912 for total net plant. The DPUC Annual Report shows total net plant to be $44,702,553.

Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission O&M Expenses is out of compliance with Section II.G, NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

7. Regulatory Commission Expense is out of compliance with Section II. H., NEPOOL Tariff, Attachment F as explained in 1996 7. above. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

8. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. TMLP omitted payroll tax expenses from their revenue requirement calculations. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

9. Total Transmission Plant inputs are out of compliance with Section II.A.1., NEPOOL Tariff, Attachment F as explained in 1996 9. above. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

TMLP filed a revenue requirement of $367,705 for Pre-97 and $0 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, TMLP is out of compliance. Subsequently, TMLP submitted an updated revenue requirement of $239,724 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, TMLP is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance because municipal systems were not specifically addressed in the rules in Section II.A.2., NEPOOL Tariff, Attachment F. However, Auditor received the NEPOOL Interpretive Guidance Document that addressed the municipal cost of capital issue. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Plant Investment is out of compliance. See Section A above for a detailed explanation of the findings. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

3. Transmission Prepayments are out of compliance with Section II.A.1.(h), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement filed $0. The DPUC Annual Report, page 10, line 26 shows this to be

$2,225,574. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission Materials & Supplies are out of compliance with Section II.A.1.(i), NEPOOL Tariff, Attachment F. TMLP in their revenue requirement filed $0. Based on the Interpretative Guidance Document, TMLP should use $1,212,853 times the PAF times the PTF Factor. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

5. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. TMLP used the Interpretative Guidance Document, and provided an allocation using the payment in lieu of taxes amount, developing a ratio of transmission net plant to total net plant times payment in lieu of taxes. TMLP used $48,000,000 for total net plant. The DPUC Annual Report shows total net plant to be $44,559,090. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission O&M Expense is out of compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 6. above. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

7. Payroll Taxes are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. TMLP omitted payroll tax expenses from their revenue requirement calculations. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

8. Total Transmission Plant inputs are out of compliance with Section II.A.1., NEPOOL Tariff, Attachment F as explained in 1996 9. above. Subsequently, TMLP submitted updated information that, in the Auditor's opinion, is in compliance.

TMLP filed a revenue requirement of $336,342 for Pre-97 and $0 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, TMLP is out of compliance. Subsequently, TMLP submitted an updated revenue requirement of $219,695 for Pre-97 and $0 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, TMLP is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
TMLP has a number of substantive disagreements with the audit. Following its timely submittal of data initially requested by the Auditor, TMLP supplemented its submittal in response to preliminary comments by the Auditor by providing RSI and ISO-NE a significant amount of detail information from their accounting records in a format TMLP continues to believe fulfilled the Auditor's requirements.

The supplemental information provided by TMLP proved sufficient to resolve issues regarding the treatment of costs for every account except for Account 353 – Station Equipment. RSI recommended allocating the investment in this account by applying PTF Rules, Section B, Rule 8 (number of PTF terminals) which only allows 1/3 of the equipment to be counted as PTF.

TMLP believes and fully reserves its position that the proper PTF rule to apply is Rule 2 which effectively states that if a substation that serves both PTF and non-PTF lines provides parallel flow to the PTF system, then the whole substation should designated as PTF. Therefore, the entire plant investment at issue should be classified as PTF.

TMLP expressly reserves its right to submit written comments and to otherwise participate in any proceeding at the Federal Energy Regulatory Commission regarding this audit report. TMLP offers the following concluding comments: First, Attachment F to the NEPOOL OATT, the associated Implementation Rule and the PTF Cost Allocation Rules were developed without consultation with NEPOOL's municipal transmission owners, and without regard for differences between the accounting practices of investor-owned transmission owning utilities and those of their municipal counterparts. More flexibility should have been deployed in the audit in taking these differences into account than was the case. Second, TMLP has grave concerns about the processes by which the audit was conducted. Having proven unsuccessful in its effort to seek redress for those concerns in the audit process itself, TMLP will reserve those concerns to formal proceedings before the FERC.

Auditor's Response:
TMLP, similarly to all other TOs, received a comprehensive data request (Appendix E) from the Auditor on April 12, 2000. This data request listed the required information needed by the Auditor from TMLP to audit TMLP's RNS revenue requirement submitted to ISO NE. It is the Auditor's opinion that TMLP had sufficient time (April 2000 through Feb 2002) to provide, clarify and explain any information that TMLP believed was necessary to satisfy the Auditor's request. The audit process applied to TMLP was similar in time and effort to the process applied to all other TOs.

A.13 United Illuminating Company (UI)

a. PTF and Non-PTF Findings

UI provided system and substation one-line diagrams to facilitate an assessment of their PTF eligible facilities. The system diagrams lacked ownership change lines and some facilities were not appropriately marked as PTF. In many instances, names used to define transmission lines in the accounting records, as well as the PTF Catalog, were not shown on the system diagram.

Transmission line mileage data is the same for all three years. Lines in the PTF Catalog were checked against the system map, and after resolution of some initial questions the Auditor finds the maps and the catalog to be consistent. In many instances, the accounting data employed a different naming convention than the one used in the PTF Catalog. In some instances, the inconsistent naming convention precluded the Auditor from being able to fully verify the accuracy of the lines claimed as PTF. For example, line sections 9500 and 9502 are reported twice. Once under the name Grande – MR - Broadway – Water, and a second time as Water St. Sub – Mill River Sub. Although, it is possible that this refers to different sections of the same line, it appears questionable. Another possible issue is that the system diagram depicts some lines from double circuit lines as tap lines to connect to distribution transformers. This may simply reflect a drafting style, however, if short taps of non-PTF line exist, an assignment for non-PTF transmission costs would be appropriate for such connections between the PTF lines and these tap substations. As the Auditor discussed with UI representatives, the Auditor recommends that ownership change lines be reflected on their system diagrams. Additionally, the Auditor recommends that the system diagrams, PTF Catalog and accounting references to transmission lines be standardized by UI. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

UI has 19 distribution substations. The Auditor's interpretation of the 1996 rules identify facilities that were in part incorrectly assigned as PTF. In 1996, Millstone Generating Station Switchyard was incorrectly fully assigned to PTF. Under 1996 PTF Rules, none of Millstone Generation Station Switchyard should be assigned to PTF. In addition, a significant portion of the Seabrook station should be assigned to non-PTF. Seabrook's allocation should follow the same percentage used by NU for its Seabrook Substation.

The Auditor evaluated the supporting detail and methodology provided by UI for separating PTF and non-PTF cost elements in 1996. The Auditor found that many of the assignments of PTF costs, based on the Auditor's interpretation of the accounting entry descriptions, would support either assignment to common or alternatively some allocation between PTF and non-PTF. The PTF and non-PTF allocation could be based on the number of items (switches, lightning arresters, breakers, etc.) associated with the PTF and non-PTF elements. Additionally, accounting entries were made for two power transformers for the Grand Avenue Substation, which are not shown on either the system diagram or on the substation one-line drawing. Accordingly, based on this review, the Auditor questions a significant number of the cost entries for 1996.

An assignment of PTF costs was entered for the Skiff Street Service Building and the Western Service Station. The Auditor interprets this assignment as relating to the SCADA monitoring and control center facilities. The rules allow for inclusion of a prorated portion of the remote (Supervisory Control) and tele-metering facilities used in whole or in part for PTF purposes. The Auditor does not take issue with this approach, however it is not readily apparent as to what approach UI took for making its allocation.

Based upon the exceptions above, the Auditor's finds that the UI 1996 PTF substation cost is out of compliance. Subsequently, UI submitted updated information that in the Auditor's opinion, is in compliance.

Although, the Auditor finds that the approach taken for 1997 and 1998 to be generally thorough, instances exist where items have been allocated to

PTF, which the Auditor believes should be considered common or non-PTF. Other significant issues relate to the handling of breakers, disconnect switches and lightning-arresters. In many instances, an assignment of such facilities related to non-PTF transformer and other non-PTF facilities could not be found.

From the Auditor's examination, there appears to be a pattern throughout the substations that would result in inconsistent treatment of PTF cost allocations.

Based upon the exceptions above, the Auditor's finds that the UI 1997 and 1998 PTF plant in service is out of compliance. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. The Auditor reviewed the workpapers provided by UI, but was unable to follow the methodology used by UI or relate the cost of capital percentages and the capital structure amounts to FF#1 data. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the findings. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

3. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. UI did not include local property tax of $5,427,332 for the state of New Hampshire. The total amount of Property Taxes should be $24,854,415. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

4. Transmission O&M is partial compliance with Section II.G., NEPOOL Tariff, Attachment F. The FF#1, page 321, line 100 shows the amount to be $16,998,295, UI used $16,932,872. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Tax Expense is out of compliance with Section II.F., NEPOOL Tariff, Attachment F. UI did not include $639,750 of New Hampshire payroll tax in their calculation. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

UI filed a revenue requirement of $23,847,588 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, UI is out of compliance. Subsequently, UI submitted an updated revenue requirement of

$25,419,615 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, UI is in compliance with the applicable rules for the rate period.

Appendix A

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the findings. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

3. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. UI did not include local property tax of $5,195,840 for the state of New Hampshire. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

4. Regulatory Commission Expenses are out of compliance with Section II.H., NEPOOL Tariff, Attachment F. UI in the revenue requirement filed $39,070. Auditors reviewed FF#1, page 350, lines 15-21 and determined only $1,039 can be included as FERC assessments. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Tax expenses are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. UI did not include $795,955 of New Hampshire payroll tax in their calculation. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

UI filed a revenue requirement of $25,524,987 for Pre-97 and $193,776 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, UI is out of compliance. Subsequently, UI submitted an updated revenue requirement of $27,785,838 for Pre-97 and $238,944 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, UI is in compliance with the applicable rules for the rate period.

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF transmission plant is out of compliance as filed. See Section A above for detailed explanation of the findings. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

3. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. UI in their filing stated Property Taxes were functionalized,

therefore no need to use PAF Allocation. There is no functionalization shown in the FF #1, nor any workpapers provided to reconcile with what UI filed. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

4. Regulatory Commission Expenses are out of compliance with Section II.H., NEPOOL Tariff, Attachment F. UI in their revenue requirement filed $371,489. Auditors reviewed FF#1, page 350, lines 8-12 and determined only $361,155 can be included as FERC assessments. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

5. Payroll Tax Expenses are out of compliance with Section II.F., NEPOOL Tariff, Attachment F. UI did not include $774,819 of New Hampshire payroll tax in their calculation. Subsequently, UI submitted updated information that, in the Auditor's opinion, is in compliance.

UI filed a revenue requirement of $24,129,128 for Pre-97 and $231,491 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, UI is out of compliance. Subsequently, UI submitted an updated revenue requirement of $26,388,881 for Pre-97 and $318,687 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, UI is in compliance with the applicable rules for the rate period.

b. Participant's Comments and Auditor's Response

Participant's Comments:
The United Illuminating Company ("UI") has reviewed the final NEPOOL Regional Network Service (RNS) Audit Report For Rates in Effect June 1, 1997 Through May 31, 2000.

UI has no comments at this time regarding the results of the final audit report. However, UI reserves it's right to comment on or otherwise address any and all aspects of the final NEPOOL RNS Audit Report and any responses filed or positions taken by any other NEPOOL transmission owner or market participant in any dispute before the Federal Energy Regulatory Commission or in any other appropriate forum.

Auditor's Response:
No response to the TO comments.

A.14 Vermont Electric Power Company (VELCO)

a. PTF and Non-PTF Findings

VELCO provided actual accounting data for total plant as of December 31, 1998 and then worked backwards to develop year end 1997 and year end 1996 plant in service by removing additions or adding retirements to plant for those periods. An itemized list of plant costs was not provided for 1996 or 1997. The 1996 and 1997 additions and retirements were allocated to PTF or non-PTF on the basis of 1998 plant. Then, VELCO provided summary worksheets showing how PTF vs. non-PTF plant was determined. No itemized list of plant costs assigned to PTF or non-PTF was provided to verify VELCO's assignments. Instead, VELCO provided color-coded accounting records. It was up to the Auditor to sum all PTF and non-PTF allocations based on the color assignments. This would require a large amount of work by the Auditor that was not provided for in the audit scope.

The Auditors tested assignments to PTF by going through actual accounting records. Making these assignments according to the PTF rules, the Auditor computed the following in the first four substations audited.

Substation	PTF		% Difference
	Per VELCO	Per Auditors	
Essex	$1,466,710	$1,163,103	26.10%
Barre	274,246	181,588	51.03%
Ascutney	443,263	383,421	15.61%
No. Rutland	610,618	457,347	33.51%
Total	$2,969,657	$2,185,459	35.88%

Appendix A

The following substations do not qualify as PTF in 1996 according to the PTF Rules.

a) So. Hero
b) New Haven
c) Middlebury
d) Blissville
e) North Rutland
f) Cold River
g) Hartford
h) Chelsea
i) Barre
j) Berlin
k) Middlesex

There were enough discrepancies in the data for the Auditor to discontinue the PTF plant in service audit. Therefore, the Auditor consequently found VELCO's PTF plant out of compliance for 1996, 1997 and 1998. Subsequently, VELCO submitted updated information that, in the Auditors opinion, is in compliance.

b. RNS Template Input Findings

1996

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F. VELCO used beginning of year balances in calculating the cost of capital for LTD and Common Equity and excluded Preferred Stock. In addition, VELCO's ROE should be 11.50% not 8.00% as filed. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for a detailed explanation of the finding. Subsequently, VELCO filed updated information that, in Auditor's opinion, is in compliance.

3. Other Regulatory Assets/Liabilities are out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F. VELCO did do not include a credit of $2,615,327 shown in the FF#1, page 278, line 1, FAS 109 "Other Regulatory Liabilities," (FERC Account #254). Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F. Workpapers were not provided deriving the $1,676,964 and $212,038, for transmission and general payroll taxes, respectively.

Per Attachment F, the property tax amounts should be multiplied by the Plant Allocation factor and then multiplied by the PTF Transmission Plant Allocation factor. (1,889,002 x PAF x PTF). Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission O&M Expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F. VELCO made a direct subtraction for FERC Accounts 562 and 567 transmission support expenses from the transmission O&M amount allocated to PTF. The calculation would be to remove the transmission support expense from the PTF allocated column and subtract it from the Transmission O&M less FERC Accounts 561 and 565 before allocating to PTF. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission Rents Received from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. VELCO did not include FERC Account 454 in the amount of $25,455 for PTF rents received. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

VELCO filed a revenue requirement of $13,730,694 for the rate period 6/1/97 to 5/31/98. Based upon the above noted findings, in the Auditor's opinion, VELCO is out of compliance. Subsequently, VELCO submitted an updated revenue requirement of $13,284,744 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, VELCO is in compliance with the applicable rules for the rate period.

1997

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for a detailed explanation of the finding. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

3. Other Regulatory Assets/Liabilities are out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F as explained in 1996 3. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 4. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission O&M Expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 5. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission Rents Received from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. VELCO did not include FERC Account 454 in the amount of $16,935 for PTF rents received. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

VELCO filed a revenue requirement of $14,518,984 for Pre-97 and $142,842 for Post-96 for the rate period 6/1/98 to 5/31/99. Based upon the above noted findings, in the Auditor's opinion, VELCO is out of compliance. Subsequently, VELCO submitted an updated revenue requirement of $15,471,179 for Pre-97 and $110,523 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, VELCO is in compliance with the applicable rules for the rate period.

Appendix A

1998

1. Cost of Capital is out of compliance with Section II.A.2., NEPOOL Tariff, Attachment F as explained in 1996 1. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

2. PTF Transmission Plant is out of compliance. See Section A above for a detailed explanation of the finding. Subsequently, VELCO filed updated information that, in the Auditor's opinion, is in compliance.

3. Other Regulatory Assets/Liabilities are out of compliance with Section II.A.1.(g), NEPOOL Tariff, Attachment F as explained in 1996 3. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

4. Property Taxes are out of compliance with Section II.E., NEPOOL Tariff, Attachment F as explained in 1996 4. above. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

5. Transmission O&M expense is in partial compliance with Section II.G., NEPOOL Tariff, Attachment F as explained in 1996 5. above.

Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

6. Transmission Rents Received from Electric Property is out of compliance with Section II.O., NEPOOL Tariff, Attachment F. VELCO did not include FERC Account 454 in the amount of $13,801 for PTF rents received. Subsequently, VELCO submitted updated information that, in the Auditor's opinion, is in compliance.

VELCO filed a revenue requirement of $14,014,257 for Pre-97 and $218,213 for Post-96 for the rate period 6/1/99 to 5/31/00. Based upon the above noted findings, in the Auditor's opinion, VELCO is out of compliance. Subsequently, VELCO submitted an updated revenue requirement of $14,020,072 for Pre-97 and $174,925 for Post-96 with supporting documentation that incorporates the above findings. Based on the new information, in the Auditor's opinion, VELCO is in compliance with the applicable rules for the rate period.

c. Participant's Comments and Auditor's Response

Participant's Comments:
It is impossible for VELCO to agree fully with the audit findings, knowing that many of the determinations are incorrect. Throughout the analysis, equipment serving as an exclusive PTF function has been assigned an "Allocated" classification per the audit. VELCO has made every effort to provide information as requested throughout the audit, and in doing so has improved the quality of the data submitted. This improved data has allowed VELCO to more accurately identify equipment within the VELCO transmission system serving both PTF and Non-PTF functions.

The improved equipment classifications, according to the revised VELCO figures, has resulted in approximately $1M in additional PTF investment. It is understood that the full impact to VELCO will not be known until the entire audit of all TO's is finalized.

VELCO sees no need to submit any additional data at this time, and is willing to accept the auditors findings, provided the future audit for 1999-2000 include a review of all assets in VELCO's CPR, with reclassification where necessary. VELCO is confident that such a review will result in acceptance of the data submitted on August 21-22, and recommends that this review take place at the VELCO corporate office in Rutland, Vermont where supporting data is readily available.

Auditor's Response:
No response to the TO comments.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool	)	Docket Nos. OA97-237-000,
	)	ER97-1079-000, ER97-3574-000,
	)	OA97-608-000, ER97-4421-000
	)	and ER98-499-000

COMPREHENSIVE AGREEMENT RESOLVING ALL ISSUES RAISED IN THIS PROCEEDING EXCEPT FOR ONE ISSUE RAISED BY GREAT BAY POWER COMPANY (April 5, 1999)

To: The Honorable Lawrence J. Brenner
Presiding Administrative Law Judge

This settlement agreement (the "Settlement Agreement") is entered into by and among the following entities: New England Power Pool ("NEPOOL"); Bangor Hydro-Electric Company ("BHE"); Boston Edison Company ("BECO"); the Braintree Electric Light Department, Reading Municipal Light Department and Taunton Municipal Lighting Plant (collectively "BRT"); Central Maine Power Company ("CMP"); Central Vermont Public Service Corporation ("CVPS"); Commonwealth Electric Company, Cambridge Electric Light Company and Canal Electric Company (collectively "ComElec"); the Connecticut Municipal Electric Energy Cooperative, Chicopee Municipal Lighting Plant of the City of Chicopee, Massachusetts, the Westfield Gas and Electric Light Department of the City of Westfield, Massachusetts, and the South Hadley Electric Light Department (collectively, for purposes of this Settlement Agreement only, the "NU TDUs"); Fitchburg Gas and Electric Light Company ("Fitchburg"); ISO New England Inc. ("ISO NE"); the Massachusetts Municipal Wholesale Electric Company ("MMWEC"); Montaup Electric Company, on its own behalf and on behalf of the Eastern

Utilities Associates Operating Companies ("Montaup"); New England Power Company ("NEP"), Northeast Utilities Service Company on behalf of The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Water Power Company, and Public Service Company of New Hampshire (collectively referred to herein as "NU"); Sithe New England Holdings, LLC ("Sithe"); The United Illuminating Company ("UI"); Unitil Power Corp. ("Unitil"); US Generating Company, MASSPOWER, and Pittsfield Generating Co., L.P. (collectively "USGen"); and Vermont Electric Power Company ("VELCO"). The Settlement Agreement is for the purpose of fully and finally resolving all disputes between and among the signatories hereto (the "Parties") within the scope of the hearing in the proceedings established by the Federal Energy Regulatory Commission (the "Commission") in its April 20, 1998 Order, New England Power Pool, 83 FERC ¶ 61,045 (1998) (the "April 20 Order"). Commission Trial Staff ("Trial Staff") fully participated in the negotiation of this Settlement Agreement and fully supports it, as will be set forth in Staff's separately filed comments. The Parties hereby agree as follows:

A. The Settlement Agreement Does Not Resolve One Issue Raised by Great Bay. The only issue raised by Great Bay Power Company ("Great Bay") concerns its claim for reimbursement for support payments it makes for the Seabrook lines. That claim is not resolved in this Settlement Agreement, and remains to be resolved through an Initial Decision by the Presiding Administrative Law Judge and any subsequent Commission review of that Initial

Decision. The Parties are deemed to have reserved their positions with respect to Great Bay's claim, including their right to argue on brief that Great Bay's claim is not properly before the Presiding Administrative Law Judge and nothing in this Settlement Agreement shall impair the ability of any Party to litigate Great Bay's claim.

B. Agreement as to the NEPOOL-Staff Stipulation. (1) The Parties acknowledge and intend that the terms of, and understandings and agreements reached in, the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing (the "NEPOOL-Staff Stipulation") shall be incorporated into and made a part of this Settlement Agreement. The Parties agree that the terms of, and understandings and agreements reached in, this Settlement Agreement are not intended to and do not disturb, replace, limit, modify or otherwise effect the terms of, and understandings and agreements reached in the NEPOOL-Staff Stipulation, except with respect to Excepted Transactions and Return on Equity ("ROE") issues, which are resolved as set forth in this Settlement Agreement, and except with respect to the timing of the compliance filing described in Section 5 of the NEPOOL-Staff Stipulation, as set forth in subparagraph (2) below. The NEPOOL-Staff Stipulation has been executed by all of the active participants in these proceedings other than BRT, the NU TDUs, UI and Great Bay. A copy of the NEPOOL-Staff Stipulation, including all executed joinder pages, is included as Exhibit A to this Settlement Agreement.

(2) The compliance filing described in Section 5 of the NEPOOL-Staff Stipulation shall be made within sixty days of the Commission's final order approving this Settlement Agreement.

(3) To implement the terms of the NEPOOL-Staff Stipulation, Original Sheet Nos. 203 and 264 through 277 of the Restated NEPOOL Open Access Transmission Tariff (as filed on July 22, 1998) (the "NEPOOL Tariff" or "Tariff") shall be revised as set forth in Exhibit B to this Settlement Agreement.

C. Agreement Modifying the NEPOOL-BRT Stipulation. (1) NEPOOL and BRT agree, as between themselves, that upon execution of this Settlement Agreement by NEPOOL and BRT and approval by the Commission, the March 4, 1999 Joint Stipulation Among New England Power Pool Executive Committee and Braintree Electric Light Department, Reading Municipal Light Department and Taunton Municipal Lighting Plant Regarding Certain Issues Set for Hearing (the "NEPOOL-BRT Stipulation"), which was marked as Exhibit NPL-63 in these proceedings, shall be superseded by this Settlement Agreement and that the NEPOOL-BRT Stipulation shall be of no further force or effect.

(2) BRT agree that by executing this Settlement Agreement, BRT are deemed to have joined the NEPOOL-Staff Stipulation and agree to be bound by its terms.

(3) Notwithstanding BRT's decision to join this Settlement Agreement, the Parties agree that:

(a) with respect to Schedule 11 of the NEPOOL Tariff, BRT reserve their positions currently at issue in FERC Docket Nos. ER98-3853-000 and ER98-3853-001 with respect to the justness and reasonableness of (i) the allocation of system expansion costs proposed therein; and, (ii) the related provisions of proposed Sections 49 and 50 of the NEPOOL Tariff. All Parties are deemed to have reserved their positions with respect to BRT's claims.

(b) any issue between NEPOOL and BRT concerning the magnitude of adjustments and refunds attributable to the elimination of the non-PTF component of Transmission Related Integrated Facilities Charges with respect to NEP in accordance with Section 4 of the NEPOOL-Staff Stipulation shall be reserved to review and comment on the compliance filing or refund report submitted as set forth in that Stipulation;

(c) NEPOOL shall file with the Commission as part of the compliance filing referenced in Paragraph 5 of the NEPOOL-Staff Stipulation, Operating Procedure No. 8 and any other "applicable Operating Procedures for such services" referenced in Paragraph 13 of the NEPOOL-Staff Stipulation, and shall amend Operating Procedure No. 8 and any other "applicable Operating Procedures for such services" referenced in Paragraph 13 of the NEPOOL-Staff Stipulation only through filing with the Commission pursuant to Section 205 of the Federal Power Act. The current form of Operating Procedure No. 8 appears as Exhibit NPL-31 in the above-captioned proceedings.

D. Agreement as to the NEPOOL-MMWEC Letter Agreement. The Parties acknowledge and intend that the terms of, and understandings and agreements reached in, the March 2, 1999 agreement between NEPOOL and MMWEC (the "NEPOOL-MMWEC Letter Agreement") shall be incorporated into and made a part of this Settlement Agreement. The Parties further agree that the terms of, and understandings and agreements reached in, this Settlement Agreement are not intended to and do not disturb, replace, limit, modify or otherwise affect the terms of, and understanding and agreement reached in, the NEPOOL-MMWEC Letter Agreement, a copy of which is included as Exhibit C to this Settlement Agreement. The Parties agree that, upon Commission approval of this Settlement Agreement, Appendix 12-B-11 of Market Rule 12 shall be amended as necessary to implement the terms of the NEPOOL-MMWEC Letter Agreement.

E. Agreement as to the NU-NU TDU Offer of Settlement. The Parties acknowledge and intend that the terms of, and understandings and agreements reached in, the December 4, 1998 Offer of Settlement between NU and the NU TDUs (the "NU-NU TDU Settlement Offer") shall be considered a part of the overall settlement of the disputes in this proceeding, and that the terms of, and understandings and agreements reached in, this Settlement Agreement are not intended to, and do not, disturb, replace, limit, modify or otherwise effect the terms of, and understandings and agreements reached in, that Offer of Settlement, which is currently pending before the Commission. The NU TDUs further agree that by executing this Settlement Agreement, they shall be deemed to have joined the NEPOOL-Staff Stipulation.

F. Agreement Resolving BRT's Concerns Regarding Self-Supply Options With Respect to Ancillary Service Schedule 2. In addition to the agreements between NEPOOL and BRT set forth above, NEPOOL and BRT further agree to resolve BRT's concerns regarding self-supply options available under Ancillary Service Schedule 2 of the NEPOOL Tariff by modifying the language of that Schedule contained at Tariff Original Sheet No. 204 to read in accordance with the revised Tariff pages contained in Exhibit D attached hereto.

G. Agreement to Resolve Excepted Transactions Issues. All claims and potential claims of alleged double charges or overpayments resulting from the treatment of Excepted Transactions under the NEPOOL Tariff shall be resolved as set forth in this Section G of the Settlement Agreement. Revisions to the NEPOOL Tariff required to implement the changes identified in this Section G of the Settlement Agreement are contained in Exhibit E attached hereto.

(1) The phased-in transition of the pre-1997 Participant RNS Rate per Kilowatt to the pre-1997 Pool PTF Rate, as those terms are defined in the Tariff, and described in Section (2) of Schedule 9 of the Tariff at Original Sheet No. 226 shall be extended as set forth in Exhibit E.

(2) (a) The provisions of the NEPOOL Tariff in effect on the date of this Settlement Agreement relating to the phase-in of pre-1997 PTF costs to a NEPOOL system-wide Pool PTF Rate and the upper band width protection for such pre-1997 costs provide certain economic benefits and detriments to the Parties. In particular, UI may be adversely affected by changes that alter the phase-in of the Pool RNS Rate to the Pool PTF Rate. Other Parties believe that an ultimate move to zonal rates may be appropriate for the region going forward. To settle this case in light of these conflicting goals, the Parties have agreed to extend through December 31, 2003 the protections afforded to UI by the methodology used to recover pre-1997 PTF costs. This protection does not extend to any post-1996 PTF costs and does not prohibit adjustments to the Attachment F formula for determining Annual Transmission Revenue Requirements

("ATRR"). To reflect this agreement, Schedule 9 of the Tariff at Original Sheet Nos. 227 through 231 shall be revised as set forth in Exhibit E. It is further agreed that the limitation on further amendments to Schedule 9 does not apply to Attachment F for determining ATRR. Tariff Original Sheet Nos. 227 through 231 shall be revised as set forth in Exhibit E to reflect these understandings. Any division of Allocated Flows and ATRR agreed in this settlement, as reflected in the revisions to Section 16.6.A of the Restated NEPOOL Agreement, is subject to orders on rehearing currently pending and not withdrawn pursuant to Section L of this Settlement Agreement.

(b) The Parties further agree that the alternative version of Schedule 9 set forth in Exhibit J attached hereto shall be reviewed by the NEPOOL Regional Transmission Operations Committee and that Committee, within thirty (30) days of the execution of this Settlement Agreement, shall make a recommendation as to whether the alternative version of Schedule 9, or a substantially similar form of the alternative version of Schedule 9, should be adopted in accordance with the normal NEPOOL procedures for such matters. If such an alternative version of Schedule 9 is adopted, and the Parties to this Settlement Agreement approve in writing the adoption of such an alternative version of Schedule 9, such alternative version of Schedule 9 shall be filed in accordance with the compliance filing provisions of this Settlement Agreement and be in lieu of the Exhibit E version of Schedule 9.

(3) The Parties agree that, to the extent that a NEPOOL Transmission Provider's revenues for providing service under Parts II and III of the NEPOOL Tariff are decreased as a

result of this Settlement Agreement, without offsetting compensation under this Settlement Agreement or under a settlement in a Transmission Provider's Local Network Service ("LNS") Tariff case, such Transmission Provider shall be entitled to amend its LNS Tariff as necessary in a compliance filing to ensure recovery of the shortfall; such compliance filing, if any, shall be structured to ensure that the Transmission Provider does not overrecover its total cost of transmission; provided, however, that the payment of a share of the Phase I Uplift by a Transmission Provider shall not operate to increase any LNS charges payable by an entity receiving Phase I Credits. No payment for an Uplift Charge (as that term is used in this Section G of the Settlement Agreement) shall included in the calculation of ATRR.

(4) The NEPOOL Tariff shall be modified to include a new Section 25A to implement a portion of the agreement of the Parties for resolving all Excepted Transactions. The language of Section 25A, which is set forth in Exhibit E beginning at Original Tariff Sheet No. 92, shall provide in substance as follows:

(a) The following entities shall receive the following credits in total over the period June 1, 1999 through May 31, 2000 with respect to their Phase I Excepted Transaction payments (the "Phase I Credits"):

BHE	$896,000
MMWEC	$6,182,400
Braintree	$666,400
Reading	$1,430,240
Taunton	$479,360
UI	$280,000

Fitchburg	$117,600
Unitil	$1,960,000

The Phase I Credits for each entity are inclusive of any and all interest required by 18 C.F.R. Section 35.19a, and no further interest shall be paid provided such Credits are issued as set forth in the next sentence. The Phase I Credits shall be provided as reductions in each receiving entity's NEPOOL billings over the twelve-month period beginning June 1, 1999 and continuing through May 31, 2000, in accordance with NEPOOL's normal billing procedures. For each entity, its reduction each month will equal one-twelfth of its total Phase I Credit as listed in the table above.

(b) The Phase I Credits shall be funded by an uplift charge (the "Phase I Uplift") which will be in effect for the twelve month period beginning June 1, 1999 and continuing through May 31, 2000. The Phase I Uplift shall be paid monthly by all RNS and Internal Point-to-Point Transmission Customers under the NEPOOL Tariff, in accordance with NEPOOL's normal billing procedures, allocated based on load ratio with the following exceptions and limitations:

(i) VELCO shall be exempted from paying the Phase I Uplift.

(ii) BHE's monthly responsibility for the Phase I Uplift shall be based on 50 MW of load.

(iii) ComElec's monthly responsibility for the Phase I Uplift shall be based on 50% of its actual Network Load (excluding the load for Nantucket) and Internal Point-to-Point reservation, if any.

(iv) Montaup's monthly responsibility for the Phase I Uplift shall be based on 50% of its actual Network Load and Internal Point-to-Point reservation, if any.

(v) Taunton's monthly responsibility for the Phase I Uplift shall be $2,613.

The total amount of the Phase I Uplift not being paid by VELCO, BHE, ComElec, Montaup and Taunton as set forth above shall be borne by the remaining RNS and Internal Point-to-Point Transmission Customers, under the NEPOOL Tariff in accordance with the formula provided in the amended Tariff pages attached hereto.

(c) Except as provided in subparagraphs (d) and (e) below, for each Excepted Transaction listed in Attachment G to the NEPOOL Tariff that has been challenged in these proceedings as producing a double charge, the parties to the Transaction have agreed either to keep the contract in effect in accordance with its terms (as such terms may be amended pursuant to agreement of the parties thereto), or to cancel the contract effective March 1, 1999, as set forth in this Settlement Agreement, or to modify the contract as described in subparagraph (d) below.

(d) Certain of the Parties to this Settlement Agreement have negotiated side arrangements between and among them to resolve issues concerning specific Excepted Transactions to which they are parties. The agreements of these Parties have been memorialized in Exhibit F attached hereto and are submitted to the Commission for approval as part of this Settlement Agreement.

(e) Excepted Transactions listed in Attachment G to the NEPOOL Tariff that have not specifically been challenged in these proceedings, or negotiated or canceled as set forth in subparagraphs (c) and (d) above, shall remain in place according to their respective terms and the parties to those agreements shall be deemed to have waived any double charge complaint with respect to any such Excepted Transaction.

(f) MMWEC, on its own behalf, and on behalf of the six Massachusetts municipally-owned utilities which purchase output from MASSPOWER under contractual arrangements with MMWEC ("MMWEC's Customers"), has agreed to withdraw and waive any claim it has or may have to the effect that, unless modified, the NEPOOL Open Access Transmission Tariff, in conjunction with the Agreement for the Sale of Net Capability and Corresponding Energy By and Between MASSPOWER and Massachusetts Municipal Wholesale Electric Company, Version B (with Transmission) as amended (the "PPA"), would result in an overcharge to MMWEC's Customers, provided that this waiver shall be without prejudice to any rights of MMWEC, MMWEC's Customers or MASSPOWER in any contract renegotiation of the PPA.

(g) Exhibit G attached hereto contains revisions to NEPOOL Tariff Original

Sheet Nos. 278 through 282 reflecting the agreements of the Parties set forth in subparagraphs (c), (d), (e) and (f) above

(5) Certain provisions of the currently existing Section 25 of the NEPOOL Tariff shall be modified and a new Section 25B shall be added to the NEPOOL Tariff to implement the agreement of the Parties for resolving contracts and arrangements within the scope of Sections 25(1) and 25(2) of the NEPOOL Tariff (PPU, Yankee, Pilgrim and HQ Phase II) (collectively the "Section 25 Arrangements") for the period commencing March 1, 1999 (hereinafter "Phase II"). The modifications to Section 25 of the Tariff (Original Sheet No. 88) are set forth in Exhibit E attached hereto. The language of new Section 25B is set forth in Exhibit E beginning at Original Tariff Sheet No. 92. The agreement of the Parties with respect to Phase II is set forth below:

(a) Section 25 Arrangements, as defined above, shall continue in effect until they expire at 11:59 p.m. on February 28, 2001. Billing under the Section 25 Arrangements shall continue for service rendered through February 28, 2001. The entities receiving Phase I Credits pursuant to the terms of this Settlement Agreement as identified in subparagraph 4(a) of this Section G of the Settlement Agreement, so long as they remain RNS Transmission Customers under the Tariff, shall receive a credit to their NEPOOL transmission bills equal to the amounts they are assessed under the Section 25 Arrangements over the period March 1, 1999 through February 28, 2001 (the "Phase II Credit"). Revisions to Original Sheet Nos. 92 of the NEPOOL Tariff setting forth this agreement are contained in Exhibit E attached hereto. Revisions to the Restated NEPOOL Agreement reflecting discontinuation of credits for Section 25 Arrangements (as defined above) are contained in Exhibit I attached hereto. All LV PTF charges assessed under the Restated NEPOOL Agreement to Transmission Customers receiving network service under both the Tariff and an applicable Local Network Service Tariff shall be terminated as of March 1, 1999.

(b) The Phase II Credit shall be funded by an uplift charge over the two year period March 1, 1999 through February 28, 2001 (the "Phase II Uplift"). The Phase II Uplift shall be paid monthly by all RNS and Internal Point-to-Point Transmission Customers under the NEPOOL Tariff in accordance with NEPOOL's normal billing procedures, allocated based on load ratio with the following exceptions and limitations:

(i) VELCO and CMP shall be exempted from paying the Phase II Uplift.

(ii) BHE's monthly responsibility for the Phase II Uplift shall be based on 50 MW of load.

(iii) ComElec's monthly responsibility for the Phase II Uplift shall be based on 50% of its actual Network Load (excluding the load for Nantucket) and Internal Point-to-Point reservation, if any.

(iv) Montaup's monthly responsibility for the Phase II Uplift shall be based on 50% of its actual Network Load and Internal Point-to-Point reservation, if any.

The total amount of the Phase II Uplift not being paid by VELCO, CMP, BHE, ComElec and Montaup , as set forth above, shall be borne by the remaining RNS and Internal Point-to-Point Transmission Customers, in accordance with the formula provided in the amended Tariff pages attached hereto.

(5) All issues as to Excepted Transactions listed in Attachment G-1 to the NEPOOL Tariff are resolved either by the terms of this Settlement Agreement, including certain side agreements set forth in Exhibit F attached hereto, or by the terms of the settlement between NU and the NU TDUs. If this Settlement Agreement or the NU-NU TDU Settlement Offer is silent with respect to a contract listed in Attachment G-1, that contract will remain in effect according to its terms.

(6) As of March 1, 1999, the remedies for Excepted Transactions agreed upon in this Settlement Agreement, together with previously implemented credits and refunds shall constitute full compliance with the Commission's April 20, 1998 Order, 83 FERC at 61,241-42.

H. Resolution of Return on Equity Issues. To resolve Return on Equity ("ROE") issues raised in the captioned proceedings, the Parties agree as follows:

(1) The table below sets forth the allowed ROE applicable to service under the NEPOOL Tariff for each of the Transmission Providers identified below for the period March 1, 1997 through May 31, 2000:

Bangor Hydro-Electric	11.50%
BECO	10.65%
CMP	11.00%
ComElec	10.75%
Montaup	11.22% (through May 31, 1999) 10.65% (beginning June 1, 1999)
NEP	10.65%
UI	11.5% (through May 31, 1999) 10.75% (beginning June 1, 1999)
VELCO	11.50%
NU	11.75%

The Parties agree not to seek changes, effective prior to June 1, 2000, to the NEPOOL Tariff ROE under Sections 205 or 206 of the Federal Power Act. This Settlement Agreement does not affect the ROE of any NEPOOL Participant that is not listed in the table above.

(2) On and after June 1, 2000, the allowed ROE under the NEPOOL Tariff for each Transmission Provider identified above shall be the ROE stated above, unless a Transmission Provider, after December 31, 1999, has filed an amendment to its cost of service under its LNS Tariff, and the Commission has made the new LNS Tariff rate effective prior to the next adjustment in the NEPOOL ATRR in June of each year. If a Transmission Provider files a post-December 31, 1999 amendment to its cost of service under its LNS Tariff, the ROE used to

determine ATRR shall be the ROE specified in the LNS Tariff filed by the Transmission Provider most recently before such determination. If the ROE in that LNS Tariff has been accepted by the Commission subject to refund, the ATRR for the period commencing June 1 of the year at issue shall be recalculated to reflect the ROE ultimately determined to be just and reasonable by the Commission in the proceeding involving the applicable LNS Tariff filing (the agreement does not preclude any argument that a return on equity established pursuant to Section 206 must be applied prospectively only). Any surcharges and refunds resulting from this adjustment shall be with interest at the Commission's standard rate, as set forth in 18 C.F.R. Section 35.19a.

(3) (i) Except as provided in subparagraph 3(ii) below, nothing in this Settlement Agreement shall affect the ROE of any Transmission Provider under its applicable LNS Tariff. Neither Staff nor any Party may refer to, or use, the resolution of appropriate ROE's herein in any other proceeding, such as Transmission Providers' LNS Tariff filings. (ii) Montaup intends that the April 1, 1999 letter agreement between Montaup and Commission Trial Staff, regarding Montaup's LNS ROE negotiations shall have full force and effect, and shall be considered a part of the overall settlement in this proceeding.

(4) To implement this provision of the Settlement Agreement, Section II.A.2(a)(iii) of Attachment 1 to the NEPOOL-Staff Stipulation shall be modified to read in accordance with the language contained in Exhibit H attached hereto.

I. Agreement to Support Revisions to Tariff and Restated NEPOOL Agreement Required to Implement the Terms of this Settlement Agreement. To implement the terms of this

Settlement Agreement, including the terms of the NEPOOL-Staff Stipulation and the NEPOOL-MMWEC Letter Agreement, certain changes to the NEPOOL Tariff and Restated NEPOOL Agreement are required. The Parties agree to support the changes to the NEPOOL Tariff set forth in the NEPOOL-Staff Stipulation and in Exhibits B, D, E and H (and Exhibit J, as applicable and in accordance with the provisions of Section G(2)(b) of this Settlement Agreement) attached hereto, and to the Restated NEPOOL Agreement set forth in Exhibit I attached hereto.

K. Purpose and Benefits of the Settlement Agreement. The Parties have entered into this Settlement Agreement to amicably resolve all of their disputes in these proceedings and to avoid the risks, burdens and expenses of litigating those disputes. Nothing in this Settlement Agreement is intended by the Parties to reflect an admission regarding the merits of their own cases or arguments or of another signatory's case or argument on any of the settled issues. The submission of this Settlement Agreement and the concurrence in, or failure to comment on, the described settlement shall not be deemed to constitute an admission by any Party that any allegations or contentions in this proceeding are true or valid or that any Party has acted consistent with, or contrary to, contract provisions, the Federal Power Act or any other federal or state law or regulation.

L. Withdrawal of Certain Pending Requests for Relief from the April 20, 1998

Order. Various of the Parties to this Settlement Agreement have filed requests for rehearing, reconsideration, clarification, modification or any other relief from the Commission's April 20 Order (hereafter a "Request for Relief"), as identified in the Commission's June 2, 1998 Order Granting Rehearing for Further Consideration in the captioned proceedings. Upon approval of this Settlement Agreement, including but not limited to the NEPOOL-Staff Stipulation, NEPOOL-BRT Stipulation, NEPOOL-MMWEC Letter Agreement, and NU-NU TDU Settlement Offer, any such Request for Relief that has been filed by a Party is deemed withdrawn or mooted, except as specifically provided below:

1. All issues raised in Boston Edison's Request for Rehearing (dated May 20, 1998).

2. Part II of NU's Request for Rehearing (dated May 20, 1998) to the extent it requests clarification that the Commission intended in its April 20 Order that (i) the ISO must reserve some tie line capacity for reliability purposes and that the amount and duration of such retained capacity is subject to the ISO's judgment, and (ii) Transmission Providers have the right to charge lost opportunity costs when the ties are fully utilized as provided in Northeast Utilities Service Company, 83 FERC ¶61,123 (1998).

3. All issues raised by USGen in its May 20, 1998 Request for Clarification, or

Alternatively Rehearing, of U.S. Generating Company, MASSPOWER and Pittsfield Generating Company, LP, except for the issues raised in the paragraph on page 6 of that request labeled "Treatment of Excepted Transactions."

4. All issues raised in the Request for Rehearing of Vermont Electric Power Company (dated May 20, 1998).

M. Confidentiality. The discussions among the Parties related to the terms of this Settlement Agreement took place within the context of formal and informal global and bilateral settlement discussions concerning matters covered herein. The Parties, and Staff, agree that such discussions are confidential in accordance with the applicable sections of the Commission Rules of Practice and Procedure and the Federal Rules of Evidence. The Parties, and Staff, also agree to maintain the confidentiality of those discussions in accordance with those rules.

N. Miscellaneous Provisions. (1) The Parties, and Staff, shall support fully the Settlement Agreement before the Commission and shall support a request to the Commission to permit implementation of the Settlement Agreement as of March 1, 1999 pending final Commission approval of the Agreement.

(2) The Commission's approval of this Settlement Agreement shall not constitute approval of or precedent regarding any principle or issue in this proceeding, including any claim

by any Party as to the lawfulness of requiring retrospective refunds.

(3) This Settlement Agreement is expressly conditioned upon the Commission's acceptance of the terms and conditions hereof, without modifications or omission. This Settlement Agreement is submitted on the understanding and condition that, if the Commission does not by order approve this Settlement Agreement in its entirety, this Settlement Agreement and all related documents in this proceeding shall be deemed of no effect and shall not constitute part of the record in any proceeding or be used for any other purpose. In such event, the terms (if and as finally approved by the Commission) of the NEPOOL-Staff Stipulation, NEPOOL-BRT Stipulation, NEPOOL-MMWEC Letter Agreement, and/or NU - NU TDU Settlement Offer shall continue in full force and effect.

(4) Capitalized terms used in this Settlement Agreement that are not defined herein shall have the meanings ascribed to them in the Restated NEPOOL Agreement or NEPOOL Tariff, as applicable.

NEPOOL Dockets OA97-237-000, et al.

THE NEW ENGLAND POWER POOL
EXECUTIVE COMMITTEE

By: ____________________
David T. Doot, Esq.
Its: Counsel, Duly Authorized
Dated: April 5, 1999

BANGOR HYDRO-ELECTRIC COMPANY

By: ____________________
Carroll R. Lee
Its: Senior Vice President and Chief Operating Officer, Duly Authorized
Dated: ____________________

BOSTON EDISON COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

BRAINTREE ELECTRIC LIGHT DEPARTMENT
READING MUNICIPAL LIGHT DEPARTMENT
TAUNTON MUNICIPAL LIGHTING PLANT

By: ____________________
John P. Coyle, Esq.
Their: Counsel, Duly Authorized
Dated: ____________________

THE NEW ENGLAND POWER POOL
EXECUTIVE COMMITEE

By. ________________
David T. Doot, Esq.
Its· Counsel, Duly Authorized
Dated: ________________

BANGOR HYDRO-ELECTRIC COMPANY

By· ________________
Carroll R. Lee
Its· Senior Vice President and Chief Operating Officer, Duly Authorized
Dated. 4/1/99

BOSTON EDISON COMPANY

By. ________________
Its. ________________, Duly Authorized
Dated: ________________

BRAINTREE ELECTRIC LIGHT DEPARTMENT
READING MUNICIPAL LIGHT DEPARTMENT
TAUNTON MUNICIPAL LIGHTING PLANT

By. ________________
John P Coyle, Esq
Their· Counsel, Duly Authorized
Dated· ________________

CENTRAL MAINE POWER COMPANY

By· ________________
John R. Matson, III, Esq

APR 5 '99 PM 12:55

APR 5 '99 PM 1:12

THE NEW ENGLAND POWER POOL
EXECUTIVE COMMITEE

By. ____________________
David T Doot, Esq.
Its. Counsel. Duly Authorized
Dated ____________________

BANGOR HYDRO-ELECTRIC COMPANY

By ____________________
Carroll R. Lee
Its: Senior Vice President and Chief Operating Officer, Duly Authorized
Dated: ____________________

BOSTON EDISON COMPANY

By ____________________
Its. Senior Vice President, Duly Authorized
Dated 4/2/99

BRAINTREE ELECTRIC LIGHT DEPARTMENT
READING MUNICIPAL LIGHT DEPARTMENT
TAUNTON MUNICIPAL LIGHTING PLANT

By: ____________________
John P. Coyle, Esq.
Their. Counsel, Duly Authorized
Dated ____________________

HARTO2-201 18231.0
88327-10120
April 1 1999 6 07 pm

THE NEW ENGLAND POWER POOL
EXECUTIVE COMMITEE

By ____________________
David T. Doot, Esq
Its. Counsel, Duly Authorized
Dated: ____________________

BANGOR HYDRO-ELECTRIC COMPANY

By: ____________________
Carroll R. Lee
Its. Senior Vice President and Chief Operating Officer, Duly Authorized
Dated: ____________________

BOSTON EDISON COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated. ____________________

BRAINTREE ELECTRIC LIGHT DEPARTMENT
READING MUNICIPAL LIGHT DEPARTMENT
TAUNTON MUNICIPAL LIGHTING PLANT

By. ____________________
John P. Coyle, Esq
Their Counsel, Duly Authorized
Dated: APRIL 2, 1999

HARTO2-20130225-?
66227-10120
April 1, 1999 6 07 pm

CENTRAL MAINE POWER COMPANY

By: [signature]
Frederick Woodruff
Its: Managing Director, Duly Authorized
Dated: April 4 1999

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

By: ________________
Hans G. Huessey, Esq.
Its: Corporate Counsel, Duly Authorized
Dated: ________________

COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
CANAL ELECTRIC COMPANY

By: ________________

Its: ________________, Duly Authorized
Dated: ________________

THE CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE
CHICOPEE MUNICIPAL LIGHTING PLANT OF THE CITY OF CHICOPEE, MASSACHUSETTS
WESTFIELD GAS AND ELECTRIC LIGHT DEPARTMENT OF THE CITY OF WESTFIELD, MASSACHUSETTS
SOUTH HADLEY ELECTRIC LIGHT DEPARTMENT

By: ________________
Their: ________________, Duly Authorized
Dated: ________________

CENTRAL MAINE POWER COMPANY

By: ________________
John R. Matson, III, Esq.
Its: Counsel, Duly Authorized
Dated: ________________

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

By: ________________
Hans G. Huessey, Esq.
Its: Corporate Counsel, Duly Authorized
Dated: 4/2/99

COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
CANAL ELECTRIC COMPANY

By: ________________

Its: ________________, Duly Authorized
Dated: ________________

THE CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE
CHICOPEE MUNICIPAL LIGHTING PLANT OF THE CITY OF
CHICOPEE, MASSACHUSETTS
WESTFIELD GAS AND ELECTRIC LIGHT DEPARTMENT OF THE CITY OF
WESTFIELD, MASSACHUSETTS
SOUTH HADLEY ELECTRIC LIGHT DEPARTMENT

By: ________________
Their: ________________, Duly Authorized
Dated: ________________

CENTRAL MAINE POWER COMPANY

By: ____________________
John R. Manson, III, Esq.
Its: Counsel, Duly Authorized
Dated: ____________________

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

By: ____________________
Hans G. Huessey, Esq.
Its: Corporate Counsel, Duly Authorized
Dated: ____________________

COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
CANAL ELECTRIC COMPANY

By: Deborah A. McLaughlin
D. A. McLaughlin
Their: ~~Its:~~ President, Duly Authorized
Dated: April 2, 1999

THE CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE
CHICOPEE MUNICIPAL LIGHTING PLANT OF THE CITY OF CHICOPEE, MASSACHUSETTS
WESTFIELD GAS AND ELECTRIC LIGHT DEPARTMENT OF THE CITY OF WESTFIELD, MASSACHUSETTS
SOUTH HADLEY ELECTRIC LIGHT DEPARTMENT

By: ____________________
Their: ____________________, Duly Authorized
Dated: ____________________

CENTRAL MAINE POWER COMPANY

By ____________________
John R. Matson, III. Esq.
Its Counsel, Duly Authorized
Dated ____________________

CENTRAL VERMONT PUBLIC SERVICE CORPORATION

By: ____________________
Hans G. Huessey, Esq.
Its Corporate Counsel, Duly Authorized
Dated ____________________

COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY
CANAL ELECTRIC COMPANY

By ____________________

Its ____________________, Duly Authorized
Dated ____________________

THE CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE
CHICOPEE MUNICIPAL LIGHTING PLANT OF THE CITY OF CHICOPEE, MASSACHUSETTS
WESTFIELD GAS AND ELECTRIC LIGHT DEPARTMENT OF THE CITY OF WESTFIELD, MASSACHUSETTS
SOUTH HADLEY ELECTRIC LIGHT DEPARTMENT

By ____________________
Their Counsel, Duly Authorized
Dated April 2, 1999

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

By: ____________________
David K. Foote
Its: Senior Vice President, Duly Authorized
Dated: April 2, 1999

ISO NEW ENGLAND INC.

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

By: ____________________
George E. Leary
Its: General Manager, Duly Authorized
Dated: ____________________

MONTAUP ELECTRIC COMPANY
EASTERN UTILITIES ASSOCIATES OPERATING COMPANIES

By: ____________________
Kevin A. Kirby
Their: Vice President, Montaup Electric Company, Duly Authorized
Dated: ____________________

NEW ENGLAND POWER COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

By: ________________
David K. Foote
Its: ________________, Duly Authorized
Dated: ________________

ISO NEW ENGLAND INC.

PAUL SHORTLEY
By: Paul Shortley
Its: Director System Operations and Reliability, Duly Authorized
Dated: 4/5/99

THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

By: ________________
George E. Leary
Its: General Manager, Duly Authorized
Dated: ________________

MONTAUP ELECTRIC COMPANY
EASTERN UTILITIES ASSOCIATES OPERATING COMPANIES

By: ________________
Kevin A. Kirby
Their: Vice President, Montaup Electric Company, Duly Authorized
Dated: ________________

NEW ENGLAND POWER COMPANY

By: ________________
Its: ________________, Duly Authorized
Dated: ________________

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

By: ____________________
David K. Foote
Its: ____________________, Duly Authorized
Dated: ____________________

ISO NEW ENGLAND INC.

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

By: G E Leary
George E. Leary
Its: General Manager, Duly Authorized
Dated: 04/05/99

MONTAUP ELECTRIC COMPANY
EASTERN UTILITIES ASSOCIATES OPERATING COMPANIES

By: ____________________
Kevin A. Kirby
Their: Vice President, Montaup Electric Company, Duly Authorized
Dated: ____________________

NEW ENGLAND POWER COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

By: ____________________
David K. Foote
Its: ____________________, Duly Authorized
Dated: ____________________

ISO NEW ENGLAND INC.

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

By: ____________________
George E. Leary
Its: General Manager, Duly Authorized
Dated: ____________________

MONTAUP ELECTRIC COMPANY
EASTERN UTILITIES ASSOCIATES OPERATING COMPANIES

By: Kevin A Kirby
Kevin A. Kirby
Their: Vice President, Montaup Electric Company, Duly Authorized
Dated: April 5, 1999

NEW ENGLAND POWER COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

FITCHBURG GAS AND ELECTRIC LIGHT COMPANY

By: ____________________
David K. Foote
Its: ____________________, Duly Authorized
Dated: ____________________

ISO NEW ENGLAND INC.

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE MASSACHUSETTS MUNICIPAL WHOLESALE ELECTRIC COMPANY

By: ____________________
George E. Leary
Its: General Manager, Duly Authorized
Dated: ____________________

MONTAUP ELECTRIC COMPANY
EASTERN UTILITIES ASSOCIATES OPERATING COMPANIES

By: ____________________
Kevin A. Kirby
Their: Vice President, Montaup Electric Company, Duly Authorized
Dated: ____________________

NEW ENGLAND POWER COMPANY

By: Masheed H. Rosenqvist
Its: Vice President, Duly Authorized
Dated: 4/2/99

NORTHEAST UTILITIES SERVICE COMPANY
ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY, WESTERN MASSACHUSETTS ELECTRIC COMPANY, HOLYOKE WATER POWER COMPANY, AND PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By David H. Boguslawski
Their: Vice President, Duly Authorized
Dated April 2, 1999

SITHE NEW ENGLAND HOLDINGS, LLC

By. ____________________
Its: ____________________, Duly Authorized
Dated. ____________________

THE UNITED ILLUMINATING COMPANY

By ____________________
Its. ____________________, Duly Authorized
Dated: ____________________

UNITIL POWER CORP.

By ____________________
David K. Foote
Its: Senior Vice President, Duly Authorized
Dated. ____________________

US GENERATING COMPANY
MASSPOWER
PITTSFIELD GENERATING CO., LP

By. ____________________
George Grunbeck, Esq
Their ____________________, Duly Authorized
Dated. ____________________

HART01-[illegible]
[illegible]
April 1, 1999 [illegible]

NORTHEAST UTILITIES SERVICE COMPANY
ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY,
WESTERN MASSACHUSETTS ELECTRIC COMPANY, HOLYOKE
WATER POWER COMPANY, AND PUBLIC SERVICE COMPANY
OF NEW HAMPSHIRE

By. ____________________

Their. ____________________, Duly Authorized

Dated. ____________________

SITHE NEW ENGLAND HOLDINGS, LLC

By: [signature]

Its: Vice President, Duly Authorized

Dated. 4/5/99

THE UNITED ILLUMINATING COMPANY

By: ____________________

Its. ____________________, Duly Authorized

Dated: ____________________

UNITIL POWER CORP.

By. ____________________

David K. Foote

Its. Senior Vice President, Duly Authorized

Dated. ____________________

US GENERATING COMPANY
MASSPOWER
PITTSFIELD GENERATING CO., LP

By: ____________________

George Grunbeck, Esq

Their ____________________, Duly Authorized

Dated: ____________________

Privileged and Confidential - Draft Settlement Agreement
Attorney Work-Product; Prepared for Litigation

NORTHEAST UTILITIES SERVICE COMPANY
ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY,
WESTERN MASSACHUSETTS ELECTRIC COMPANY, HOLYOKE
WATER POWER COMPANY, AND PUBLIC SERVICE COMPANY
OF NEW HAMPSHIRE

By: ____________________
Their: ____________________, Duly Authorized
Dated: ____________________

SITHE NEW ENGLAND HOLDINGS, LLC

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE UNITED ILLUMINATING COMPANY

By: Stephen F. Goldschmidt
Its: Stephen F. Goldschmidt, Duly Authorized
Dated: 4/5/99

UNITIL POWER CORP.

By: ____________________
David K. Foote
Its: Senior Vice President, Duly Authorized
Dated: ____________________

US GENERATING COMPANY
MASSPOWER
PITTSFIELD GENERATING CO., LP

By: ____________________
George Grunbeck, Esq
Their: ____________________, Duly Authorized
Dated: ____________________

HART02-20159225-9
64227-10120
April 5, 1999 10:55 am

NORTHEAST UTILITIES SERVICE COMPANY
ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY, WESTERN MASSACHUSETTS ELECTRIC COMPANY, HOLYOKE WATER POWER COMPANY, AND PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

By: ____________________
Their: ____________________, Duly Authorized
Dated: ____________________

SITHE NEW ENGLAND HOLDINGS, LLC

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

THE UNITED ILLUMINATING COMPANY

By: ____________________
Its: ____________________, Duly Authorized
Dated: ____________________

UNITIL POWER CORP.

By: David K. Foote
David K. Foote
Its: Senior Vice President, Duly Authorized
Dated: April 2, 1999

US GENERATING COMPANY
MASSPOWER
PITTSFIELD GENERATING CO., LP

By: ____________________
George Grunbeck, Esq
Their: ____________________, Duly Authorized
Dated: ____________________

NORTHEAST UTILITIES SERVICE COMPANY
ON BEHALF OF THE CONNECTICUT LIGHT AND POWER COMPANY,
WESTERN MASSACHUSETTS ELECTRIC COMPANY, HOLYOKE
WATER POWER COMPANY, AND PUBLIC SERVICE COMPANY
OF NEW HAMPSHIRE

By: ________________
Their: ________________, Duly Authorized
Dated: ________________

SITHE NEW ENGLAND HOLDINGS, LLC

By: ________________
Its: ________________, Duly Authorized
Dated: ________________

THE UNITED ILLUMINATING COMPANY

By: ________________
Its: ________________, Duly Authorized
Dated: ________________

UNITIL POWER CORP.

By: ________________
David K. Foote
Its: Senior Vice President, Duly Authorized
Dated: ________________

US GENERATING COMPANY
MASSPOWER, by MASSPOWER, Inc., a general partner
PITTSFIELD GENERATING CO., LP, by Altresco, Inc., a general partner

By: George Grunbeck
George Grunbeck, Esq
Their: ________________, Duly Authorized
Dated: ________________

VERMONT ELECTRIC POWER COMPANY

By: Gerald F. Sprague

Its: CFO, Duly Authorized

Dated: 4/7/1999

NEPOOL Dockets OA97-237-000, et al.
April 5, 1999 Settlement Agreement

EXHIBIT A

Joint Stipulation Between New England Power Pool and
Commission Trial Staff
Regarding Certain Issues Set for Hearing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool	)	Dockets Nos. OA97-237-000, ER97-1079-
	)	000, ER97-3574-000, OA97-608-000,
	)	ER97-4421-000 and ER98-499-000

JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF REGARDING CERTAIN ISSUES SET FOR HEARING (February 12, 1999)

To: The Honorable Lawrence J. Brenner
Presiding Administrative Law Judge

This joint stipulation ("Stipulation") is entered into by and between the New England Power Pool ("NEPOOL") and the Commission Trial Staff ("Staff") to resolve by agreement certain disputes between them with respect to certain issues set for hearing in the above-captioned docket by the Commission in its April 20, 1998 Order. The parties hereby stipulate as follows:

1. General Stipulation. (a) Except to the extent otherwise specifically stated below, and conditioned upon the agreements reflected in this Stipulation, Staff hereby withdraws the objections set forth in its pre-filed testimony in the captioned dockets concerning the justness and reasonableness of the terms of Attachment F to the NEPOOL Tariff, as set forth in the attached document entitled: "Attachment 1: Substance of Draft Rule for Calculating Annual Transmission Revenue Requirements" ("Proposed Attachment F Implementation Rule"), and to Schedule 1 of the NEPOOL Tariff as set forth in the attached document entitled: "Attachment 2:

Substance of Draft Rule for Calculating Charges under Schedule 1- Scheduling, System Control and Dispatch Service" ("Proposed Schedule 1 Implementation Rule"), and of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Open Access Transmission Tariff (the "NEPOOL Tariff"), as most currently filed by NEPOOL, as of the date of the execution of this Stipulation. The parties to this Stipulation, except to the extent otherwise specifically stated below, agree that the proposed rules in Attachments 1 and 2, hereto, and the Ancillary Service Schedules identified above, are just and reasonable and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in the above-captioned dockets.

2. Agreement Regarding Pre-Filed Testimony and Exhibits. To implement the terms of this Stipulation, Staff shall not offer into the hearing record its pre-filed testimony and exhibits, submitted with respect to the hearings currently scheduled to commence on March 2, 1999 in these proceedings, which are inconsistent with the terms set forth in this Stipulation. The parties shall agree on or before February 23, 1999 as to which portions of their pre-filed testimony and exhibits each will offer into the record. However, each party may offer other portions of their pre-filed testimony and exhibits into the record to the extent necessary to support this Stipulation based on developments occurring after execution of this Stipulation.

3. Informational Filings. NEPOOL shall make an annual informational filing, on or before July 31 of each year, showing the Pool PTF Rate [1] and Schedule 1 rate surcharge in effect for the period beginning June 1 of that year through May 31 of the subsequent year. That informational filing will provide information in detail that is substantially comparable to the NEPOOL submissions in the captioned dockets, dated June 4, 1998, and June 23, 1998. Further, the informational filing with respect to the determination of the Pool PTF rate will include a breakdown by Participant and amount of the change in PTF investment during the prior year and the PTF retirements or additions causing such change, including beginning- and end-of-year PTF balances (although the beginning-of-year PTF balance is not used in the formula itself), and any additions to PTF, retirements of PTF, and reclassifications of PTF during the year for each Transmission Provider. If there are any corrections made to the information reflected in the informational filing after it has been submitted, NEPOOL will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, NEPOOL shall make available to NEPOOL Participants and any other interested persons a draft of the proposed filing for review and comment.

4. Refunds and Surcharges. NEPOOL shall make refunds and surcharges as appropriate to reflect the terms set forth in this Stipulation. Refunds and surcharges will be made to all parties to whom they are due, including but not limited to the intervenors in these

---

[1] Capitalized terms used but not defined in this proposal are intended to have the same meanings given to such terms in Section 1 of the Restated NEPOOL Agreement or Section 1 of the NEPOOL Open Access Transmission Tariff.

proceedings. NEPOOL shall make adjustments to the charges calculated under the formula rate as reflected in Attachment F to incorporate the adjustments (including correction of the errors) identified by Staff in its pre-filed testimony at Exhibit S-1 p. 13, line 9 through p. 15, line 3, p. 31, lines 3 through 8, and line 22 through p. 32, line 4, p. 33, lines 7 through 18; Exhibit S-2, Exhibit S-3; Exhibit S-4; Exhibit S-6; Exhibit 18; p. 18, line 22 through p. 20, line 3; Exhibit S-20; Exhibit S-21; and Exhibit S-22, relating to charges under Attachment F, with the adjustments (including corrections) retroactive to March 1, 1997, as appropriate. NEPOOL shall also make any refunds or surcharges as appropriate to reflect any difference between (a) the return on equity for any Transmission Provider reflected in the Attachment F rates calculated and charged for service under the NEPOOL Tariff since March 1, 1997, and (b) the return on equity ultimately determined to be just and reasonable by the Commission in this proceeding, including, if the Commission approves NEPOOL's proposal to link the return on equity in Attachment F of the NEPOOL Tariff to that on file in each Transmission Provider's LNS Tariff, the return on equity ultimately determined to be just and reasonable by the Commission in the proceeding involving the applicable LNS Tariff filing.[2] Unless otherwise specifically provided, all refunds and surcharges required by this Stipulation shall be with interest at the Commission's standard rate, as set forth in 18 C.F.R. Section 35.19a.

---

[2]This agreement does not preclude any argument that a return on equity established pursuant to Section 206 must be applied prospectively only.

5. Compliance Filing. Upon a final Commission order addressing the issues that are the subject of these proceedings, including but not limited to the issues which are the subject of this Stipulation, NEPOOL shall make, in accordance with the applicable Commission Rules of Practice and Procedure, a compliance filing that implements the terms of this Stipulation to the extent not otherwise changed by Commission order. As part of the compliance filing described in this Section, NEPOOL shall include Exhibit NPL-12, which is that portion of the current NABS Procedure No. 12 used to determine transmission line, terminal facilities and right of way PTF investment.

6. Independent Audits. The System Operator shall independently audit the charges in effect for the period June 1997 through May 2000, or direct that an audit[s] be conducted under its supervision by an independent third party. Such audit[s] shall verify, through such sampling as appropriate, that Transmission Providers are correctly accounting for PTF investment in accordance with the applicable NEPOOL rules for determining PTF investment. The results of any such audit[s] shall be filed with the Commission as an informational filing, and the charges recalculated to correct any errors identified in such audit, with refunds and surcharges, as appropriate, for any amounts previously over- or under-charged due to such errors. To the extent that the costs of the independent audit[s] are not reflected in a prior or currently existing ISO-NE budget, such costs shall be recovered as a surcharge under the NEPOOL Tariff, derived and charged in a manner comparable to the charge for post-1996 PTF. All claims raised with respect to an audit must be asserted within two years of the date of the

informational filing. The System Operator shall have discretion to conduct an independent audit of the charges in effect, on and after, June 1, 2000, or direct that such an audit be conducted under its supervision by an independent third party.

7. Recalculation of Charges Under Formula Rates. Parties challenging the calculations reflected in the informational filing described in Section 3 above will bear the burden under the Federal Power Act of demonstrating that such calculations are unjust or unreasonable. The filing of the informational filing does not reopen the Attachment F formula rate for review, but rather is contestable only with respect to the accuracy of the information it contains. Any changes by NEPOOL to the formula itself will be made in a Section 205 filing.

8. Changes to the Proposed Rule for Implementing Attachment F. As part of the compliance filing described in Section 5 above, NEPOOL shall file the Proposed Rule for Implementing Attachment F, contained in Attachment 1 hereto, with such changes, if any, as may be required by the Commission and/or any court of competent jurisdiction reviewing these proceedings. NEPOOL shall not implement any changes to the rule without first filing the changed rule with the Commission pursuant to Section 205 of the Federal Power Act.

9. As to Return on Equity Issues. Except as contained in Section 4 above, NEPOOL and Staff have not reached any agreement with respect to the provisions of Section A.2(a)(iii) of Attachment 1 hereto, concerning the return on equity component of Attachment F to the NEPOOL Tariff. Nothing in this Stipulation precludes NEPOOL or Staff from asserting any argument with respect to this issue.

10. As to PTF Support Expenses. Effective March 1, 1997, the load flow distribution set forth in Section D.4 of Attachment A to the Restated NEPOOL Agreement shall be modified, as follows:

> Each Participant shall have assigned to it the MW-miles associated with each PTF facility for which it has full ownership and for which there are no arrangements in effect by which other Participants support the facility. For facilities that are jointly owned and/or supported, each Participant shall be assigned MW-miles in proportion to the percentage of its ownership of jointly-owned facilities and/or the percentage of its support for facilities that are jointly supported to the extent such support payments are included in the determination of Annual Transmission Revenue Requirements.

Effective also March 1, 1997, the load flow distribution of RNS and Internal Point-to-Point Service revenues will be implemented in accordance with Attachment A to the Restated NEPOOL Agreement, as modified above, so that the load flows over jointly supported facilities are allocated to Transmission Providers and other Participants in proportion to the cost responsibility for those jointly supported facilities included in the Attachment F calculation for each Transmission Provider or other Participant. As part of the compliance filing discussed in Section 5 above, NEPOOL shall calculate the load flow distribution as set forth in this Section as if it had been effective on March 1, 1997, and make refunds and surcharges, with interest, as appropriate. For billing purposes, NEPOOL will implement the load flow distribution set forth above prospectively effective with the March 1999 billing cycle.

11. As to Ancillary Service Schedule 1: Scheduling, System Control and Dispatch Service. (a) Changes to the Rule. As part of the compliance filing referred to in Section 5 above, NEPOOL shall file with the Commission the Proposed Rule for Implementing Schedule 1,

contained in Attachment 2 hereto, with such changes, if any, as may be required by the Commission and/or any court of competent jurisdiction reviewing these proceedings. NEPOOL shall not implement any changes to the rule without first filing the changed rule with the Commission, pursuant to Section 205 of the Federal Power Act. (b) Refund and Surcharge Obligations. No adjustments to the surcharges under Schedule 1, as reflected in the informational filings submitted prior to February 1, 1999, shall be made or required. The amounts associated with the SCADA and Maine Satellite Revenue Requirements shall not change from those reflected in the calculation of the current Schedule 1 surcharge under the NEPOOL Tariff. No different amounts associated with the SCADA and Maine Satellite Revenue Requirements will be reflected in Schedule 1 rates until a Section 205 rate schedule filing is made setting forth how those costs will be determined.

12. As to Ancillary Service Schedule 2: Reactive Supply and Voltage Control from Generation Sources Service. The parties agree that any generator which supplies reactive power and voltage control services is entitled to be compensated for providing such services and, pending a proposal for a non-zero "CC" charge, compensation will be provided to such generators under the LOC and SCL variables of Schedule 2. There is no agreement, however, as to whether it is just and reasonable to collect simultaneously cost-based charges under the "CC" variable of Schedule 2 and market-based charges under the "LOC" and "SCL" variables of the related formula, or whether generators are already being compensated other than under Schedule

2 of the NEPOOL Tariff, or obligated under other arrangements, for providing reactive power and voltage control services.

The parties agree that no charges will be assessed under the "CC" variable for VAR support under Schedule 2 of the NEPOOL Tariff until NEPOOL makes a Section 205 rate schedule filing proposing such a non-zero "CC" charge or the Commission issues an order permitting a non-zero "CC" charge. If NEPOOL makes such filing for collection of charges under the "CC" variable of Schedule 2, NEPOOL will bear the burden under the Federal Power Act of demonstrating that the inclusion of that variable simultaneously with the "LOC" and "SCL" components in the Schedule 2 formula rate is just and reasonable, as well as justifying the amount determined for the charge. Nothing in this Stipulation shall preclude any of the parties from making any arguments, or taking any position, with respect to the inclusion or exclusion of a non-zero "CC" charge from Schedule 2 at such time as a non-zero "CC" charge is sought.

The parties further agree that charges for reactive power and voltage control services from generation resources provided in connection with transmission service under Schedule 2 of the NEPOOL Tariff or LNS Tariffs will be assessed solely under the NEPOOL Tariff on and after the Second Effective Date. On or before the date of the compliance filing identified in Section 5 above, each Transmission Provider shall make an appropriate compliance filing with respect to its LNS Tariff reflecting this provision of the Stipulation.

13. <u>As to Ancillary Service Schedules 3 (Automatic Generation Control) and 5, 6 and 7 (Operating Reserves)</u>. (a) These ancillary services shall be provided in accordance with the

applicable market rules on file with the Commission, which, together with the applicable Operating Procedures for such services, shall be treated as supplements to the Tariff Schedules and amendments to these supplements made by NEPOOL will be made by a Section 205 filing. (b) ISO-NE will begin posting on its Internet home page for public download and/or review a projection of the hourly requirements for these ancillary services for the following week, updated daily for the next seven days, and as promptly as practical to reflect unforeseen changes in system conditions, and will include in the NEPOOL OASIS a hot link to this section of its home page, within 30 days of the filing of this Stipulation. (c) Automatic Generation Control and Operating Reserves necessary to operate within the NEPOOL control area will be provided through the NEPOOL Tariff on and after the Second Effective Date, with cost recovery for such service provided exclusively under the NEPOOL Tariff.

14. Certain Further Agreements Regarding Attachment F and Ancillary Service Schedules. In addition to effecting the refunds and surcharges identified in Section 4 above, NEPOOL agrees that it shall hereafter implement Attachment F and Ancillary Service Schedules 1, 3, 5, 6 and 7 in accordance with the detailed implementation rules identified in this Stipulation. To the extent any such detailed implementation rule has not already been filed with the Commission, NEPOOL shall file such rule with the compliance filing identified Section 5 above. Starting on the Second Effective Date, all charges for services under Ancillary Service Schedules 2 through 7 of the NEPOOL Tariff shall be collected solely under the NEPOOL Tariff and no such charges shall be collected under related schedules of the LNS Tariffs of the

Transmission Providers. On or before the date of the compliance filing identified in Section 5 above, each Transmission Provider shall make an appropriate compliance filing with respect to its LNS Tariff reflecting this provision of the Stipulation.

15. As to Excepted Transactions. NEPOOL and Staff have not reached any agreement as to the resolution of the treatment of Excepted Transactions. Nothing in this Stipulation precludes either party from asserting any argument with respect to the treatment of Excepted Transactions, other than those as to which agreement has been reached as set forth above.

16. Purpose and Benefits of Stipulation. The parties have entered into this Stipulation to amicably resolve certain of their differences arising in these proceedings, and for the purposes of avoiding to the extent possible, the burdens and risks of litigating those issues. Nothing in this Stipulation is intended by the parties to reflect any kind of an admission regarding the merits of its own case or of another signatory party's case on any of these issues.

17. Confidentiality. The discussions between the parties related to the agreements set forth in this Stipulation took place within the context of global and bilateral settlement discussions in this matter and the parties agree that such discussions are confidential in accordance with the applicable sections of the Commission Rules of Practice and Procedure and the Federal Rules of Evidence. The parties agree to maintain the confidentiality of those discussions in accordance with those rules.

18. Other Implementation Issues. The parties agree that, with respect to the issues set forth herein as to which they have reached agreement, neither will take a position, in the above captioned proceedings, in these matters contrary to the agreements set forth herein, and neither will assist another party in taking such a position. However, the parties may continue to participate in these proceedings to support this Stipulation and oppose any other party taking a position contrary to the agreements set forth herein.

19. Limitations With Respect to Changing the NEPOOL Agreement or Tariff. Nothing in this Stipulation restricts NEPOOL from changing the Restated NEPOOL Agreement or the NEPOOL Tariff, or any rules referenced herein, provided that such changes are properly authorized in accordance with the provisions of the Restated NEPOOL Agreement and as amended from time to time are filed with the Commission pursuant to Section 205 of the Federal Power Act. The agreements set forth in this Stipulation are solely for the purpose of the above captioned proceedings and nothing in this Stipulation restricts any parties to this Stipulation from taking any position or lawful action in any future proceedings.

18. Other Implementation Issues. The parties agree that, with respect to the issues set forth herein as to which they have reached agreement, neither will take a position, in the above captioned proceedings, in these matters contrary to the agreements set forth herein, and neither will assist another party in taking such a position. However, the parties may continue to participate in these proceedings to support this Stipulation and oppose any other party taking a position contrary to the agreements set forth herein.

19. Limitations With Respect to Changing the NEPOOL Agreement or Tariff. Nothing in this Stipulation restricts NEPOOL from changing the Restated NEPOOL Agreement or the NEPOOL Tariff, or any rules referenced herein, provided that such changes are properly authorized in accordance with the provisions of the Restated NEPOOL Agreement and as amended from time to time are filed with the Commission pursuant to Section 205 of the Federal Power Act. The agreements set forth in this Stipulation are solely for the purpose of the above captioned proceedings and nothing in this Stipulation restricts any parties to this Stipulation from taking any position or lawful action in any future proceedings.

Respectfully submitted,

THE NEW ENGLAND POWER POOL
EXECUTIVE COMMITTEE

By: ______________________
Its Attorney, Duly Authorized
Dated: February 12, 1999

FEDERAL ENERGY REGULATORY COMMISSION
TRIAL STAFF

By: ______________________
Joseph H. Long, Trial Staff Counsel
Dated: February 16, 1999

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 1st day of March, 1999, on behalf of:

Bangor Hydro-Electric Company

By: [signature]

Of: Wright + Talisman, P.C.

Its Duly Authorized: Attorney

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 19th day of Feb., 1999, on behalf of:

Boston Edison Company

By: James H. McGrew
James H. McGrew
Of: Bruder, Gentile & Marcoux, L.L.P.

Its Duly Authorized: Counsel

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 17th day of February, 1999, on behalf of:
U.S. Generating Company, MASSPOWER, and Pittsfield Generating Company, L.P.

By: Larry Eisenstat

Of: Dickstein Shapiro Morin & Oshinsky LLP

Its Duly Authorized: Counsel

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 18th day of February, 1999, on behalf of:

Central Maine Power Company

By: John R. Matson, III John R. Matson, III

Of: Huber Lawrence & Abell

Its Duly Authorized: Attorney

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation

Respectfully submitted on this 22nd day of February, 1999, on behalf of

____

By: David H. Boguslawski

Of: Northeast Utilities Service Company

Its Duly Authorized. Vice President

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 18th day of February 1999, on behalf of:

ISO New England Inc.

By: [signature]

Of: Ballard Spahr Andrews & Ingersoll, L.L.P.

Its Duly Authorized: Attorney

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 18th day of FEBRUARY 1999, on behalf of:

NEW ENGLAND POWER COMPANY

By: [signature] [CARLOS A. GAVILONDO]

Of: NEW ENGLAND POWER SERVICE CO.

Its Duly Authorized: ATTORNEY

03/11/99 14:06 202 208 1219 FERC LITIGATION

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999
JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL
AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 11th day of March, 1999, on behalf of:

Massachusetts Municipal Wholesale Electric Company

By: G. E. Leary

General Manager

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 11 day of MARCH, 1999, on behalf of:

EASTERN UTILITIES

By: [signature]

Of: EASTERN UTILITIES

Its Duly Authorized: DIRECTOR TRANSMISSION SERVICES

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 4th day of March 1999, on behalf of:

Sithe New England Holdings, LLC

By: David L. Schwartz

Of: Latham & Watkins

Its Duly Authorized: Counsel

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999
JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL
AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 5th day of March, 1999, on behalf of:

Com/Electric

By: [signature]

Of: Cameron McKenna LLP

Its Duly Authorized: Attorney

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999 JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 4th day of March, 1999, on behalf of:

Unitil Power Corp.

By: David K. Foote

Of: Unitil Power Corp.

Its Duly Authorized: Senior Vice President

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999
JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL
AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this 4th day of March, 1999, on behalf of:

Fitchbrug Gas and Electric Light Company

By: David K. Foote

Of: Fitchburg Gas and Electric Light Company

Its Duly Authorized: Senior Vice President

JOINDER OF ADDITIONAL PARTY TO FEBRUARY 12, 1999
JOINT STIPULATION BETWEEN NEW ENGLAND POWER POOL
AND COMMISSION TRIAL STAFF

The undersigned, an intervenor in Federal Energy Regulatory Commission Dockets OA97-237-000, et al., hereby joins the February 12, 1999 Joint Stipulation Between New England Power Pool and Commission Trial Staff Regarding Certain Issues Set for Hearing, supports that Stipulation and agrees to be bound by its terms. In accordance with the terms of the Stipulation, the undersigned agrees that the terms of Attachment F to the NEPOOL Tariff, as set forth in Attachment 1 to the Stipulation, the terms of Schedule 1 to the NEPOOL Tariff, as set forth in Attachment 2 to the Stipulation, and the terms of Ancillary Service Schedules 1, 2, 3, 5, 6 and 7 of the NEPOOL Tariff, are just and reasonable, and otherwise in accordance with the requirements of the Federal Power Act and applicable Commission Orders, including, but not limited to, the Commission's April 20, 1998 Order in these dockets.

To implement the terms of the Stipulation, to further support the Stipulation and in consideration of the benefits offered to the undersigned by the Stipulation, the undersigned agrees that it will not offer into the record (or will withdraw such materials if already offered into the record) any pre-filed testimony and exhibits submitted in connection with the hearings currently scheduled to commence on March 2, 1999, which take or support positions that are inconsistent with the terms set forth in the Stipulation.

Respectfully submitted on this ______ day of ________, 1999, on behalf of:

____

By: ______________________________

Of: ______________________________

Its Duly Authorized: ________________

ATTACHMENT F

Annual Transmission Revenue Requirements

The Transmission Revenue Requirements for each Participant will reflect the Participants' costs for Pool Transmission Facilities (PTF). The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of Transmission Providers which are subject to the Commission's jurisdiction, in the Participants' FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula:

I. The Transmission Revenue Requirement shall equal the sum of the Transmission Provider's (A) Return and Associated Income Taxes, (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 Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term Transmission Service under the NEPOOL Tariff and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the applicable rule set forth in the Settlement Agreement entered into in FERC Dockets OA97-237-000, et al. Any changes to that rule must be approved by the Regional Transmission Operations Committee. The rule and any changes thereto shall be filed with the Commission and considered a supplement to this Tariff.

NEPOOL TARIFF, ATTACHMENT F

IMPLEMENTATION RULE FOR CALCULATING ANNUAL TRANSMISSION REVENUE REQUIREMENTS

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each Participant. Such Transmission Revenue Requirements shall reflect the Participant's costs for Pool Transmission Facilities ("PTF"). The Transmission Revenue Requirements will be an annual formula rate calculation, effective June 1, based on the previous calendar year's data, as shown below, and in the case of each Transmission Provider which is subject to the Commission's jurisdiction, in the Participant's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1, using end-of-year balances for each rate base item, as set forth below.

NEPOOL shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year. Further, the informational filing with respect to the determination of the Pool PTF rate would include a breakdown by Participant the amount of the change in PTF investment during the prior year and the PTF retirements or additions causing such change to beginning and end-of-year PTF balances (although beginning-of-year PTF balances are not used in the formula itself), and any additions to PTF, retirements of PTF, and reclassifications of PTF during the year for each Transmission Provider. If there are any corrections made to the information reflected in the informational filing after it has been submitted, NEPOOL would file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, NEPOOL shall make available to Participants and any other interested parties a draft of the proposed filing for review and comment prior to the filing. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The System Operator shall independently audit the charges in effect for the period June 1997 through May 2000 for charges under this Attachment, or direct that an audit[s] be conducted under its supervision by an independent third party, and shall have the discretion to conduct such audits of charges in effect beyond May 2000.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 1 of the NEPOOL Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

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

2. PTF Transmission Plant Allocation Factor shall equal the ratio of PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Hydro-Quebec DC Facilities (HQ Leases).

3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding HQ leases, and Transmission Related General Plant to Total Plant in service excluding HQ Leases.

B. TERMS

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

Amortization of Loss on Reacquired Debt shall equal the Transmission Provider's expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the Transmission Provider's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the Transmission Provider's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the Transmission Provider's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation Expense shall equal the Transmission Provider's general expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal the Transmission Provider's general reserve balance as recorded in FERC Account No. 108.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the Transmission Provider's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

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

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

Payroll Taxes shall equal those payroll expenses as recorded in the Transmission Provider's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the Transmission Provider's balance in FERC Account No.105.

Prepayments shall equal the Transmission Provider's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the Transmission Provider's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant Investment - shall equal the Transmission Provider's transmission plant as defined in the Section 15.1 of the Restated NEPOOL Agreement and determined in accordance with Attachment 1.5 of this rule, which is entitled "Rules for Determining Investment To be Included in PTF."

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the Transmission Provider's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the Transmission Provider's municipal tax expenses as recorded in FERC Account Nos. 408.1, 409.1.

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

Total Transmission Depreciation Reserve shall equal the Transmission Provider's transmission reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal the Transmission Provider's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573, and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the Transmission Provider's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the Transmission Provider's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the Transmission Provider's (A) Return and Associated Income Taxes, (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) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term Transmission Service under the NEPOOL Tariff and (O) Transmission Rents Received from Electric Property.

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

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

(a) PTF Transmission Plant will equal the balance of the Transmission Provider's PTF Investment in Transmission Plant excluding (i) the Transmission Provider's capital leases in the Hydro-Quebec DC Facilities (HQ Leases), (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the Tariff, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II HVDC facilities.

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

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

(d) Transmission Related Depreciation Reserve shall equal the 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 General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF Transmission Plant Allocation Factor.

(e) Transmission Related Accumulated Deferred Taxes shall equal the Transmission Provider's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF Transmission Plant Allocation Factor.

(f) Transmission Related Loss on Reacquired Debt shall equal the Transmission Provider's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF Transmission Plant Allocation Factor.

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

(h) Transmission Prepayments shall equal the Transmission Provider's electric balance of prepayments multiplied by the Transmission Wages and Salaries allocator and further multiplied by the PTF Transmission Plant Allocation Factor.

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

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.

2. Cost of Capital Rate

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

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

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

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

(iii) the return on equity component, which shall be determined as follows:

(a) For each year during the period March 1, 1997 through May 31, 2000, the return on equity component for each of the Transmission Providers identified below shall be the product of the Transmission Provider's Return on Equity ("ROE") as set forth below and the ratio that common equity is to the Transmission Provider's total capital:

Bangor Hydro-Electric Company	11.50%
Boston Edison Company	10.65%
Central Maine Power Company	11.00%
Commonwealth Electric Company	10.75%
Eastern Utilities Associates	11.22% (through May 31, 1999) 10.65% (beginning June 1, 1999)
New England Electric System	10.65%
The United Illuminating Company	11.5% (through May 31, 1999) 10.75% (beginning June 1, 1999)
Vermont Electric Company	11.50%
Northeast Utilities	11.75%

(b) For each year during the period commencing June 1, 2000, the return on equity component shall be determined in the same manner, and the allowed ROE for each Transmission Provider identified above shall remain in effect for purposes of such determination for the Provider until an amendment to its cost of service under the Local Network Service Tariff for the Provider filed after December 31, 1999 results in a different allowed ROE for that Provider, in which case that Provider's ROE shall be set for purposes of such determination at the ROE ultimately determined to be just and reasonable in the proceeding involving the applicable Local Network Service Tariff amendment.

(b) Federal Income Tax shall equal

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

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

(c) State Income Tax shall equal

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

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

B. Transmission Depreciation Expense shall equal the PTF Transmission Plant Allocation Factor, multiplied by the sum of Depreciation Expense for

Transmission Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.

C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the Transmission Provider's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF Transmission Plant Allocation Factor.

D. Transmission Related Amortization of Investment Tax Credits shall equal the Transmission Provider's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF Transmission Plant Allocation Factor.

E. Transmission Related Municipal Tax Expense shall equal the Transmission Provider's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF Transmission Plant Allocation Factor.

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

G. Transmission Operation and Maintenance Expense shall equal Transmission Operation and Maintenance Expenses multiplied by the PTF Transmission Plant Allocation Factor.

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

I. Transmission Related Integrated Facilities Charges shall equal the Transmission Provider's transmission payments to affiliates for use of the PTF integrated transmission facilities of those affiliates.

J. Transmission Support Revenues shall equal the Transmission Provider's revenue received for PTF transmission support but excluding the support payments to Transmission Providers or their designee pursuant to Schedule 11 of the Tariff.

K. Transmission Support Expense shall equal the expense paid by Transmission Providers or Transmission Customers for PTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular Participants or other entities in accordance with the NEPOOL Tariff. Transmission Support Expenses by any entity other than an LNS Transmission Provider, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its Point to Point Service for each individual Point to Point transaction from the resource with which the support payment is associated. For the purpose of establishing this cap, for the first five years of the Transition Period the annual payment for RNS and Internal Point-to-Point shall be recalculated at the Pool PTF rate.

L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the Management Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by NEPOOL with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the NEPOOL Tariff.

M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.

N. Revenues for Short-term Transmission Service under the NEPOOL Tariff shall be revenues distributed to each Participant, from NEPOOL, for short term service provided under the NEPOOL Tariff, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.

O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.

Attachment 5

Rules for Determining Investment To be Included in PTF

Section A - Transmission Lines

Section B - Terminal Facilities

Section C - Right of Way

Section A

Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF), under the New England Power Pool Agreement, are the transmission facilities owned by Participants rated 69 KV or above required to allow energy from significant power sources to move freely on the New England Transmission network, and include:

1. All transmission lines rated 69 KV and above, except:

   a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

   b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

   c. lines that are normally operated open.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a Participant with significant generation in its system (initially 25 MW) is connected to the New England network and none of the transmission facilities owned by the Participant qualify to be included in PTF as defined in "1" and "2" above, then such Participant's connection to PTF will constitute PTF if both of the following requirements are met:

   a. The connection is rated 69 KV or above.

   b. The connection is the principal transmission link between the Participant and the remainder of the New England PTF network.

   The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the Participant's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to a load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of an EHV-PTF or LV-PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of EHV-PTF, LV-PTF, or non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

Pool Transmission Facilities will be divided into two categories; EHV-PTF (230 KV and above) and LV-PTF (below 230 KV). The Management Committee will review, at least annually, the status of facilities classified as EHV-PTF to determine whether any such facilities should be terminated or others added because of change in use.

All new facilities being installed should be properly classified at the time the facilities are approved under Section 10.4. Except as noted in paragraph 9d of Section B, autotransformers from EHV-PTF to LV-PTF and their associated high voltage switching equipment will not be classified as part of the EHV-PTF system but will be classified as LV-PTF if they meet the requirements for PTF.

Section B

Rules for Determining Terminal Investment To be Included in PTF

1. The total investment in terminal facilities shall be included where these facilities are identifiable and serve solely and directly for terminating and/or switching PTF lines. Excluded are all facilities which exist solely to supply load or connect generation to the system where the switching or terminations would not otherwise exist except for the load and/or generation.

2. In cases where a line terminal is used in conjunction with both PTF and non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal would be required in the absence of the non-PTF lines and/or facilities. For example, if a PTF line and a non-PTF transformer share a common switching position on a bus, the full cost of the switch position will be PTF investment unless excluded by item 1 or modified as in item 5.

3. Where line terminals are installed solely for non-PTF lines and/or facilities, such terminal cost shall not be included in PTF.

4. A transformer which connects PTF facilities of different voltage along with any switchgear which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. When an autotransformer is used to connect PTF facilities of different voltage, and its tertiary winding serves local load or non-PTF facilities, the investment in such transformer and associated facilities (such as structures, disconnect switches, circuit breakers, etc.) shall be allocated between non-PTF and PTF on the basis of the ratio of one half the capacity of the tertiary winding to the sum of one half the capacity of the tertiary winding and the full secondary winding capacity. The use of one half the capacity of the tertiary is arbitrary, but is based on the minor loads which would generally be supplied from the tertiary winding.

6. When a transformer supplies only non-PTF transmission or distribution, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures, shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities - The investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a non-PTF function shall be excluded. The investment in land, structures, ground matts, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities - In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities.

9. The allocation of investment between EHV-PTF and LV-PTF shall follow the same principals as given for the allocation of investment between PTF and non-PTF as outlined in paragraphs 1 to 8. For example:

   a. When a transformer is used to interconnect EHV-PTF and LV-PTF, the investment in the high side disconnect switch (and circuit breakers if applicable) and the transformer will be included in the LV-PTF. IF the transformer shares a switching position with an EHV-PTF line, any high side circuit breakers associated with the position shall be considered as EHV-PTF as long as the breakers are required for EHV-PTF line switching and not solely to permit the installation of the transformer.

   b. The investment in the portion of multi-use terminal facilities other than transformers, which are identifiable as serving an EHV-PTF function shall be included in the EHV-PTF, while the investment in such facilities which are identifiable as serving a LV-PTF function shall be included in LV-PTF. The investment in land, structures, ground matts, fences, ducts, lighting, etc., can generally be identified and thus allocated.

The investment in other facilities, excluding transformers, which are not identifiable as serving either EHV-PTF or LV-PTF function and general overheads shall be allocated to EHV-PTF on the basis of the ratio of the investment in the facilities identified as EHV-PTF to the sum of the investments in the facilities which are identified as serving EHV-PTF and LV-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment.

c. EHV switching facilities shall be considered as LV-PTF if the EHV switching was required solely to permit the installation of autotransformers to feed the LV-PTF.

d. When an autotransformer is used to connect EHV-PTF to LV-PTF and its tertiary winding serves to connect reactors (used to control voltage on the EHV-PTF) to the system, the investment in such transformer and associated facilities (such as structures, disconnect switches, circuit breakers, etc.) shall be allocated between the EHV-PTF and the LV-PTF on the basis of the ratio of the rating of the reactor to the sum of such rating and the rating of the low voltage winding of the autotransformer.

10. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

11. Generator unit transformers and generator circuit breakers shall be excluded from PTF.

12. When making the above cost allocations for transformers, the highest nameplate ratings should be utilized.

13. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by these facilities.

Section C

Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If a R/W has only PTF lines but includes additional unused R/W which was purchased for future use by non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

   a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

   b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

   c. Where a R/W is widened, but the new facilities, either PTF or non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W (see examples).

4. In allocating R/W between PTF and non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae:

   a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

   b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. Where a R/W is shared by EHV-PTF and LV-PTF, the allocation between them shall be in the same manner as between PTF and non-PTF.

6. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the NEPOOL Executive Committee unless included under paragraph 1.

7. Examples:

Example 1 - One 345 KV H-frame line and one 115 KV H-frame line share a 200 ft. R/W. An independent 345 KV line would require 170 ft. of R/W and an independent 115 KV line, 85 ft. The portion of the 200 ft. R/W allocated to the 345 KV line would be 170/255 and the portion allocated to 115 KV line would be 85/255.

Example 2 - A 100 ft. 115 KV R/W is widened 100 ft. to accommodate a new 345 KV line. As in Example 1, the 345 KV line would be allocated 66.7% (170 ft./255 ft.) of the 200 ft. R/W. This would be made up of 100 ft. of the new R/W and 33 ft. of the old R/W. The remaining 67 ft. of the old R/W would be allocated to the 115 KV line.

Example 3 - A 100 ft. 115 KV R/W is widened 50 ft. and the old 115 KV line removed to accommodate a new composite steel pole line with a 345 KV circuit on one side and a 115 KV circuit on the other. In this instance, the appropriate structure type for the 345 KV line would be a steel pole structure with conductors in a vertical configuration on one side and requiring a R/W width of 120 ft. The appropriate structure type for the 115 KV line would be a steel pole structure with conductors in a vertical configuration on one side and requiring a R/W width of 60 ft. The 345 KV line would be allocated 66.7% (120 ft./180 ft.) of the 150 ft. R/W which equals 100 ft. The R/W allocated to the 345 KV line would include 50 ft. of new R/W and 50 ft. of old R/W. The remaining 50 ft. of the old R/W would be allocated to the 115 KV line.

Example 4 - A 140 ft. right-of-way presently occupied by two double-circuit 115 KV lattice tower lines is widened 10 ft. to permit replacing one of the double-circuit 115 KV lines with a double-circuit steel pole composite structure similar to that specified for Example 3. As in Example 3, the 345 KV circuit would be allocated a width of 120 ft. and the new 115 KV circuit a width of 60 ft. If all of the 115 KV circuits are of the same classification (such as LV-PTF), the 115 KV width requirements can be combined.

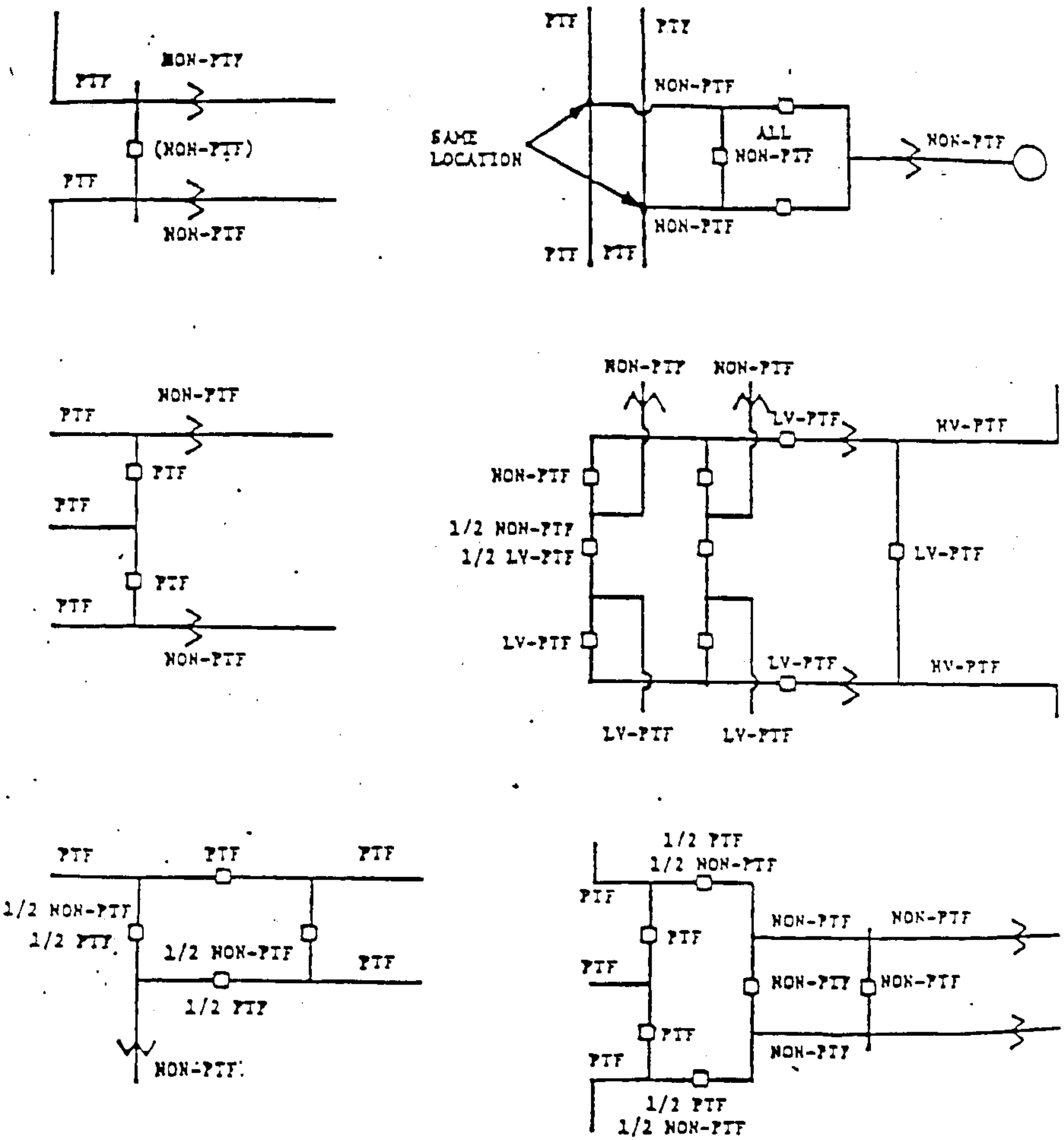
Thus, the 115 KV allocation could be 115 ft. (60 ft. plus 55 ft.). The 55 ft. of right-of-way assigned to the remaining lattice tower structure is based on a 25 ft. phase spacing across the tower and 30 ft. of side clearance to the edge of the right-of-way. The 345 KV right-of-way allocation would be 51.2% (120 ft. 235 ft.) of the 150 ft. R/W. This equals 77 ft., 10 ft. of which would be new R/W and 67 ft. of which would be old R/W. The remaining 73 ft. of old R/W would be allocated to all of the 115 KV circuits.

In making these allocations, each company should utilize R/W widths which are appropriate for their territory and type of structure designs.

AT5NAB12:DMS:vmm
NABS3 03/22/90

Attachment 5

EXAMPLES OF THE METHODS FOR DISTINGUISHING PTF FROM NON-PTF FACILITIES IN A NUMBER OF TYPICAL SUBSTATION CONFIGURATIONS

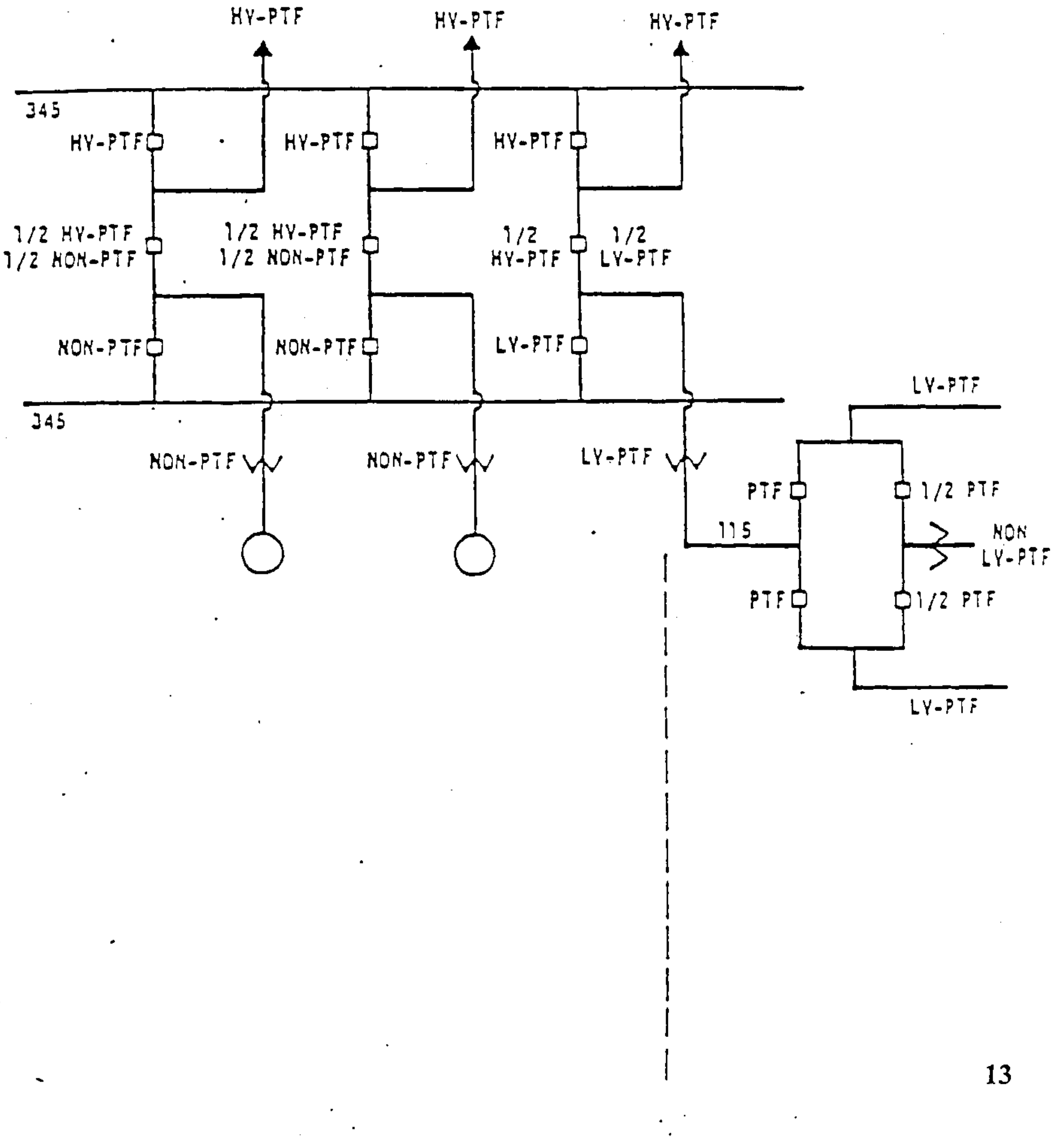


Attachment 5

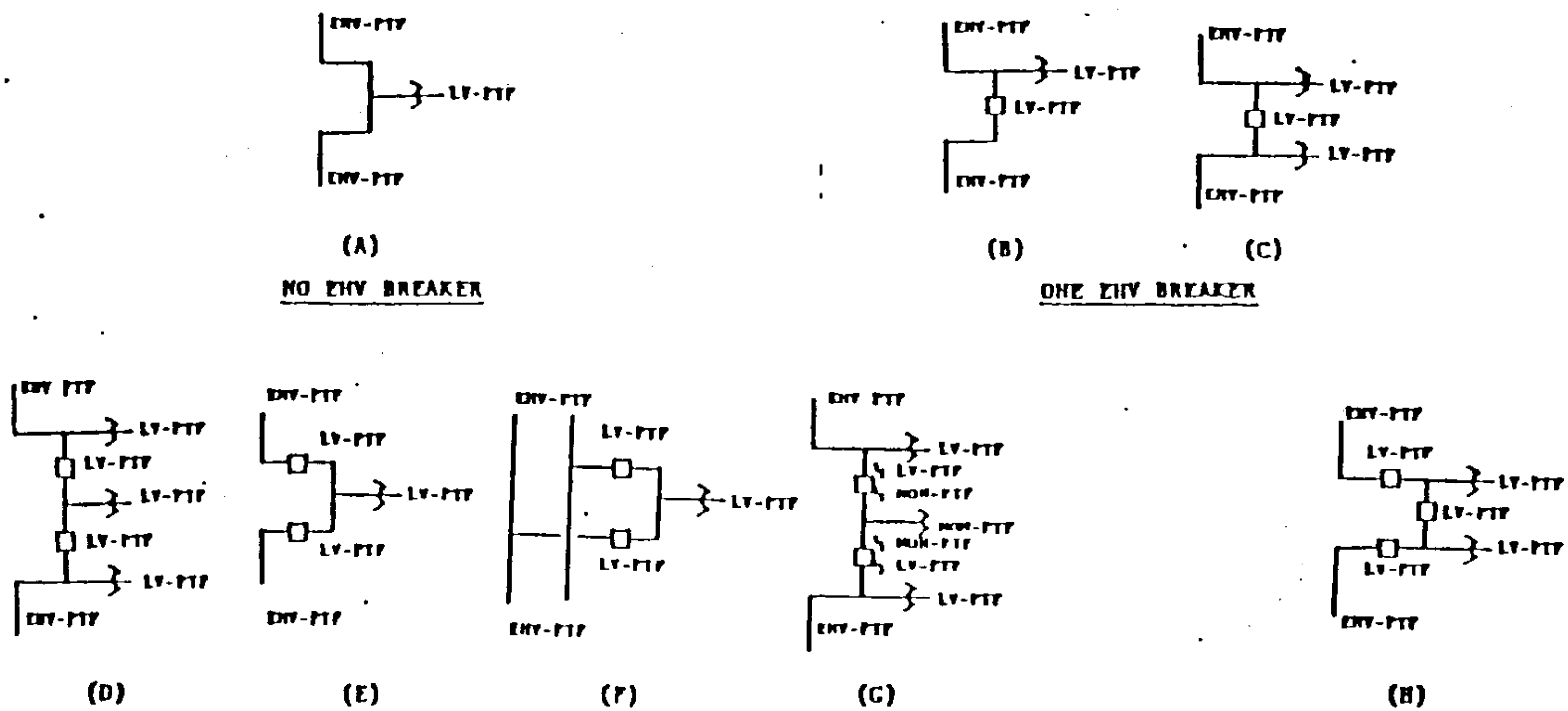
EXAMPLES OF THE METHODS FOR DISTINGUISHING

PTF FROM NON-PTF FACILITIES IN A NUMBER OF

TYPICAL SUBSTATION CONFIGURATIONS



EHV-PTF ALLOCATION
WITHOUT EHV BREAKER ALLOCATION



NO EHV BREAKER

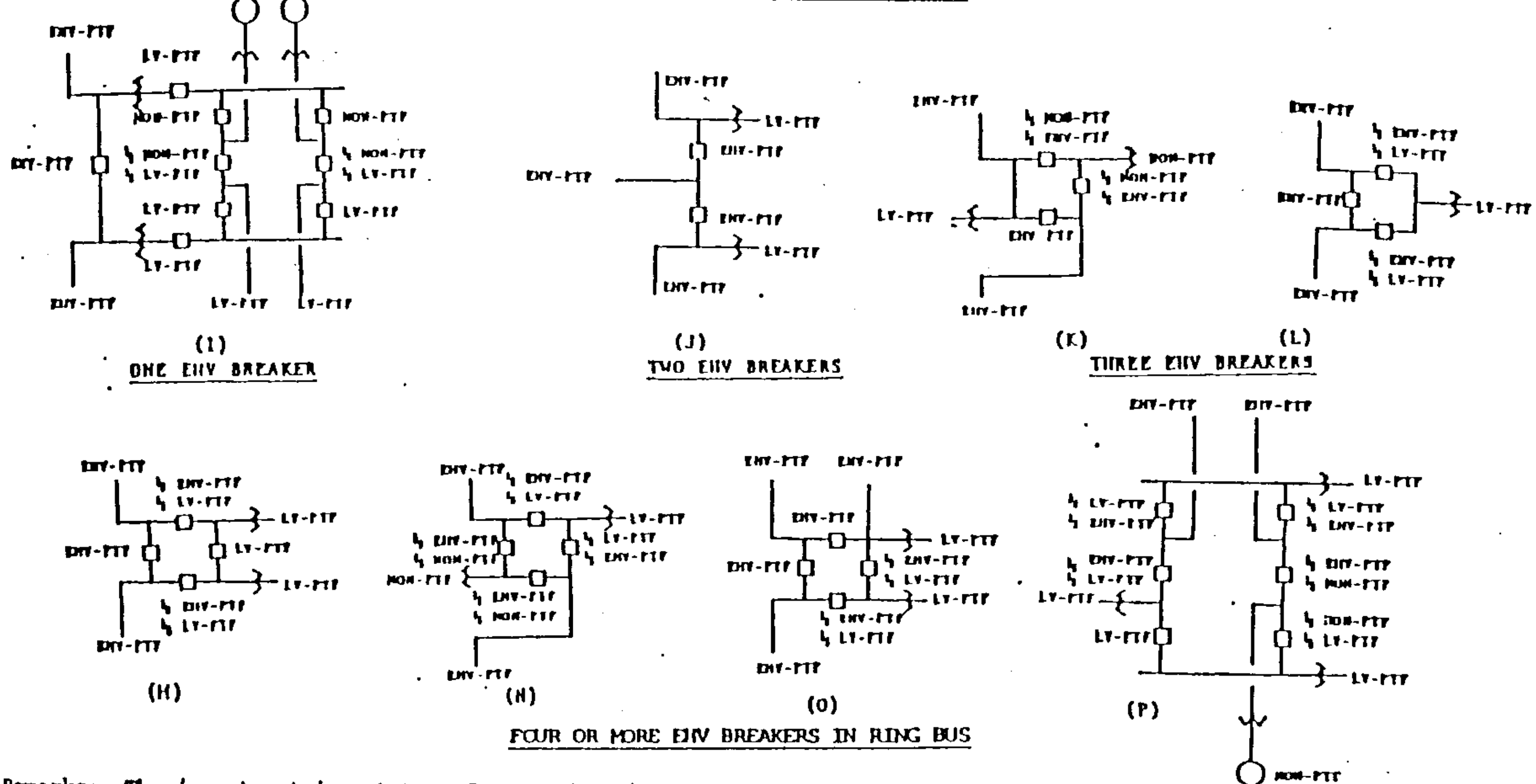
ONE EHV BREAKER

TWO EHV BREAKERS

THREE EHV BREAKERS

urkat When an EHV-PTF transmission line is tapped or looped to supply one or more autotransformers (or tie transformers) to feed LV-PTF facilities, the EHV switching facilities shall be considered as LV-PTF if the EHV switching was required solely to permit the installation of the autotransformer(s) (Section B.9.c). The investment in autotransformers (or tie transformers) which feed LV-PTF facilities, including the high side disconnect switches (and circuit breakers if applicable), will be included in LV-PTF (Section B.9.a.).

EHV-PTF ALLOCATION WITH EHV BREAKER ALLOCATION



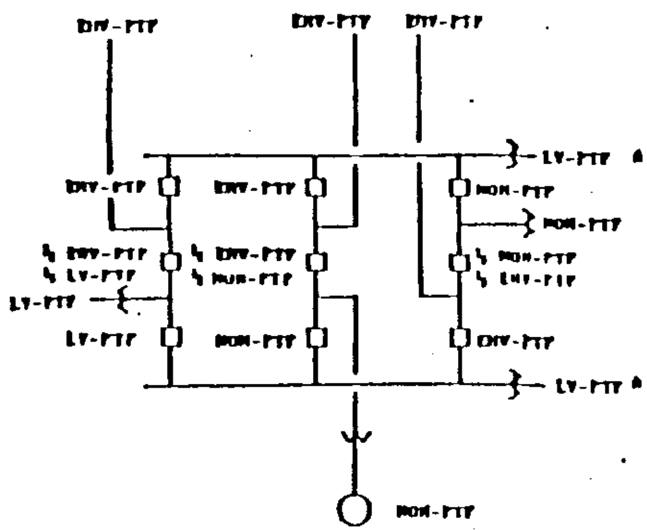
Remarks: The investment in autotransformers (or tie transformers) which feed LV-PTF facilities, including the high side disconnect switches (and circuit breakers if applicable), will be included in LV-PTF (Section B.9.a.).

If the transformer shares a switching position with an EHV-PTF line, any high side circuit breakers associated with the position shall be considered as EHV-PTF as long as the breakers are required for EHV-PTF line switching and not solely to permit the installation of the transformer (Section B.9.a.).

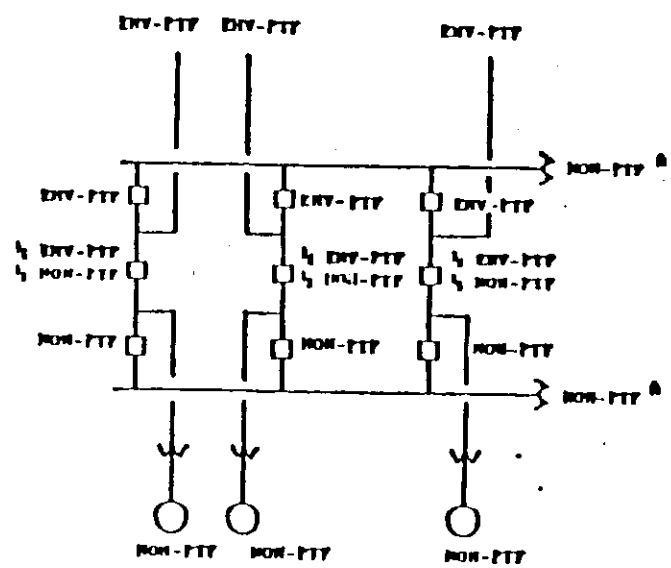
The EHV switching is considered as EHV-PTF for any switching station with three or more EHV-PTF transmission lines or any switching station with two lines and an EHV ring bus; however, not all of the EHV breakers must be so classified.

The EHV switching in a generating station with only two EHV-PTF transmission lines (such as Figure I) shall be classified as EHV-PTF where 100 MW's or more of generation is connected directly to the transmission network at that station (at either EHV or LV).

EHV-PTF ALLOCATION STATION
WITH EHV BREAKER AND A HALF CONFIGURATION



(Q)



(R)

BREAKER AND ONE HALF ARRANGEMENT

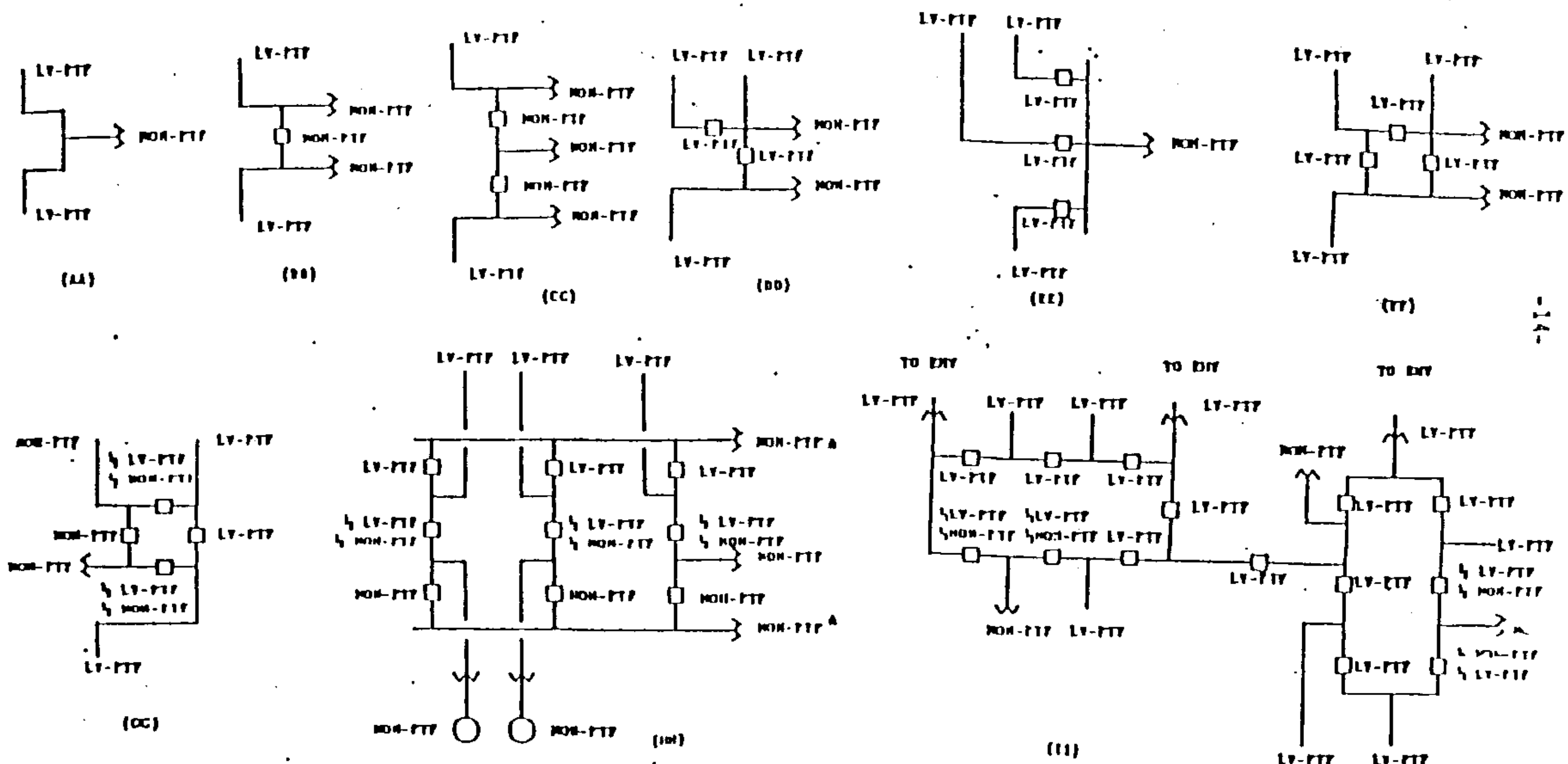
Remarks: For the breaker and a half configuration, the costs associated with the center breakers shall be allocated one half to each of the functions of the facilities connected each side of the breaker. The costs associated with the outside breakers shall be allocated to the function of the facility in that position.

The costs associated with the end busses shall be allocated in accordance with the number of EHV breakers assigned to each function (Section B.9.).

* When an end bus is used to supply a LV-PTF or Non-PTF transformer without a series breaker, the equivalent of one circuit breaker cost shall be allocated to the LV-PTF or Non-PTF function and the allocated costs of the multiple breakers connected to that end bus proportionally reduced.

Attachment 5

LV-PTF ALLOCATION



Remarks: All facilities which exist solely to supply load or to connect generation to the system, where the switching or terminations would not otherwise exist, shall be excluded from the LV-PTF allocation (Section B.1). Where line terminals are installed solely for Non-PTF lines and/or facilities, such terminal costs shall not be included in PTF (Section B.3.). If a LV-PTF line and a Non-PTF transformer share a common switching position, the full cost of the switch position shall be a LV-PTF investment (Section B.2.).

The LV switching is considered as LV-PTF for any switching station with three or more LV-PTF transmission lines or any switching station with two lines and a LV ring bus; however, not all of the LV breakers must be so classified.

The LV switching in a generating station with only two LV-PTF transmission lines shall be classified as LV-PTF where 100 MW's or more of generation is connected directly to the transmission network at that station (at either LV or distribution voltage).

- For the breaker and a half configuration (Figure HH), where an end bus is used to supply a Non-PTF transformer without a series breaker, the equivalent of one circuit breaker cost shall be allocated to the Non-PTF function.

Attachment 6

Pool Planned Units and EHV Originating Systems

	Unit Name	Originating System For EHV
	Canal 2	*CES/EUA
	New Haven Harbor	UI
	Potter 2	BE
	Stony Brook 2A	NU
	Stony Brook 2B	NU
	Stony Brook Composite	NU
	Yarmouth 4	CMP
	Mystic 7	BE
	Millstone 3	NU
	Seabrook 1	PSNH
**	HQ Interconnection	NEES
***	Waters River #2	NEES

* Commonwealth Electric is the originating system for its ownership share of Canal 2. EUA is the originating system for its ownership share of Canal 2.

** Entitlement Transfers per NEPOOL Agreement Sections 13.2(c) and 13.4(b) and HQ Phase II Net Transfer Responsibility per NEPOOL Agreement Section 13.4(b).

*** 7 Mw summer(June-Sept.) and 12 Mw winter(Oct.-May).

DES/ees:AT6NAB12.NABS3
5-28-91

Attachment 1.5

Rules for Determining Investment

To be Included in PTF

Section A - Transmission Lines

Section B - Terminal Facilities

Section C - Right of Way

Section A
Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF), under the New England Power Pool Agreement, are the transmission facilities owned by Participants rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission network, and include:

1. All Transmission lines rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

    c. lines that are normally operated open.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a Participant with significant generation in its system (initially 25 MW) is connected to the New England network and none of the transmission facilities owned by the Participant qualify to be included in PTF as defined in "1" and "2" above, then such Participant's connection to PTF will constitute PTF if both of the following requirements are met:

    a. The connection is rated 69 kV or above.

    b. The connection is the principal transmission link between the Participant and the remainder of the New England PTF network.

    The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the Participant's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The Regional Transmission Planning Committee will review, at least annually, the status of facilities PTF to determine whether any such facilities should be terminated or others added because of change in use.

All new facilities being installed should be properly classified at the time the facilities are approved under Section 18.4.

Section B
Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is non-PTF.

3. Where line terminals are installed solely for non-PTF lines and/or facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switchgear which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities - the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and non-PTF

functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities - In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England Utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by these facilities.

12. The Management Committee may designate appropriate facilities as PTF.

Section C
Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by non-PTF lines, the cost of the additional R/W is not to be included as PTF.

3. If the R/W contains both PTF and non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

    a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

    b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

    c. Where a R/W is widened, but the new facilities, either PTF or non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae:

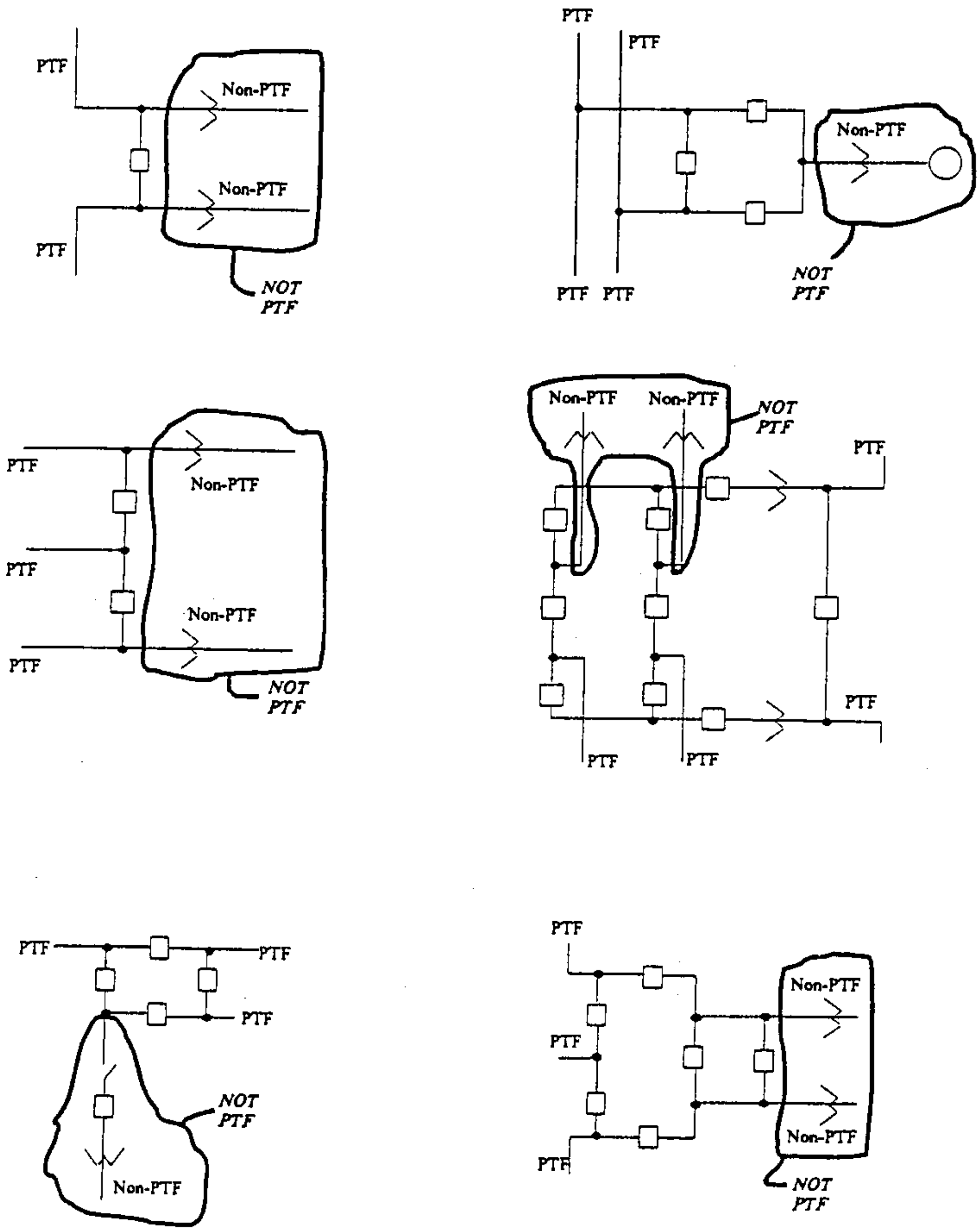
    a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

    b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

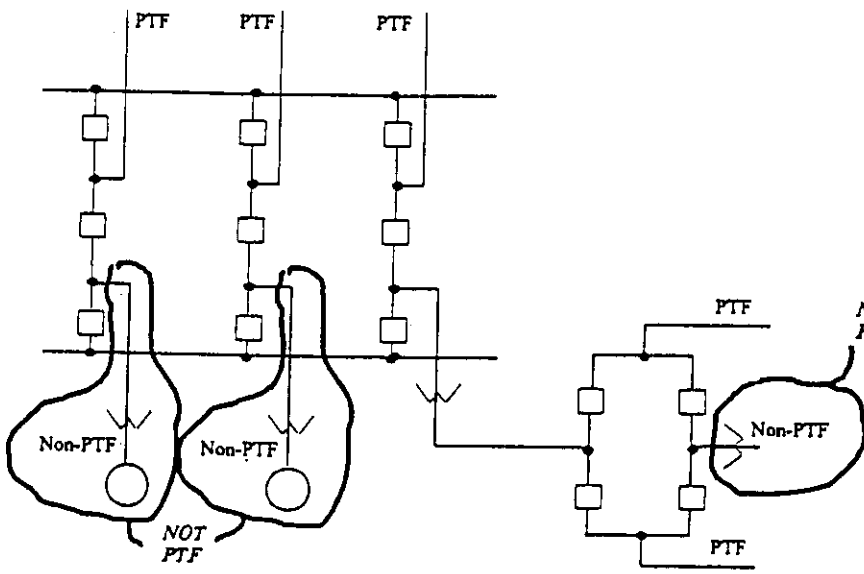
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the NEPOOL Executive Committee included under paragraph 1.

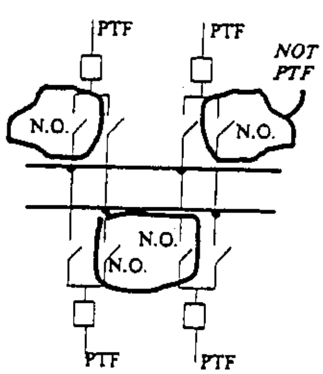
REMINDER: ADDITIONAL PAGES ARE DIAGRAMS THAT SHOULD BE INCLUDED W/ THIS DOCUMENT; DOCUMENT IS NOT COMPLETE WITHOUT ADDITIONAL PAGES.

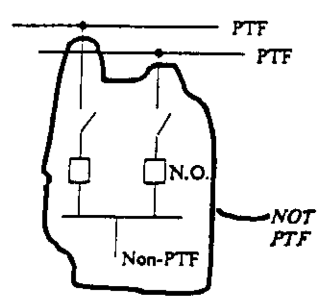
Attachment 2.1
Examples of the Methods for Distinguishing PTF from Non-PTF Terminal Facilities in a Number of Typical Substation Configurations



Attachment 2.1
Examples of the Methods for Distinguishing PTF from Non-PTF Terminal Facilities in a Number of Typical Substation Configurations







INTERPRETIVE GUIDANCE AS TO CERTAIN QUESTIONS ARISING IN THE CONTEXT OF THE RNS AUDIT MANDATED BY THE SETTLEMENT AGREEMENT REACHED IN THE TARIFF DOCKET

BACKGROUND

On December 31, 1996, the NEPOOL Executive Committee filed a comprehensive restructuring proposal which included the Restated NEPOOL Agreement and the NEPOOL Tariff. By order dated April 20, 1998, New England Power Pool, 83 FERC ¶61,045 (the "April 20 Order"), the Commission conditionally accepted the NEPOOL Tariff, but directed that a public hearing be held with respect to, among other things, the justness and reasonableness of the formulas in Attachment F and of Ancillary Service Schedule 1 to the NEPOOL Tariff. That hearing was conducted before Presiding Administrative Law Judge Lawrence Brenner in March, 1999 (the "Tariff Docket"). On April 7, 1999, the parties to the Tariff Docket filed with the Commission a "Comprehensive Agreement Resolving All Issues Raised in this Proceeding Except for One Issue Raised by Great Bay Power Company" (the "Settlement Agreement"). The Settlement Agreement resolved issues regarding the justness and reasonableness of Attachment F and the Ancillary Service Schedules to the NEPOOL Tariff set for hearing in the Tariff Docket pursuant to the Commission's April 20 Order. Incorporated into and made a part of the Settlement Agreement was the February 12, 1999 stipulation entered into between NEPOOL and Commission Trial Staff (the "NEPOOL-Staff Stipulation" or "Stipulation"), which resolved various issues raised by Staff in the underlying proceeding. By order dated July 30, 1999, New England Power Pool, 88 FERC ¶61,140 (the "July 30 Order"), the Commission approved the Settlement Agreement.

Section 6 of the Stipulation provides, in pertinent part, as follows:

> [ISO New England, Inc.] shall independently audit the charges in effect for the period June 1997 through May 2000, or direct that an audit[s] be conducted under its supervision by an independent third party. Such audit[s] shall verify, through such sampling as appropriate, that Transmission Providers are correctly accounting for PTF investment in accordance with the applicable NEPOOL rules for determining PTF investment. The results of any such audit[s] shall be filed with the Commission as an informational filing, and the charges recalculated to correct any errors identified in such audit, with refunds and surcharges, as appropriate, for any amounts previously over- or under-charged due to such errors.

To complete the audit required by Section 6 of the Stipulation (the "RNS Audit"), ISO-NE engaged Rhema Services, Incorporated ("RSI"). RSI has been tasked to perform the RNS Audit pursuant to an audit scope document jointly approved by ISO-NE and NEPOOL (the "RNS RFP") and an agreement between ISO-NE and RSI. The RNS RFP provides, among other things, that the RNS Audit is to be "managed by ISO-NE, and both ISO-NE and [NEPOOL Transmission Settlement Subcommittee] members will assist the auditor as necessary."

With respect to the RNS revenue requirement, Section 4.1(a) of the RNS RFP provides that the objective of the audit was to:

> Verify that each Participant[']s costs for PTF agree with their FERC Form 1, and other supporting documentation, and meet the requirements of NEPOOL OATT-Attachment F and the Implementation Rule. For all owners and non-owners of PTF, the data submitted should conform with the intent and principles of the NEPOOL OATT-Attachment F and FERC Form 1.

With respect to the NEPOOL RNS Model, Section 4.1(b) of the RNS RFP provides that the objective of the audit was to:

> For each Participant, verify the clerical accuracy and that the data submitted to ISO-NE on the input document agrees with appropriate supporting documentation.

With respect to PTF cost accounting, Section 4.1(c) of the RNS RFP provides that for each Participant the objective of the audit was to:

> Verify, through such sampling as appropriate, that each Participant's PTF/non-PTF allocation of transmission plant or substation (as listed in the NEPOOL PTF Catalog), used to develop each Company's PTF allocation factor, conforms to the accounting methods described in the Implementation Rule.

In accordance with AICPA Consulting Standards, the auditors are to determine whether each Transmission Owner is "In Compliance," in "Partial Compliance," or "Out of Compliance" with the requirements of the Restated NEPOOL Agreement ("RNA"), the NEPOOL OATT-Attachment F and the Implementation Rule. Those terms are defined in the RNS RFP as follows:

> "In Compliance" means the reported data and the RNS rate calculation have substantially met all of the requirements of the RNS, NEPOOL OATT-Attachment F and the Implementation Rule.
>
> "Partial Compliance" means that some inconsistencies were noted between the reported data and/or the RNS rate calculation relative to the requirements of the RNS, NEPOOL OATT-Attachment F and the Implementation Rule.
>
> "Out of Compliance" means that significant inconsistencies were noted between the reported data and/or the RNS rate calculation relative to the requirements of the RNS, NEPOOL OATT-Attachment F and the Implementation Rule.

As the RNS Audit has progressed, a number of questions have been raised by RSI, ISO-NE, the NEPOOL Transmission Settlement Subcommittee ("TSS"), individual investor-owned Transmission Owners (IOTOs") and individual Municipal Transmission Owners ("MTOs") regarding the interpretation and application of various aspects of the Implementation Rule. ISO-NE and NEPOOL agree that clarification or guidance from NEPOOL as to these issues is desirable to assure that the ultimate product from RSI satisfies the intent and purpose of Section 6 of the Stipulation.

The TSS is a subcommittee of the NEPOOL Tariff Committee ("TC") charged specifically with the responsibility for assuring that the requirements of the Implementation Rule are satisfied, and more generally with developing the annual revenue requirement for PTF pursuant to the Implementation Rule. The TSS, on behalf of NEPOOL, submits this document to provide further guidance and clarification to RSI with respect to the interpretation and application of certain aspects of the Implementation Rule.

The TSS notes, as a preliminary matter, that the Implementation Rule and the requirements of Section 6 of the Stipulation must be considered in the overall context of the claims made and disputes raised in the Tariff Docket and the compromises reached to resolve those claims and disputes reflected in the Implementation Rule and Section 6 of the Stipulation. The primary purpose of the Implementation Rule is to assure that Attachment F fairly captures each Participant's actual PTF-related costs and excludes non-PTF costs, and that the PTF costs are determined from adequate, verifiable and documented information. The primary purpose of Section 6 is to assure that the Implementation Rule has been properly and consistently applied to accomplish that end.

In developing this guidance paper, the TSS responds to certain general issues raised in connection with RSI's activities to date. The TSS believes that the interpretational guidance provided now should eliminate potential inconsistencies in RSI's exceptions and otherwise address the concerns raised to date with draft audit report(s) produced to date.

The TSS appreciates the submission by RSI of a number of recommendations for clarifying and improving certain aspects of the Implementation Rule. The TSS will consider those recommendations with a view toward determining the appropriate improvements to the Implementation Rule to be applied prospectively.

IMPLEMENTATION RULE: Section II.A.2(a)(i)

RSI has requested guidance as to the determination of the "embedded cost to maturity" factor of the long-term debt component of the weighted cost of capital calculation of the Cost of Capital component of the Attachment F formula. RSI has noted that the Transmission Owners appear to be utilizing different methods of determining this factor. The Implementation Rule does not specify a particular methodology that must be used to determine the "embedded cost to maturity" factor. Accordingly, provided that the Transmission Owner utilizes a traditionally accepted and recognized accounting methodology to determine its actual embedded cost to maturity and RSI is satisfied that the documentation offered by that Transmission Owner is sufficient to support the determination made by the Transmission Owner under the applicable methodology, the Transmission Owner should be considered to be in compliance with the requirements of this aspect of the Implementation Rule.

USE OF COSTS ASSIGNED TO THE TRANSMISSION FUNCTION RATHER THAN ALLOCATED COSTS

A number of the components of the Attachment F formula, as defined in the Implementation Rule, indicate that allocation factors are to be applied to amounts recorded in specific FERC accounts in order to determine the portion of such amounts to be applied to PTF.

In its draft audit reports, RSI has identified as exceptions instances in which Transmission Owners have separately functionalized amounts in such accounts that reflected PTF, rather than relying on allocation factors to determine various components of the Attachment F formula, as defined in the Implementation Rule. The issue has been specifically identified by RSI and/or the Transmission Owners with respect to the following Sections of the Implementation Rule but is not necessarily limited to those Sections: Sections II.M (Transmission Related Taxes and Fees Charge), II.A.1(c) (Transmission Plant Held for Future Use), II.A.1(e) (Transmission Related Accumulated Deferred Income Taxes), II.A.1(g) (Other Regulatory Assets/Liabilities), II.F (Transmission related Payroll Taxes) and II.A.E (Transmission Related Municipal Tax Expense).

The issue raised by these facts is whether the interests of consumers and the intent of the Settlement Agreement and RNS Audit is better served by relying on actual data verified in audit or reverting to allocated data. The intent of the parties executing the Settlement Agreement and the NEPOOL Participants as a whole is to implement Attachment F in a manner that most accurately reflects a Participant's actual PTF-related costs. Although the Implementation Rule refers to the use of allocation factors as a proxy for determining how much within certain accounts should be considered PTF-related, the intent of the Implementation Rule and the interests of customers and the Participants are better served by the use of actual data in lieu of allocated data, provided that the Transmission Owner has adequate and verifiable documentation to support the functionalized data. Accordingly, as a general rule, functionalized data is preferred over allocated data, and the purpose of the audit with respect to the functionalized data should be to determine whether there is adequate documentation to support the functionalization.

RSI in its draft audit reports and discussions with Transmission Owners has identified as exceptions circumstances in which a Transmission Owner used actual, functionalized data rather than allocated data but did not specifically reference in its FERC Form 1 that actual data was being used. The overall intent of this portion of the Implementation Rule was to assure that the data sources used for inputs were readily identifiable and verifiable. Where a Transmission Owner has not used allocated data and

RSI is satisfied that there is adequate supporting documentation available to support the functionalization, the TSS believes that the intent of the Implementation Rule has been satisfied and, further, that the purpose of the RNS Audit contemplated by Section 6 of the Stipulation would not be advanced by identifying the failure of the Transmission Owner to make the appropriate entry in the FERC Form 1 as an exception or lack of compliance resulting in an adjustment for those costs. The TSS notes further that the data relied upon by each Transmission Owner in submitting its Attachment F revenue requirements is verifiable, filed with appropriate regulators and/or subject to independent audits.

The TSS, in the process of developing the RNS revenue requirements going forward, will work to assure that the Transmission Owners specifically identify in their FERC Form 1s instances in which actual data is being used in lieu of allocated data.

IMPLEMENTATION RULE: Section II.A.1(i) (Transmission Materials and Supplies)

Section II.A.1(i) references FERC Account 154 (incorporated by definition in the term "Transmission Plant Materials and Supplies"). Account 154 is reported on page 227 on FERC Form 1 which permits the use of estimating of amounts by function. Accordingly, this aspect of the Implementation Rule should be read to permit the use of allocated or functionalized data. If allocated data is utilized, the Plant Allocation Factor (as defined in Section I.A.3) is a reasonable basis for allocating materials and supplies and may properly be used to make the allocation.

TRANSMISSION SUPPORT REVENUE AND EXPENSES

Section II.A.1.(j) of the Settlement Agreement provides, in pertinent part, that Transmission Related Cash Working Capital properly reflected in the Transmission Investment Base includes 12.5% of the "Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue." RSI has suggested a change to the Implementation Rule to recognize that some Transmission Owners receive Transmission Support Revenues in excess of Transmission Support Expense and that excess should reduce their cash working capital requirements.

The TSS is not aware that RSI has identified any Transmission Owner as Out of Compliance or in Partial Compliance with the Implementation Rule based on RSI's suggested change. However, by way of background, the provisions of the Implementation Rule concerning the treatment of Transmission Support Expense and Transmission Support Revenue were extensively and intensively negotiated to address a number of complex and interrelated concerns regarding the recoverability under the restructured NEPOOL arrangements of payments made under other pre-existing bilateral agreements for the support of certain PTF. The agreement of the settling parties reflected in Section II.A.1.(j) should be implemented as worded to avoid undoing the complex compromise reflected in that provision.

IMPLEMENTATION RULE: Section II.O (Other Transmission Related Revenue)

Section II.O provides that Transmission Rents from Electric Property included in Account 454 associated with PTF Transmission Plant are to be used as a revenue credit. RSI has suggested expanding this definition to include any revenue derived from PTF Transmission Plant (not reflected in Transmission Support Revenues) including revenues booked in Accounts 451, 454, 455, 562, 565 and 567.

The TSS is not aware that RSI has identified any Transmission Owner as Out of Compliance or in Partial Compliance with the Implementation Rule based on this suggested change. Again, by way of background, this provision of the Implementation Rule reflects the specific agreement of the settling parties that amounts to be utilized for this component of the formula were to be limited to the amounts booked to Account 454.

IMPLEMENTATION RULE: Section II.H(3) (Transmission Related Administrative and General Expenses)

This is an issue that was specifically identified with respect to NEP's FERC hydroelectric licensing fees. As set forth in FERC Form 1, Account Number 928 includes FERC assessment of expenses on a per megawatt hour basis and FERC assessment of expenses for hydroelectric generating plants. Section II.H(3) provides that total FERC assessments shall be multiplied by the Plant Allocation Factor. Accordingly, it is appropriate to include all Account 928 FERC assessments. The Implementation Rule does not require that a portion of the Account 928 FERC assessments be carved out or segregated before allocation as provided in Section II.H(3).

CALCULATION OF AVERAGE NETWORK LOAD

Although RSI did not specifically raise this as an issue, a potential question has arisen regarding the calculation of Network Load. Pursuant to Section 46.1 and the definitions of Local Network, Local Network Service, Monthly Network Load and Network Load in the Tariff and Attachment E to the Tariff, the term "Monthly Network Load" shall be the coincident peak of the transmission facilities constituting a "Local Network." The facilities constituting a "Local Network" are those facilities whose costs are recovered under a Local Network Service tariff.

APPLICATION OF THE IMPLEMENTATION RULE TO MUNICIPAL TRANSMISSION OWNERS

A number of issues were raised in the course of the RNS Audit regarding the interpretation and application of certain aspects of the Implementation Rule to MTOs. The TSS provides the following guidance to RSI with respect to those issues.

General Approach

As a general matter, the Implementation Rule was developed specifically and primarily for application to the IOTOs. That reflects nothing more than the fact that the focus of the dispute in the Tariff Docket, and hence the focus of the concern of the Settling Parties, was on Attachment F as it applied to IOTOs. The RNS Audit has revealed that application to the MTOs of the Implementation Rule will therefore require some flexibility in interpretation. As a general rule, it was not the intent of the Settling Parties, nor the purpose of the Implementation Rule, to preclude MTOs from recovering their PTF-related costs consistent with the intent and principles of Attachment F.

MTOs do not file FERC Form 1s or may not utilize the FERC's uniform system of accounts to the same extent as IOTOs. Accordingly, references in the Implementation Rule to FERC Form 1 and specific FERC accounts for purposes of determining various components of the Attachment F formula should not be read literally in applying the Implementation Rule to the MTOs. While the MTOs do not utilize FERC Form 1 and may not utilize the full range of specific FERC accounts identified in the Implementation Rule, they do make analogous periodic filings with their state regulatory agencies. Those regulatory filings, as well as independent audit reports performed for other purposes, are appropriate sources of data to develop the various components of the Attachment F formula for MTOs for purposes of the Implementation Rule.

Implementation Rule Section II.A.2 (Cost of Capital Rate)

RSI has raised a question with respect to calculation of the "Weighted Cost of Capital" with respect to an MTO, particularly concerning long term debt (Section II.2(a)(i)). For purposes of the RNS audit, the Weighted Cost of Capital for an MTO shall be a proxy of 8.00%, consistent with the requirements of applicable state law.

The Implementation Rule in Section II.2(a)(iii) defines for each IOTO a specific Return on Equity ("ROE"). RSI has reportedly suggested that NEPOOL define a specific ROE for each MTO in a similar manner. The specifically defined ROEs set forth for each IOTO in this Section of the Implementation Rule reflects a compromise of a number of interrelated issues in dispute in the Tariff Docket. Among other things, that compromise resolved a dispute with respect to whether there should be one uniform ROE applicable to NEPOOL or whether the individual ROE of each Transmission Owner was to be utilized in developing the Attachment F revenue requirements. The specific ROEs identified in the Rule reflect a compromise of that dispute, as well as compromises to resolve other disputes. Applying a similar concept to the MTOs would therefore not be appropriate.

Implementation Rule Section II.E (Municipal Tax Expense)

RSI has noted that some municipal systems pay property taxes whereas others make payments in lieu of taxes, and that in some cases: (a) the payment in lieu of taxes is related to earnings and (b) there is some discretion as to the amount that is paid or transferred to the municipality. RSI has proposed that a uniform rule be adopted in which a level of property tax is recognized as an expense with a cap based on the local property tax rates applied to the transmission facilities actually owned by the municipal utility. This recommendation reflects an approach utilized by some but not all of the MTOs. Since not all MTOs are similarly situated, a one-size-fits-all approach may not be appropriate, necessary or desirable. Accordingly, provided the MTO is using a traditionally accepted or recognized methodology and has adequate and verifiable supporting documentation, the MTO should be found in compliance with respect to this component of the Rule.

Implementation Rule: Section I.A.1 (Transmission Wages and Salaries Allocation Factor)

For the three years under audit, Holyoke Gas and Electric Department ("HGED") did not have any direct allocations for labor wages or salaries attributable to operations and maintenance for transmission. During the period being audited, another independent auditor focusing on Attachment F issues recommended to HGED that HGED's Transmission Wages and Salaries Allocation Factor should equal its Plant Allocation Factor. Although HGED did not necessarily agree with that approach, it nonetheless implemented it on the recommendation of the auditor. For the period beginning with calendar year 1999 data, HGED has directly assigned any transmission related direct wages and salaries (as well as operations and maintenance expenses) to transmission accounts. HGED notes that applying the 1999 data as a proxy for the period being audited will likely produce a more accurate result. The TSS concurs. Provided that HGED has appropriate supporting documentation, the 1999 data should be used as a proxy for the period audited since that will more closely reflect the purpose and intent of the Implementation Rule as applied to this particular MTO's circumstances.

Implementation Rule: Section II.G (Transmission Operation and Maintenance Expense)

Similar to the circumstance described above, for the three years under audit, HGED did not have its operation and maintenance expenses directly assigned for transmission. To arrive at the Transmission Operation Maintenance and Expense component, HGED multiplied the Plant Allocation Factor by all operation and maintenance supervision accounts. HGED then took that number and multiplied it by the PTF Transmission Plant Allocation Factor. This approach was utilized on the basis of the audit described in the prior section of this document. The TSS believes this is a reasonable proxy in the circumstances and conforms to the principles and intent of this component of the Rule given this MTO's circumstance. On a going forward basis, starting with the 1999 year, HGED has directly assigned all of the transmission operations and maintenance expenses to the proper account.

IMPLEMENTATION RULE: Section I.B. (Payroll Taxes)

This Section provides that the defined term Payroll Taxes shall equal those payroll expenses as recorded in the Transmission Provider's FERC Account Nos. 408.1 and 409.1. Two issues have arisen with respect to this Section. First the reference to FERC Account No. 409.1 is a mistake, since that is an account which captures income tax rather than payroll tax. The second issue again relates to application of this definition to an MTO which may not utilize these FERC system of accounting to the same extent as an IOTO. Accordingly, to resolve both of these issues, this component should be interpreted to apply to any FERC Account or other state-approved regulatory account in which payroll taxes are booked, and the focus of the audit should be a determination of whether there is adequate supporting documentation establishing that the amounts claimed by the Transmission Owner in fact reflect payroll taxes.

INTERPRETATION AND APPLICATION OF NABS 12

Section 5 of the Stipulation provides in pertinent part that NEPOOL is to make a compliance filing to implement the provisions of the Settlement Agreement and, as part of that compliance filing, is to file with the Commission a document identified in the Tariff Docket as Exhibit NPL-12, "which is that portion of the current NABS Procedure No. 12 used to determine transmission line, terminal facilities and right of way PTF investment." A copy of Exhibit NPL 12, which is the currently in effect version of Appendix B to NABS Procedure No. 12 is included as Attachment A to this document. For convenience, that document will be referred to herein in as "Current NABS 12."

Section 5 of the Stipulation reflects a compromise settling claims made by certain parties to the Tariff Docket that NEPOOL had never filed with the Commission the rules for determining PTF investment and could therefore change those rules without providing full and fair notice to Participants potentially affected by those changes. To settle those claims, NEPOOL agreed to file Current NABS 12 with the Commission, thereby preventing modifications to those rules absent an appropriate filing with and approval by the Commission.

On June 6, 1997, the NEPOOL Executive Committee approved what became the Current NABS 12 to become effective on June 1, 1998. Pursuant to the restructured NEPOOL arrangements, the Current NABS 12 would then apply to establish what comprises PTF for purposes of determining the Attachment F revenue requirement on a prospective basis commencing with the rates to become effective June 1, 1998. Accordingly, the Current NABS 12 applies only to the 1997 and 1998 test years, and does not apply to the 1996 test year. The version of NABS 12 in effect through May 31, 1998 ("Prior NABS 12") applies to the 1996 test year. Attachment B to this document shows the text of the Prior NABS 12.

It was not the intent of the settling parties that Current NABS 12 be applied retrospectively or be applied to any time period prior to its own effective date. Indeed, any attempt to do so would undo a complex set of compromises in the Settlement Agreement concerning a PTF reclassification, among other aspects of the compromises reached by the settling parties.

Use of the PTF Catalogs for Determining Transmission Line Status

On an annual basis, NEPOOL creates the PTF Catalog which is a comprehensive listing prepared by the NEPOOL Reliability Committee of all electric transmission lines identified as PTF in the period since the last PTF Catalog was issued. The PTF Catalog is typically issued in the Spring of a year and identifies the transmission lines that are designated PTF in the prior calendar year. To the extent that RSI needs to verify whether a piece of equipment is PTF, RSI should look to the appropriate PTF Catalog, rather NABS 12 Section A.

Issues With Respect to NABS 12 – Section B

RSI has asked for guidance on a number of very specific questions concerning the application of the rules for determining PTF investment with respect to terminal facilities reflected in Section B of Current NABS 12 (and, for the applicable years, Prior NABS 12). These questions require a determination as to whether specific pieces of equipment are properly identifiable as PTF or non-PTF. Making those determinations properly falls within the jurisdiction of the NEPOOL Reliability Committee ("RC"). The TSS has forwarded RSI's questions to the RC for discussion at the next RC meeting, scheduled for February 14, 2001. It is anticipated that NEPOOL will forward the RC's response to RSI's questions shortly thereafter.

RELIABILITY COMMITTEE FEBRUARY 13, 2001 RESPONSES TO PTF/NABS12 QUESTIONS

At its February 13, 2001 meeting, the Reliability Committee discussed and responded to a set of questions directed to it by the Transmission Settlement Subcommittee in connection with the audit being performed by Rhema Services, Inc. under ISO-NE's supervision, pursuant to Section 6 of the NEPOOL-Staff Stipulation.[1] The Reliability Committee's answers to the questions (which in certain cases were re-worded at the direction of the Committee for clarity), taking into account the years 1996, 1997 and 1998, were as follows:

(1) [Omitted.]

(2) Transmission service areas that are connected to the PTF network at a single network substation are normally viewed as radial, non-network transmission areas whether they are connected to the network substation by one, two or more lines. Transmission loops connected to the rest of the network from such a single substation bus do not provide a path for network flows. Should such equipment be considered PTF?

Answer: Because lines are involved, the PTF Catalog will be the governing document. If the line is in the PTF Catalog, the equipment is PTF.

(3) Under the situation described in (2), an issue arises when generation of more than 25 MW is located in an otherwise non-PTF area. If the entire area in question were owned by one utility that has no other PTF eligible facilities, the rules allow one of the two paths to the PTF network to be designated as PTF eligible. The rules do not address the situation of mixed ownership. Does the presence of 25 MW or more of generation owned by one utility result in only a single path through another utility to the network bus becoming PTF eligible? (B) Or does the presence of 25 MW or more of generation owned by one utility result in multiple paths through another utility system becoming PTF eligible that otherwise would not have been PTF eligible?

Answer: Because lines are involved, the PTF Catalog will be the governing document. If the line is in the PTF Catalog, the equipment is PTF.

(4) Can spare equipment, such as a spare 345 kV breaker or spare 345/115kV transformer, located in a substation but not used at this time be considered a PTF cost?

Answer: The Committee could not provide a definitive answer (split 5-4) with respect to the question as modified - whether or not spare equipment was a PTF cost.

---

[1] The NEPOOL-Staff Stipulation was part of the April 5, 1999 comprehensive settlement agreement (the "Settlement Agreement") reached Docket No. OA97-237-000, et al., and approved by the Commission, New England Power Pool, 88 FERC ¶ 61,140 (1999).

(5) Regarding equipment contained in a substation to accommodate addition of a future line or transformer. Should such equipment be considered PTF if it does not now provide a path for network flows?

Answer: No. However, it would qualify as PTF if it provides a parallel path flow.

(6) Should flow limiting reactors if operated normally bypassed, but capable of automatic insertion in a line to control flows in PTF facilities under certain operating conditions, be treated as PTF?

Answer: Yes.

(7) Should transmission level capacitor banks connected to a PTF eligible bus that may be normally operated open, but capable of being placed in service during adverse system conditions, be treated as PTF?

Answer: Yes.

(8) Should transmission level capacitor banks that are connected to the PTF by radial lines be treated as PTF?

Answer: A majority of the Committee answered No.

(9) Can a linebe PTF eligible if it is normally operated open but can be closed during adverse system conditions?

Answer: The PTF Catalog controls whether a line is PTF eligible for the period in question.

(10) Should transmission lines and equipment that loop with external ties be treated as PTF?

Answer: A majority of the Committee answered Yes.

MEMORANDUM

TO: Alan Jackman, Acting Director of Audits, ISO-NE

FROM: Scott P. Myers

DATE: May 29, 2001

RE: Additional Guidance Provided by Reliability Committee With Respect to Interpretation of Rules for Determining PTF Investment

---

During the course of the audit, an additional issue has arisen regarding interpretation of the Rules for Determining PTF Investment. Following our prior procedure, the issue was submitted to the Reliability Committee for guidance. The issue was framed as follows:

> Should transformer-related costs, such as installation and other related costs that would not have been incurred but for the transformer, be treated in the same manner as the transformer for purposes of determining the allocation of common under these rules?

The Reliability Committee considered this issue at its May 17, 2001 meeting and answered as follows:

> YES, if such costs have been identified in association with the transformer. However, if such installation or other related transformer costs are not separately identifiable, then no additional accounting effort is expected for this purpose.

Please contact me if you need additional information regarding this memorandum.

cc: Paul Shortley
Reliability Committee Members and Alternate Members
Marc Guerrette
NEPOOL Transmission Settlement Subcommittee

ISO New England Inc.
RNS Rate Audit for 1996, 1997 and 1998
Request For Information

1). Provide for the years 1996, 1997 and 1998 the electronic version of the Revenue Requirement template used in calculating the TRR filed with ISO-NE (include all formulas and/or computations).

2). Provide all work-papers utilized or developed in the preparation of all inputs or formulas employed in the Revenue Requirement template.

3). Provide system one-line diagram(s) depicting in detail all interconnections, transmission lines, substations and other equipment operating at transmission voltages of 69 KV and above. Provide the latest revision made to these one-line diagrams for each of the years ending 12/31/96, 12/31/97 and 12/31/98.

4). For each full or partially allocated PTF and year ending 12/31/96, 12/31/97 and 12/31/98, provide:

A). A one-line diagram for each transmission station/substation depicting the equipment allocated to PTF.
B). A list of all station/substation facilities and associated equipment allocated to PTF.
C). For each station/substation facility listed in B) above provide the following information:
i). A one line diagram of each facility;
ii). The total gross plant dollars invested in the facility;
iii). The total dollars allocated to PTF for each facility; and
iv). The detailed work-papers and source documents showing the dollars allocation to PTF.
D). A list of all transmission lines, poles, and associated equipment allocated to PTF.
E). Repeat C) for D) above.

5). Identify all right-of-way costs assigned to PTF and any allocation methodology employed when allocating between PTF and non-PTF facilities for the years 1996, 1997 and 1998.

6). For 1996, 1997 and 1998, provide from original cost accounting records by station/substation and transmission lines all facilities included in each FERC transmission account (Accounts 350 through 359).

7). For 1996, 1997 and 1998, provide a list of Transmission Plant Held for Future Use and designated use by voltage level.

8). Beginning with January 1996 through December 1998, provide the system Coincident Monthly Peaks for Local Network Service before and after any adjustments for A) losses, B) Firm Internal Point to Point Service, and C) Firm Through and Out of Service, if applicable.

9). Beginning with January 1996 through December 1998, for each monthly Firm Point to Point Service and monthly Firm Through and Out Service transaction referenced in 8) B) and C) above, provide A) the Long Term Reserved Capacity amounts (including actual Service Agreements) and B) the actual coincident peaks (coincident with the Coincident Monthly Peaks for Local Network Service) for each transaction.

NEPOOL RNS RATE AUDIT REPORT

Appendix F

Audit Findings Matrix

19-Apr-02

Prepared by Rhema Services Inc.

RNS Audit Report
Audit Findings Matrix
1996

						Com Electric System			Connecticut Municipal				Eastern Utilities Association							Northeast Utilities								
		Bangor Hydro Electric Company	Boston Edison Company	Braintree Electric Light Department	Central Maine Power Company	Commonwealth Edison Company	Canal	Cambridge	Wallingford	Groton	Norwich	Bozrah	Blackstone Valley Electric Company	Eastern Edison Company	Montaup Electric Company	Newport Electric	Fitchburg Gas & Electric	Holyoke Gas & Electric	New England Power	Connecticut Light & Power	Holyoke Power & Electric	Holyoke Water Power Company	Public Service Company of New Hampshire	North Atlantic Energy Corp.	Western Massachusetts Electric Co.	Taunton Municipal Lighting Plant	United Illuminating	Vermont Electric Power Company
	Audit Exceptions to PTF & Non-PTF																											
1	PTF vs. Non PTF Determination	O	O	O		O	O		N/A	N/A	N/A	N/A	O	O	O	O	O	O	O	O		O	O	O	O	O	O	O
	Audit Exceptions to RNS Inputs																											
2	ROR Calculation	O	O	O	O				N/A	N/A	N/A	N/A	O	O	O	O		O		O		O	O	O	O	O	O	O
3	Wages & Salaries								N/A	N/A	N/A	N/A	O	O		O			O									
4	Payroll Taxes			O		O	O		N/A	N/A	N/A	N/A					O									O	O	
5	Property Taxes	O	O						N/A	N/A	N/A	N/A						O								O	O	O
6	Materials & Supplies			O					N/A	N/A	N/A	N/A	O	O												O		
7	Prepayments			O					N/A	N/A	N/A	N/A						O								O		
8	Depreciation								N/A	N/A	N/A	N/A					O											
9	Regulatory Comm. Expenses	O	O			O			N/A	N/A	N/A	N/A					O									O		
10	Transmission Plant								N/A	N/A	N/A	N/A														O		
11	General Plant								N/A	N/A	N/A	N/A																
12	Property Insurance								N/A	N/A	N/A	N/A						O										
13	Accumulated Depreciation								N/A	N/A	N/A	N/A						O										
14	Account #561 & A&G Expenses								N/A	N/A	N/A	N/A						O										
15	Account # 562,565 &/or 567& Other O&M		O						N/A	N/A	N/A	N/A					O	O								O		O
16	Plant Held For Future Use								N/A	N/A	N/A	N/A					O											
17	Accumulated Deferred Taxes	O							N/A	N/A	N/A	N/A																
18	Other Regulatory Assets/Liabilities	O							N/A	N/A	N/A	N/A					O											O
19	FAS 106 &/or 109								N/A	N/A	N/A	N/A																
20	Loss on Reacquired Debt								N/A	N/A	N/A	N/A						O										
21	Account # 454 &/or 456								N/A	N/A	N/A	N/A			O													O
22	Plant Allocation Factor		O			O	O		N/A	N/A	N/A	N/A						O										
23	Transmission Support Revenue	O																										
24	Average Regional Network Load								N/A	N/A	N/A	N/A																

LEGEND; O=The Auditor has concluded that the TO revenue requirement submission to ISO NE was not in compliance with the requirements of the Controlling Document.
As noted in the Executive Summary, all Transmission Owners have since submitted a revenue requirement that the Auditors have concluded is in compliance with the Controlling Document and Interpretative Guidance Document.

RNS Audit Report
Audit Findings Matrix
1997

						Com Electric System			Connecticut Municipal				Eastern Utilities Association							Northeast Utilities								
		Bangor Hydro Electric Company	Boston Edison Company	Braintree Electric Light Department	Central Maine Power Company	Commonwealth Edison Company	Canal	Cambridge	Wallingford	Groton	Norwich	Bozrah	Blackstone Valley Electric Company	Eastern Edison Company	Montaup Electric Company	Newport Electric	Fitchburg Gas & Electric	Holyoke Gas & Electric	New England Power	Connecticut Light & Power	Holyoke Power & Electric	Holyoke Water Power Company	Public Service Company of New Hampshire	North Atlantic Energy Corp.	Western Massachusetts Electric Co.	Taunton Municipal Lighting Plant	United Illuminating	Vermont Electric Power Company
	Audit Exceptions to PTF & Non-PTF																											
1	PTF vs. Non PTF Determination	O	O	O		O	O		N/A	N/A	N/A	N/A	O	O	O	O	O	O	O	O		O	O	O	O	O	O	O
	Audit Exceptions to RNS Inputs																											
2	ROR Calculation	O	O	O	O				N/A	N/A	N/A	N/A	O	O	O	O		O		O		O	O	O	O	O	O	O
3	Wages & Salaries								N/A	N/A	N/A	N/A	O	O		O			O									
4	Payroll Taxes			O		O			N/A	N/A	N/A	N/A														O	O	
5	Property Taxes	O	O		O				N/A	N/A	N/A	N/A						O								O	O	O
6	Materials & Supplies			O					N/A	N/A	N/A	N/A	O	O												O		
7	Prepayments			O					N/A	N/A	N/A	N/A						O								O		
8	Depreciation		O						N/A	N/A	N/A	N/A					O	O										
9	Regulatory Comm. Expenses	O							N/A	N/A	N/A	N/A					O									O	O	
10	Transmission Plant								N/A	N/A	N/A	N/A														O		
11	General Plant								N/A	N/A	N/A	N/A																
12	Property Insurance								N/A	N/A	N/A	N/A						O										
13	Accumulated Depreciation		O						N/A	N/A	N/A	N/A																
14	Account #561 & A&G Expenses				O				N/A	N/A	N/A	N/A						O										
15	Account # 562,565 &/or 567 & Other O&M		O						N/A	N/A	N/A	N/A					O	O								O		O
16	Plant Held For Future Use								N/A	N/A	N/A	N/A					O											
17	Accumulated Deferred Taxes	O							N/A	N/A	N/A	N/A								O			O		O			
18	Other Regulatory Assets/Liabilities	O							N/A	N/A	N/A	N/A					O											O
19	FAS 106 &/or 109								N/A	N/A	N/A	N/A																
20	Loss on Reacquired Debt								N/A	N/A	N/A	N/A						O										
21	Account # 454 &/or 456								N/A	N/A	N/A	N/A			O													O
21	Plant Allocation Factor		O			O	O		N/A	N/A	N/A	N/A						O										
22	Transmission Support Revenue	O																										
23	Average Regional Network Load								N/A	N/A	N/A	N/A																

LEGEND; O=The Auditor has concluded that the TO revenue requirement submission to ISO NE was not in compliance with the requirements of the Controlling Document. As noted in the Executive Summary, all Transmission Owners have since submitted a revenue requirement that the Auditors have concluded is in compliance with the Controlling Document and Interpretative Guidance Document.

RNS Audit Report
Audit Findings Matrix
1998

						Com Electric System			Connecticut Municipal				Eastern Utilities Association							Northeast Utilities								
		Bangor Hydro Electric Company	Boston Edison Company	Braintree Electric Light Department	Central Maine Power Company	Commonwealth Edison Company	Canal	Cambridge	Wallingford	Groton	Norwich	Bozrah	Blackstone Valley Electric Company	Eastern Edison Company	Montaup Electric Company	Newport Electric	Fitchburg Gas & Electric	Holyoke Gas & Electric	New England Power*	Connecticut Light & Power	Holyoke Power & Electric	Holyoke Water Power Company	Public Service Company of New Hampshire	North Atlantic Energy Corp.	Western Massachusetts Electric Co.	Taunton Municipal Lighting Plant	United Illuminating	Vermont Electric Power Company
	Audit Exceptions to PTF & Non-PTF																											
1	PTF vs. Non PTF Determination	O	O	O		O	O		O	O	O	O	O	O	O	O		O	O	O		O	O	O	O	O	O	O
	Audit Exceptions to RNS Inputs																											
2	ROR Calculation	O	O	O	O		O		O	O	O	O	O	O	O	O		O	O	O		O	O	O	O	O	O	O
3	Wages & Salaries									O	O	O	O	O		O			O									
4	Payroll Taxes			O	O					O	O	O							O							O	O	
5	Property Taxes	O							O	O	O	O						O	O							O	O	O
6	Materials & Supplies			O						O	O	O	O	O					O							O		
7	Prepayments			O					O		O	O						O	O							O		
8	Depreciation								O	O	O	O						O	O									
9	Regulatory Comm. Expenses	O					O				O	O					O		O								O	
10	Transmission Plant										O	O						O	O							O		
11	General Plant									O	O	O						O	O									
12	Property Insurance										O	O						O	O									
13	Accumulated Depreciation					O			O	O	O	O							O									
14	Account #561 & A&G Expenses									O	O	O						O	O									
15	Account # 562,565 &/or 567 & Other O&M		O							O	O	O					O	O	O							O		O
16	Plant Held For Future Use										O	O					O		O									
17	Accumulated Deferred Taxes	O									O	O							O									
18	Other Regulatory Assets/Liabilities	O									O	O					O		O									O
19	FAS 106 &/or 109										O	O							O									
20	Loss on Reacquired Debt										O	O			O			O	O									
21	Account # 454 &/or 456										O	O			O				O									O
21	Plant Allocation Factor		O			O	O			O	O	O				O		O	O									
22	Transmission Support Revenue	O																										
23	Average Regional Network Load										O	O																

LEGEND; O=The Auditor has concluded that the TO revenue requirement submission to ISO NE was not in compliance with the requirements of the Controlling Document.
As noted in the Executive Summary, all Transmission Owners have since submitted a revenue requirement that the Auditors have concluded is in compliance with the Controlling Document and Interpretative Guidance Document.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Office of Markets, Tariffs and Rates

New England Power Pool
Docket No. ER02-145-000

Day, Berry & Howard LLP
City Place I
Hartford, CT 06103-3499

Issued: November 20, 2001

Attention: Scott P. Myers
Counsel for New England Power Pool Participants Committee

Reference: Seventy-Seventh Agreement Amending New England Power Pool Agreement and various non-substantive changes to Attachment F of the NEPOOL Tariff.

Ladies and Gentlemen:

New England Power Pool's (NEPOOL) submittal is accepted for filing. The designations and effective date are listed on the Enclosure.

On October 22, 2001, you filed with the Commission a Seventy-Seventh Agreement Amending New England Power Pool Agreement. The filing updates and makes non-substantive corrections of provisions within the NEPOOL Tariff. You request that the revision be made effective January 1, 2002.

This filing was noticed on October 9, 2001, with comments due on October 23, 2001. No adverse comments were filed.

This action is taken pursuant to the authority delegated to the Director, Division Tariffs and Rates - East, under 18 C.F.R. 375.307.

This acceptance for filing shall not be construed as constituting approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service contained in your filing; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such action is without prejudice to any findings or orders which have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against your company.

011123-0050-1

DOCKETED
BL

Docket No. ER02-21-000 -2-

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. 385.713.

Sincerely,

FCR

Alice Fernandez, Director
OMTR/Tariffs and Rates - East

Enclosure

New England Power Pool
ER02-145-000
Tariff Designation
Effective Date: January 1, 2002

Designation		Description
(1)	FERC Electric Tariff Fourth Revised Vol. No. 1 First Revised Sheet Nos. 218, 268, 271, 274, 275, 286, 287, 703, 704, 706, and 708 replacing Original Sheet Nos. 218, 268, 271, 274, 275, 286, 287, 703, 704, 706, and 708. Original Sheet Nos. 712-721	NEPOOL Open Access Transmission Tariff Corrections.

ORIGINAL

DAY, BERRY & HOWARD LLP

Counsellors at Law
Hartford, Stamford, Greenwich and Boston

CityPlace I
Hartford
Connecticut 06103-3499
Telephone (860)275-0100
Facsimile (860)275-0343
Internet www.dbh.com

Scott P. Myers
(860) 275-0361
Internet spmyers@dbh.com

FILED
OFFICE OF THE SECRETARY
01 OCT 22 AM 11:40
FEDERAL ENERGY
REGULATORY COMMISSION

October 19, 2001

VIA OVERNIGHT MAIL

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission ER02-145-000
888 First Street, N.E.
Washington, D.C. 20426

Re: New England Power Pool - FERC Docket No. ER02- -000
Seventy-Seventh Agreement Amending New England Power Pool Agreement;
Amendments to the Attachment F Implementation Rule

Dear Secretary Boergers:

Pursuant to Section 205 of the Federal Power Act, the New England Power Pool ("NEPOOL") Participants Committee[1] hereby files an original and six (6) copies of this transmittal letter, the Seventy-Seventh Agreement Amending New England Power Pool Agreement (the "Seventy-Seventh Agreement"), which is Attachment 1 to this filing, and additional supporting materials. The Seventy-Seventh Agreement proposes non-substantive corrections of, and updates to, certain provisions of the NEPOOL Tariff, primarily reflecting recently completed merger activity among various NEPOOL Participants. Also included in this filing are changes to the implementation rule for Attachment F of the NEPOOL Tariff (the "Implementation Rule"). The Implementation Rule has previously been filed as a supplement to the NEPOOL Tariff, and the amendments being submitted are non-substantive corrections of erroneous references in certain defined terms in the Implementation Rule, as well as updates to certain other terms to reflect changes in NEPOOL's committee structure.

A copy of the revised sheets of the NEPOOL Tariff reflecting the Seventy-Seventh Agreement is included as Attachment 2 hereto. A copy of the revised sheets to the

---

[1] Capitalized terms used but not defined in this transmittal letter and referenced materials are intended to have the same meaning given to such terms in Sections 1 and 6 of the Restated New England Power Pool Agreement ("Restated NEPOOL Agreement" or "Agreement") or Section 1 of the Restated NEPOOL Open Access Transmission Tariff ("NEPOOL Tariff" or "Tariff").

OSEC

011025-0059-1

DOCKETED

Implementation Rule reflecting the changes described in this filing is included as Attachment 4 hereto. NEPOOL requests that the Commission accept these changes to become effective on January 1, 2002, which is the beginning of the first calendar month sixty days after the date of this filing.

I. AMENDMENTS TO THE NEPOOL TARIFF EFFECTED BY THE SEVENTY-SEVENTH AGREEMENT

The Seventy-Seventh Agreement amends the following provisions of the NEPOOL Tariff for the reasons set forth below.

Tariff Sheet No.	Purpose of Correction
218	Corrects an erroneous reference to "Year Six" in Section 4 of Schedule 9 of the Tariff, which sets forth the methodology for determining the pre-1997 Participant RNS Rate charged under the Tariff.
268	Amends the language of Attachment E to the Tariff to reflect the merger of New England Electric System with National Grid plc and with Eastern Utilities Associates.
271	The End Date of the Excepted Transaction in Line Item 9 of Attachment G is amended to reflect the terms of the merger between New England Electric System and Eastern Utilities Associates.
274-275	The entity identified as the "Provider" in several of the Excepted Transactions identified on these pages of Attachment G is amended to reflect the merger of Eastern Utilities Associates with New England Electric System.
286-287	The entity identified as the "Provider" in several of the Excepted Transactions identified on these pages of Attachment G is amended to reflect the merger of Eastern Utilities Associates with New England Electric System.

These changes are not substantive and will not increase or decrease the rates charged under the NEPOOL Tariff.

II. AMENDMENTS TO THE ATTACHMENT F IMPLEMENTATION RULE

On December 31, 1996, NEPOOL filed a comprehensive restructuring proposal which included the Restated NEPOOL Agreement and the NEPOOL Tariff. The justness and reasonableness of various provisions of the NEPOOL Tariff, including the provisions in

Attachment F which concern the determination of the annual revenue requirements of the Participants with respect to Pool Transmission Facilities, was set for hearing pursuant to the Commission's April 20, 1998 order, New England Power Pool, 83 FERC ¶61,045 (1998) (the "April 20 Order"), in Docket Nos. OA97-237-000, ER97-1079-006, ER97-3574-005, OA97-608-005, ER97-4421-005 and ER98-499-004 (the "Tariff Docket"). The issues raised in that proceeding were addressed in the April 5, 1999 Comprehensive Agreement Resolving All Issues Raised in this Proceeding Except for One Issue Raised by Great Bay Power Company (the "Settlement Agreement") reached by the parties.

The Settlement Agreement provided for certain changes to Attachment F and for the filing of the Implementation Rule, a detailed rule for implementing Attachment F. The Settlement Agreement, including the revised Attachment F and the Implementation Rule, was approved by the Commission in New England Power Pool, 88 FERC ¶61,140 (1999) (the "July 30 Order").

This filing makes non-substantive corrections to various provisions of the Implementation Rule. These changes will not result in an increase or decrease in the rates charged under the NEPOOL Tariff. Those corrections are described below:

Sheet No.	Purpose of Correction
703	The amendment to the definition of "Payroll Taxes" in Section I.B of the Implementation Rule corrects an erroneous reference to a FERC Account.
703	The amendment to the definition of "PTF Transmission Plant Investment" in Section I.B of the Implementation Rule updates that definition to correctly reflect the location within NEPOOL's filed rate documents of the "Rules for Determining Investment to be Included in PTF."
704	The amendment to the definition of "Total Municipal Tax Expense" in Section I.B of the Implementation Rule corrects an erroneous reference to a FERC Account.
706	The definition of "Transmission Prepayments" in Section II.A.1(f) of the Implementation Rule is amended to correct a cross-reference to another defined term in the Rule.
708	The references to Commonwealth Electric Company, Eastern Utilities Associates, and New England Electric System in Section II.A.2(a)(iii)(1) of the Implementation Rule are updated to reflect recently completed merger activities involving all of these entities.

In addition to these changes, NEPOOL in this filing is also designating the "Rules for Determining Investment to be Included in PTF" (the "PTF Rules") as a new Appendix A to the Implementation Rule. To resolve a disputed issue in the Tariff Docket, NEPOOL agreed to file with the Commission as a supplement to the Tariff the then-current version of the PTF Rules.[2] The purpose of filing the PTF Rules was to assure that the PTF Rules would be easily accessible to parties interested in examining them, and to further assure that the PTF Rules could not be changed without a Section 205 filing made with the Commission.

In compliance with the July 30 Order approving the Settlement Agreement, NEPOOL on September 27, 1999 filed the PTF Rules as a supplement to the Tariff. For clarity and convenience, NEPOOL at this time is resubmitting the PTF Rules as a new Appendix A to the Implementation Rule. This is consistent with the initial intent of the Participants reflected in the definition of "PTF Transmission Plant Investment" in Section I.B of the Implementation Rule, which references the PTF Rules as an attachment to the Implementation Rule.

NEPOOL has not altered the text of the PTF Rules from the version that was approved by the Commission in the July 30 Order as part of the Settlement Agreement, with the exception of the following non-substantive corrections and updates of certain defined terms to reflect, in part, changes in the NEPOOL governance structure that took effect after the Settlement Agreement had been filed. Those corrections and updates are as follows:

1. Sheet No. 713: insert the word "Restated" before the phrase "New England Power Pool Agreement;" capitalize the "t" in the word "Transmission" as it appears in the phrase "New England transmission network";

2. Sheet No. 714: delete the reference to "Regional Transmission Planning Committee" and replace it with the name of the successor committee; clarify reference to Section 18.4 of the Restated NEPOOL Agreement;

3. Sheet No. 716: delete the reference to "Management Committee" and replace it with the name of the successor committee;

4. Sheet No. 717: correct the term "R/W" in numbered paragraph 2; and

5. Sheet No. 718: delete the reference to "NEPOOL Executive Committee" and replace it with the name of the successor committee.

These changes are non-substantive and will not result in an increase or decrease in the rates charged under the NEPOOL Tariff.

---

[2] The agreement regarding the filing of the PTF Rules is reflected in Section 5 of the February 12, 1999 stipulation between NEPOOL and Commission Trial Staff (the "Stipulation") which was designated as an attachment to the Settlement Agreement.

NEPOOL respectfully requests that the Commission approve the amendments to the Implementation Rule, including the PTF Rules, as proposed herein effective January 1, 2002.

III. ADDITIONAL SUPPORTING INFORMATION

The non-substantive updates and corrections set forth in this filing will not increase rates. In further support of this filing, NEPOOL submits the following information pursuant to Section 205 of the Federal Power Act and Section 35.13 et seq. of the Code of Federal Regulations:

35.13(b)(1) - Materials included herewith are as follows:

- This transmittal letter;
- The Seventy-Seventh Agreement Amending New England Power Pool Agreement. (Attachment 1);
- Revised sheets of the NEPOOL Tariff reflecting all changes made by the Seventy-Seventh Agreement (Attachment 2);
- Relevant sections of the NEPOOL Tariff marked to show all of the changes made by the Seventy-Seventh Agreement to prior versions of the NEPOOL Tariff on file with the Commission (Attachment 3);
- Revised sheets of the Implementation Rule, including the PTF Rules, reflecting changes made by this filing (Attachment 4);
- Relevant sections of the Implementation Rule marked to show all of the changes made by this filing to the prior version of the Implementation Rule on file with the Commission (Attachment 5);
- A list of NEPOOL Participants Committee members and alternates and Non-Participant Transmission Customers (Attachment 6);
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent (Attachment 7); and
- A draft form of notice, suitable for publication in the Federal Register (Attachment 8), and a diskette containing this form of notice.

35.13(b)(2) - No waiver of the Commission's notice requirement is requested with respect to the changes proposed in this filing. It is requested that the Seventy-Seventh Agreement and Implementation Rule changes described herein be permitted to become effective on January 1, 2002 or such date as the Commission shall provide in its order.

35.13(b)(3) - Attachment 6 to this transmittal letter shows the names and addresses of all Participants, which include all of the electric utilities rendering or receiving services under the Restated NEPOOL Agreement, as well as each of the independent power producers, power marketers, power brokers, load aggregators, customer owned utility systems and end users that are currently Participants in NEPOOL. All Participants have been furnished with a copy of this filing, together with this transmittal letter and the accompanying materials.[3] This transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the NEPOOL Control Area, and to the New England Conference of Public Utilities Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 7. In accordance with Commission rules and practice, there is no need for the entities identified on Attachments 6 and 7 to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in this transmittal letter.

35.13(b)(6) - The changes proposed in this filing have been approved by the NEPOOL Participants Committee. Actions by the NEPOOL Participants Committee regarding amendments to the NEPOOL Tariff must be approved by an affirmative vote equal to, or in excess of, two-thirds of the aggregate Sector Voting Shares, provided the Minimum Response Requirement of the Restated NEPOOL Agreement has been satisfied. The Seventy-Seventh Agreement was unanimously approved in balloting. The changes to the Implementation Rule, including the PTF Rules, were unanimously approved by the Participants Committee at its July 13, 2001 meeting. Balloting of those changes was not required. The NEPOOL Transmission Owners Committee unanimously approved the Seventy-Seventh Agreement and the changes to the Implementation Rule included in this filing at its October 10, 2001 meeting.[4]

35.13(b)(7) - NEPOOL has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

---

[3] Pursuant to changes to Section 21.13 (e) of the Restated NEPOOL Agreement which was accepted by the Commission in New England Power Pool, 90 FERC ¶ 61,019 (2000), NEPOOL Participants are being served electronically rather than by hard copy.

[4] The issue of the locus of unilateral filing rights pursuant to Section 205 with respect to transmission-related provisions of the Restated NEPOOL Agreement and the NEPOOL Tariff is the subject of dispute which is reserved pursuant to Section 17A.7 of the Restated NEPOOL Agreement. Nothing in this submittal is intended to express, assert or concede any position on behalf of any NEPOOL Participant or group of Participants (including the NEPOOL Participants Committee and the NEPOOL Transmission Owners Committee) as to the reserved issue.

35.13(b)(8) - Submitted with this transmittal letter as Attachment 8 is a draft form of notice concerning this filing that is suitable for publication in the Federal Register in accordance with Section 35.8 of the Commission's Regulations. A diskette containing this form of notice is also enclosed.

35.13(c)(1) - The amendments in this filing will not result in any increase in rates.

35.13(c)(2) - The Participants do not jointly provide services under other rate schedules that are similar to the wholesale for resale and transmission services jointly provided by them under the Restated NEPOOL Agreement.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in order to supply service under the Seventy-Seventh Agreement.

Correspondence and communications regarding this filing should be addressed to the Chair of the Participants Committee, and the undersigned as follows:

Daniel W. Allegretti, Chair
NEPOOL Participants Committee
c/o Enron Corp.
2 Capital Plaza
Concord, NH 03301
Tel: (603) 223-0985
Fax: (603) 224-7601
e-mail: daniel.allegretti@enron.com

David T. Doot
Scott P. Myers
Day, Berry & Howard LLP
CityPlace I
Hartford, CT 06103-3499
Tel: (860) 275-0361
Fax: (860) 275-0343
e-mail: spmyers@dbh.com

Please acknowledge receipt of this filing by date stamping and returning the extra copy of this transmittal letter in the enclosed pre-posted, pre-addressed envelope.

Very truly yours,
New England Power Pool Participants Committee

Scott P. Myers
Its Counsel

cc: Entities identified in Attachments 6 and 7

General Plant Depreciation Expense shall equal the Transmission Provider's general expenses as recorded in FERC Account No. 403.

General Plant Depreciation Reserve shall equal the Transmission Provider's general reserve balance as recorded in FERC Account No. 108.

Hydro-Quebec DC Facilities (HQ Leases) shall equal the Transmission Provider's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

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

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

Payroll Taxes shall equal those payroll expenses as recorded in the Transmission Provider's FERC Account Nos. 408.1 ~~and 409.1~~.

Plant Held for Future Use shall equal the Transmission Provider's balance in FERC Account No. 105.

Prepayments shall equal the Transmission Provider's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the Transmission Provider's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant Investment shall equal the Transmission Provider's transmission plant as defined in the Section 15.1 of the Restated NEPOOL Agreement and determined in accordance with ~~Attachment 1.5~~ Appendix A of this ~~rule~~ Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance as recorded in FERC Account Nos. 281-283 and the deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the Transmission Provider's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the Transmission Provider's municipal tax expenses as recorded in FERC Account Nos. 408.1~~, 409.1~~.

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

Total Transmission Depreciation Reserve shall equal the Transmission Provider's transmission reserve balance as recorded in FERC Account 108.

Transmission Operation and Maintenance Expense shall equal the Transmission Provider's expenses as recorded in FERC Account Nos. 560, 562-564 and 566-573, and shall exclude all HQ HVDC expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the Transmission Provider's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the Transmission Provider's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the Transmission Provider's (A) Return and Associated Income Taxes, (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) Transmission Related Integrated Facilities

Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF Transmission Plant Allocation Factor.

(e) Transmission Related Accumulated Deferred Taxes shall equal the Transmission Provider's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF Transmission Plant Allocation Factor.

(f) Transmission Related Loss on Reacquired Debt shall equal the Transmission Provider's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF Transmission Plant Allocation Factor.

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

(h) Transmission Prepayments shall equal the Transmission Provider's electric balance of prepayments multiplied by the Transmission Wages and Salaries ~~allocator~~ Allocation Factor and further multiplied by the PTF Transmission Plant Allocation Factor.

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

(j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent

Bangor Hydro-Electric Company	11.5%
Boston Edison Company	10.65%
Central Maine Power Company	11.00%
Commonwealth Energy System companies, formerly known as Commonwealth Electric Company	10.75%
Eastern Utilities Associates (as of June 1, 2001, with the New England Electric System, referred to as the National Grid USA copanies included in the NEPOOL Control Area; per action of the NEPOOL TSS June 28, 2000)	11.22% (through May 31, 1999) 10.65% (beginning June 1, 1999)
New England Electric System (as of June 1, 2001, with Eastern Utilities Associates, referred to as the National Grid USA companies included in the NEPOOL Control Area; per action of the NEPOOL TSS June 28, 2000)	10.65%
The United Illuminating Company	11.5% (through May 31, 1999) 10.75% (beginning June 1, 1999)
Vermont Electric Company	11.50%
Northeast Utilities	11.75%

(2) For each year during the period commencing June 1, 2000, the return on equity component shall be determined in the same manner, and the allowed ROE for each Transmission Provider identified above shall remain in effect for purposes of such determination for the Provider until an amendment to its cost of service under the Local Network Service Tariff for the Provider filed after December 31, 1999 results in a different allowed ROE for that Provider, in which case that Provider's ROE shall be set for purposes of such determination at the ROE ultimately determined to be just and reasonable in the proceeding involving the applicable Local Network Service Tariff amendment.

APPENDIX A

RULES FOR DETERMINING INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines

Section B – Terminal Facilities

Section C – Right of Way

Effective June 1, 1998

~~FERC Dockets OA97-237-000, et al.~~
~~Exhibit NPL-12~~

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF), under the Restated New England Power Pool Agreement, are the transmission facilities owned by Participants rated 69 kV or above required to allow energy from significant power sources to move freely on the New England ~~T~~transmission network, and include:

1. All ~~T~~transmission lines rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

    c. lines that are normally operated open.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a Participant with significant generation in its system (initially 25 MW) is connected to the New England network and none of the transmission facilities owned by the ~~p~~Participant qualify to be included in PTF as defined in "1" and "2" above, then such Participant's connection to PTF will constitute PTF if both of the following requirements are met:

    a. The connection is rated 69 kV or above.

    b. The connection is the principal transmission link between the Participant and the remainder of the New England PTF network.

    The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the Participant's system.

4. R/W and land required for the installation of PTF facilities listed in "1", "2", or "3" (see Section C).

The following examples indicate the intent of the above definitions:

a. Radial tap lines to local load are excluded.

b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.

c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.

e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.

f. Where multiple circuit structures support a mixture of PTF and non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The ~~Regional Transmission Planning~~ Reliability Committee will review, at least annually, the status of facilities PTF to determine whether any such facilities should be terminated or others added because of change in use.

All new facilities being installed should be properly classified at the time the facilities are approved under Section 18.4 of the Agreement.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is non-PTF.

3. Where line terminals are installed solely for non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a non-PTF function shall be excluded. The investment in land, structures, ground

mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and non-PTF functions served by these facilities.

12. The ~~Management~~ Participants Committee may designate appropriate facilities as PTF.

Section C: Rules for Determining PTF R/W Costs

1. If a R/W has only PTF lines and no non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.

2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by non-PTF lines, the cost of the additional R/~~w~~W is not to be included as PTF.

3. If the R/W contains both PTF and non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:

    a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).

    b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.

    c. Where a R/W is widened, but the new facilities, either PTF or non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.

4. In allocating R/W between PTF and non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

    a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.

    b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.

5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the ~~NEPOOL Executive~~ Participants Committee included under paragraph 1.

REMINDER: ADDITIONAL PAGES ARE DIAGRAMS THAT SHOULD BE INCLUDED W/ THIS DOCUMENT; DOCUMENT IS NOT COMPLETE WITHOUT ADDITIONAL PAGES.

ISO New England, Inc.

REQUEST FOR PROPOSAL FOR
REGIONAL NETWORK SERVICE RATE AUDIT

TABLE OF CONTENTS

1 INTRODUCTION

ISO New England, Inc. (ISO-NE) solicits bids to perform an audit of the Regional Network Service (RNS) annual rates in effect for the three-year periods of:

- June 1, 1997 through May 31, 1998
- June 1, 1998 through May 31, 1999
- June 1, 1999 through May 31, 2000

These three annual rates are based on calendar year data for 1996, 1997 and 1998, respectively. The results of the three audits will be delivered to ISO-NE in the form of a written report. The results of these audits will also be filed as an informational filing with the Federal Energy Regulatory Commission (FERC) pursuant to Section 6 of the NEPOOL/FERC Staff Stipulation, which was included in a comprehensive settlement agreement approved by FERC in a July 30, 1999 order in NEPOOL Dockets OA97-237-000, et al. As stated in that stipulation, "***Such audit(s) shall verify, through such sampling as appropriate, that Transmission Providers are correctly accounting for Pool Transmission Facilities (PTF) investment in accordance with the applicable NEPOOL rules for determining PTF investment. The results of any such audit(s) shall be filed with the Commission as an informational filing, and the charges recalculated to correct any errors identified in such audit, with refunds and surcharges, as appropriate, for any amounts previously over- or under-charged due to such errors.***" The applicable New England Power Pool (NEPOOL) rules for determining PTF investment are set forth in the NEPOOL Open Access Transmission Tariff (OATT)-Attachment F, included in this document as Appendix B and in the Implementation Rule for Calculating Annual Transmission Revenue Requirements," (the "Implementation Rule"), included in this document as Appendix C.

Many of the documents referenced within this RFP are available on the ISO-NE website at *www.iso-ne.com.* Acronyms utilized throughout this RFP are summarized and defined in Appendix A. Each of the capitalized terms used throughout this RFP, if not defined within this RFP, shall have the meaning as set forth within the definition sections of the Restated

NEPOOL Agreement (RNA), NEPOOL OATT, NEPOOL Market Rules and Procedures (MRPs), and NEPOOL Operating Procedures (OPs) as appropriate.

2 GENERAL OVERVIEW

The following sections are provided to give the prospective bidders some background information on ISO-NE and its operations. Additionally, a brief description of ISO-NE responsibilities is included, along with a description of the general process to be followed in conducting the audits.

2.1 DESCRIPTION OF ISO-NE

ISO-NE is a not-for-profit, non-stock Delaware corporation responsible for directing the operation and control of New England's electric bulk power system and administering the region's wholesale electricity marketplace and the NEPOOL OATT, and is a jurisdictional utility subject to regulation by the FERC. Prior to ISO-NE's formation, NEPOOL, a voluntary association of New England utilities, directed the operation of the region's bulk generating and transmission facilities for twenty-seven years, maintaining reliability standards and coordinating cost-effective electric generation and transmission for the region's six million electric consumers. As the region's electric restructuring efforts unfolded as a result of the Federal Energy Policy Act of 1992 (EPAct), NEPOOL proposed that a new independent entity, one not affiliated with the NEPOOL Participants (Participants), be created to administer the restructured wholesale markets for its members. This entity was intended to promote strong competition and marketplace efficiency in accordance with the Independent System Operator (ISO) concept proposed by the FERC in Order No. 888.

On July 1, 1997, ISO-NE assumed control of the bulk power system in New England and on May 1, 1999, began operating the NEPOOL wholesale electricity markets.

ISO-NE is managed by an independent Board of Directors with a broad range of expertise in financial markets, utility operations and regulation. An Advisory Committee comprised of individuals from all six New England states representing academia, government and private business provides input to the ISO-NE Board of Directors regarding the maintenance of a reliable, independent, competitive and fair electricity marketplace.

For additional information about ISO-NE, please see the ISO-NE website under the "About ISO" information tab. Additionally, a copy of the 1998 annual report for ISO-NE is available on the website home page.

2.2 RESPONSIBILITIES OF ISO-NE

The responsibilities of ISO-NE with regard to the reliable operation of the New England Power Pool and operation of the competitive wholesale markets in New England are defined within an Interim Independent System Operator Agreement (ISO Agreement) which was executed between ISO-NE and NEPOOL and approved by the FERC. ISO-NE's primary responsibilities include:

a) control area operations for the NEPOOL control area and operation of the NEPOOL system control center in accordance with the RNA, the NEPOOL OATT, the MRPs, the OPs, Good Utility Practice and applicable laws and regulations

b) administration of the NEPOOL OATT and the wholesale competitive markets in accordance with the RNA, the MRPs, the OPs, Good Utility Practice and applicable laws and regulations

c) ensuring short-term reliability of the system consistent with the applicable standards set by the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC)

d) develop, maintain and operate an Open Access Same-time Information System (OASIS) consistent with the requirements of applicable laws and regulations

e) coordinate the restoration of service in the event of a system shutdown.

For additional information about the responsibilities of ISO-NE, please see the RNA (45th Amendment) and the ISO Agreement, both of which are available through the ISO-NE website. Additionally, current versions of the MRPs and OPs are also available through the ISO-NE website.

2.3 RESPONSIBILITIES OF TSS

The NEPOOL Transmission Settlement Subcommittee (TSS), which reports to the NEPOOL Regional Transmission Operations Committee (RTOC), is responsible for the annual updates to, and reviews of, the RNS rates charged under the NEPOOL OATT. The RNS rate charged for the regional transmission service in New England is based upon the total Revenue Requirements for PTF owned and operated by the New England Participants. PTF includes those transmission facilities rated 69kV and above which allow for power sources to move freely on the New England transmission network. The Revenue Requirements for non-PTF are collected through the local transmission tariffs of the individual Participants, and are outside the scope of this audit. The PTF Revenue Requirements for the Participants are calculated based upon the formula and rules as stipulated in the NEPOOL OATT, Attachment F (included in this document as Appendix B) and the Implementation Rule (included in this document as Appendix C).

2.4 PROCESS FOR CONDUCTING THE AUDIT

The overall objective of the audit is to assure that the NEPOOL PTF rate and the Transmission Providers' RNS rates are accurately computed in conformance with the applicable documents. To assist in the conduct of an efficient and effective audit engagement, each of the transmission owners and supporters will assign a "point person" to facilitate the retrieval of the necessary supporting documentation. The audit should include on site visits at the twelve transmission owners' locations to further expedite the process. The vendor may, at its discretion, deem it necessary to conduct on site visits, on a test basis, at the transmission supporters' locations. The audit will be managed by ISO-NE, and both ISO-NE and TSS members will assist the auditor as necessary.

3 DESCRIPTION OF MAJOR COMPONENTS TO BE AUDITED

The three major components comprising the annual RNS rate development are described below.

3.1 RNS REVENUE REQUIREMENT

The Transmission Revenue Requirements reflect each Participant's costs to maintain and operate the PTF. The NEPOOL OATT-Attachment F contains the formula to calculate these Annual Transmission Revenue Requirements. The NEPOOL OATT-Attachment F also defines the proper accounting treatment and definition of the specific items included in the formula. The rules for determining Transmission Investment costs to be included in the PTF accounts are described in the Implementation Rule. The Transmission Revenue Requirement annual calculation for a given year is based upon the previous calendar year data as reported on the FERC Form 1 and other supporting documentation. For example, 1997 calendar year data is used to compute the RNS rate for the period June 1, 1998 through May 31, 1999.

3.2 NEPOOL RNS MODEL

The NEPOOL RNS Model provides a mechanism for ISO-NE to summarize the Participant data and calculate the total New England Revenue Requirement for PTF. The major steps in this calculation are as follows:

- From the input submitted by the Participants, ISO-NE enters the Annual Transmission Revenue Requirement data into the NEPOOL Regional Transmission Group (RTG) Worksheet.
- Each Transmission Provider also submits its monthly coincidental peak network load, which is input to the twelve-month coincidental peak network load used in the calculation of the RNS rate.
- Once all the data has been received from each of the Participants, ISO-NE enters all the information in the NEPOOL RNS Model which automatically calculates the NEPOOL PTF rate and the Transmission Providers' RNS rates for the year.

3.3 PTF COST ACCOUNTING

The Implementation Rule documents the proper accounting and allocation method to record the PTF/non-PTF costs. The accounting method utilized by each Participant directly impacts the Annual Transmission Revenue Requirement reported to ISO-NE and the RNS rate calculated in the NEPOOL RNS Model.

4 AUDIT SCOPE AND DELIVERABLES

The following sections provide an overview of the audit scope along with an identification of the deliverables required of the vendor. As stated earlier, the overall objective of the audit is to assure that the NEPOOL PTF rate and the Transmission Providers' RNS rates are accurately computed in conformance with the applicable documents. The Participants recovering the PTF costs through the NEPOOL RNS rate include not only the twelve Participants that own PTF but also the thirty-three Participants that do not own but support certain PTF.

4.1 SCOPE

The scope of this audit shall encompass the following tasks:

a) **RNS Revenue Requirement:**

Verify that each Participant's costs for PTF agree with their FERC Form 1, and other supporting documentation, and meet the requirements of NEPOOL OATT-Attachment F and the Implementation Rule. For all owners and non-owners of PTF, the data submitted should conform with the intent and principles of the NEPOOL OATT-Attachment F and FERC Form 1.

b) **NEPOOL RNS Model:**

For each Participant, verify, through such sampling as appropriate, the calculation of the twelve monthly coincidental peak network loads and their proper inclusion in the NEPOOL RNS Model. For each Participant, verify that the Annual Transmission Revenue Requirement amount in the NEPOOL RNS Model agrees with the data submitted by the Participant. For each Participant, verify the clerical accuracy and that the data submitted to ISO-NE on the input documents agrees with appropriate supporting documentation.

c) **PTF Cost Accounting:**

Verify, through such sampling as appropriate, that each Participant's PTF/non-PTF allocation of transmission plant or substation (as listed in the NEPOOL PTF Catalog), used to develop each Company's PTF Allocation Factor, conforms to the accounting methods described in the Implementation Rule. The NEPOOL PTF Catalog can be found under the "Transmission" tab on the ISO-NE external web page at www.iso-ne.com. The sample selected should be representative of all the transmission plant costs including substations classified 100% PTF, classified 100% Non-PTF and substations classified with both PTF/Non-PTF.

The evaluation is to be completed under Consulting Standards promulgated by the American Institute of Certified Public Accountants (AICPA). Results of the evaluation process should be presented as follows:

a) **In Compliance**, where "In Compliance" means the reported data and the RNS rate calculation have substantially met all of the requirements of the RNA, NEPOOL OATT-Attachment F and the Implementation Rule.

b) **Partial Compliance**, where "Partial Compliance" means that some inconsistencies were noted between the reported data, and/or the RNS rate calculation relative to the requirements of the RNA, NEPOOL OATT-Attachment F and the Implementation Rule.

c) **Out of Compliance,** where "Out of Compliance" means that significant inconsistencies were noted between the reported data, and/or the RNS rate calculation relative to the requirements of the RNA, NEPOOL OATT-Attachment F and the Implementation Rule.

As previously mentioned, this evaluation shall encompass accuracy of data, recalculation of formulas and information exchange between processes and timeliness of communications. Where processes are evaluated as being in "Partial Compliance" or "Out of Compliance", the vendor shall report the basis of such evaluation.

4.2 Deliverables

The vendor shall provide a draft report to ISO-NE management, which will include a detailed description of all processes audited and the findings. ISO-NE will review the draft report and discuss with the vendor any required changes. The vendor will then prepare a final report which ISO-NE and the vendor will present to the TSS. See Section 7.2 for the delivery dates of the reports.

5 SUBMISSION REQUIREMENTS

The following items must be included as part of a bidder's response to this RFP:

a) Cover letter stating the bidder's full name, address, and, if applicable, the branch office that would perform the work and designated persons authorized to act on behalf of the bidder during final contract negotiations and execution of the RNS Audit Agreement;

b) Executive summary of proposal;

c) Relevant experience (include reference contacts):

- Industry
- Transmission services pricing
- Tariff rates

d) Proposed team including individual profiles (include contact name and e-mail address for further correspondence);

e) Proposal for meeting the audit scope, including a detailed work plan for accomplishing the audits that includes the following:

1) A schedule for achieving the goals in Sections 4.1 and 4.2 above, including time, cost estimates, milestones and disclosing any assumptions made,

2) The bidder's proposed project organization chart, and

f) The bidder's earliest start date, assuming the vendor selection and notification by February 24, 2000;

g) Project Price and Engagement fees:

Payment will be at an agreed upon hourly rate (the "Contract Rate") with the total payment for the audit not to exceed a maximum amount ("Project Price"). Bidder shall provide the proposed Project Price, which shall encompass the items in (e) above in the following detail:

1) The categories of staffing to be provided and the proposed Contract Rate per hour for each category,

2) Total estimated travel expenses providing detail as set forth below both in total dollars and per diem/per mile assumptions:

Lodging:	__________
Subsistence (meals):	__________
Mileage:	__________
Car rental:	__________
Other:	__________

3) Total estimated cost of supplies and materials, plus a master suitable for reproduction, of the final RNS Rate Audit Report,

4) Any other direct costs, such as telephone, fax, copying and other charges, expected to be reimbursed, at a rate not to exceed 100% of actual out-of-pocket costs incurred,

5) Any general administrative overhead costs expected to be charged back and the proposed rate/method of allocation;

h) Revisions to RNS Audit Agreement:

A form of the proposed RNS Audit Agreement has been attached to this RFP as Appendix D. The bidder must provide all desired revisions to the RNS Audit Agreement, if any, as part of its Response to the RFP on February 10, 2000. The bidder should be prepared to execute the RNS Audit Agreement, as proposed to be revised, if selected by ISO-NE. Therefore, all proposed revisions should be submitted in the form of insertions or deletions, rather than as narrative comments, although explanatory comments accompanying proposed revisions would be acceptable. Attaching the bidder's form contract or form terms and conditions to replace the RNS Audit Agreement as a whole, or the draft terms and conditions set forth in the RNS Audit Agreement in their entirety, by way of proposed "revision", will be deemed to be non-responsive and will result in disqualification of bidder; and

i) Any other relevant information. Clarity and brevity should be observed, however.

6 EVALUATION CRITERIA

ISO-NE may, in its sole discretion, decline to accept or evaluate any proposals received from prospective bidders after the deadline stated in Section 7.1 (Submission Deadline).

Each proposal should cover the information requested in Section 5 (Submission Requirements) in sufficient detail to permit accurate evaluation of the proposal. Material that is not germane to this RFP is not desired. Emphasis should be on brevity, completeness and clarity of content. It is mandatory that proposals contain the signature of an officer or agent of the bidder duly empowered to execute such a document. Proposals without such a signature will not be considered.

ISO-NE will make the final selection of the successful bidder. Selection will be made based on the ISO-NE's evaluation of the proposals and assessment of the respondents' ability to meet the ISO-NE's needs. Each bidder must be able to demonstrate that it meets the AICPA standards for independence and ethics.

Selection criteria are as follows:

a) professional expertise and experience of the Auditor and its assigned staff as it relates to the subject matter of this RFP, including expertise in tariff rates, transmission services, and availability of suitable references;

b) the bidder's ability to start and complete the Audit in a timely manner while ensuring stability of assigned staff;

c) proposed Project Price, Contract Rates and other costs detailed in response to Section 5 and any revisions proposed to the RNS Audit Agreement, attached as Appendix D to this RFP with preference given to proposals that offer a fixed price service; and

d) responsiveness to this RFP, including thoroughness and specificity of the work plan developed for the audit.

Proposals shall be complete in all respects as outlined in Section 5 (Submission Requirements). A proposal may be rejected if it is conditional, incomplete, or contains any alteration of form or any irregularities of any kind that could materially change the prices in the bidder's proposal.

7 TIMELINE AND CONTACT INFORMATION

7.1 SUBMISSION DEADLINE

The mandatory submission deadlines are listed below:

- Clarifying questions must be submitted via E-mail no later than 4:00 p.m. EST on January 25, 2000.
- ISO-NE will make every effort to respond to all questions to the extent possible. The responses to clarifying questions shall be provided to all bidders via E-mail no later than 4:00 pm EST on February 1, 2000.
- Bidders must submit five (5) sealed copies in writing of their proposal by 1:00 p.m. EST on February 10, 2000. Electronic copies of proposals should be made available via E-mail attachment upon request.
- The target date for vendor selection is February 24, 2000.

7.2 AUDIT TIMEFRAME AND DELIVERABLE DATES

- A draft report for the 1996, 1997 and 1998 calendar year data audit should be issued to ISO-NE by September 1, 2000.

- A final audit report for the 1996, 1997 and 1998 calendar year data should be issued to ISO-NE by October 20, 2000.

7.3 Contact Information

All clarifying questions regarding this RFP, or any ambiguity, omission or error discovered in this RFP should be noted and submitted via E-mail to Alan C. Jackman at ISO-NE. All sealed proposals should be mailed to :

Mr. Alan C. Jackman
ISO New England, Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Phone: 413-535-4167
Fax: 413-535-4083/4084
E-Mail: ajackman@iso-ne.com

8 CONFIDENTIALITY

All information disclosed in this document is confidential and may be used by the Recipient only for the purpose of evaluating whether the Recipient desires to submit a response to this RFP. Therefore, no information contained in this RFP may be disclosed, reproduced, copied, duplicated or disseminated, as a whole or in part, for any purpose other than preparing a Proposal, without the prior written consent of ISO-NE.

By acceptance of this RFP, each bidder agrees not to release advertising or publicity matter pertaining to this RFP and/or any proposals resulting therefrom or pertaining to the performance of the services for the RNS Rate Audit, without prior written approval of ISO-NE.

A proposal may include proprietary data that the bidder does not want disclosed to the public or used by ISO-NE for any purpose other than proposal evaluation. Unless proprietary data are identified, however, ISO-NE cannot assume responsibility for the use of such data. Therefore, proprietary data should be specifically identified as such on every page where the same may be contained, in which event it will be used by ISO-NE or its designated representatives, including staff and consultants, solely for the purpose of evaluating the proposal. In such cases, reasonable care will be exercised so that the data, so identified, will not be disclosed or used without the bidder's permission except to the extent provided in any resulting contract or the extent required by law. This restriction does not limit ISO-NE's right to use or disclose any data contained in the proposal if they are obtainable from another source, or were obtained from the bidder on a previous occasion without restriction.

9 WITHDRAWAL OF RFP/REJECTION OF PROPOSAL

It is ISO-NE's policy not to solicit proposals unless there is a *bona fide* intention to award a contract. ISO-NE reserves the right to withdraw this RFP at any time, however, and to accept or reject any or all proposals received as a result of this RFP.

10 LIMITATIONS

This RFP does not commit ISO-NE to award the RNS Audit Agreement to or to be responsible or liable in any manner for any risks, costs or expenses incurred by any bidder in the preparation of a proposal in response to this RFP or any revision of such a proposal.

ISO-NE may undertake or award other contracts for additional or related work, and the Vendor shall fully cooperate with other contractors and ISO-NE employees and carefully fit its work to such additional work as may be required. The successful vendor agrees, by submission of a Response, that it shall not commit or permit any act which will interfere with the performance of work by any other contractor or by employees of the representatives or members of ISO-NE.

The successful vendor may not hire a subcontractor to perform the services for the RNS Rate Audit.

11 CHANGE OF OWNERSHIP

In the event that the successful vendor should change ownership for any reason whatsoever, ISO-NE shall have the exclusive option of continuing under the terms and conditions of the

Agreement, or continuing under the terms and conditions of the Agreement with the successful vendor or its successors or assigns for such period of time as is necessary to replace the successful vendor's services, or immediately terminating the Agreement.

12 NONDISCRIMINATION CLAUSE

The successful vendor shall not discriminate against any employee, applicant for employment, independent contractor or any other person because of race, color, religious creed, ancestry, national origin, age, or sex.

The successful vendor shall comply with all state and federal laws prohibiting discrimination in hiring or employment opportunities. In the event of the successful vendor's noncompliance with this provision or with any such laws, the Agreement may be terminated or suspended, as a whole or in part, and the successful vendor may be declared temporarily ineligible for further ISO-NE contracts, and other sanctions may be imposed and remedies invoked.

The successful vendor shall furnish all necessary employment documents and records to, and permit access to its books, records, and accounts by ISO-NE for purposes of investigation to ascertain compliance with the provisions of this RFP. If the successful vendor does not possess documents or records reflecting the necessary information requested, it shall furnish such information on reporting forms supplied by ISO-NE.

APPENDIX A – ACRONYMS

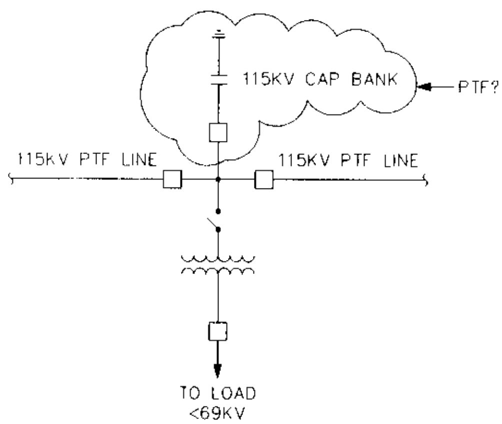
1.	**AICPA**	American Institute of Certified Public Accountants
2.	**ATC**	Available Transmission Capability
3.	**FERC**	Federal Energy Regulatory Commission
4.	**ISO**	Independent System Operator
5.	**ISO-NE**	ISO New England, Inc.
6.	**ISO Agreement**	Interim Independent System Operator Agreement
7.	**MRP**	NEPOOL Market Rules and Procedures
8.	**NEPOOL**	New England Power Pool
9.	**NERC**	North American Electric Reliability Council
10.	**NPCC**	Northeast Power Coordinating Council
11.	**OASIS**	Open Access Same-time Information System
12.	**OATT**	Open Access Transmission Tariff
13.	**OP**	NEPOOL Operating Procedures
14.	**PTF**	Pool Transmission Facilities
15.	**RFP**	Request for Proposal
16.	**RNA**	Restated NEPOOL Agreement through the 42^{nd} Amendment
17.	**RTG**	Regional Transmission Group
18.	**RTOC**	NEPOOL Regional Transmission Operations Committee
19.	**TSS**	NEPOOL Transmission Settlement Subcommittee

ADDITIONAL GUIDANCE DOCUMENT FOR RNS AUDIT

In response to an issue that has arisen in the audit, the following question was presented to the Reliability Committee for guidance.

Under the Rules for Determining PTF Investment in effect for the 1996 test year, is the capacitor bank in the following illustration PTF or Non-PTF?

VELCO SUBSTATION
CONFIGURATION A



At its August 2001 meeting, the Reliability Committee provided the following answer: PTF.

ADDITIONAL REQUEST FOR GUIDANCE SUBMITTED TO THE RELIABILITY COMMITTEE WITH RESPECT TO RNS AUDIT

At its October 16, 2001 meeting, the Reliability Committee reviewed the following questions regarding the Rules for Determining PTF Investment (the "PTF Rules"). For convenience, the pertinent provisions of the PTF Rules are set forth below.

Section A, Paragraph 3 of the PTF Rules defines PTF to include:

> "Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B)."

Section B of the PTF Rules states that:

> "Terminal Investments is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7)."

Paragraph 7 of Section B of the PTF Rules states that:

> "Other facilities: The investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station excluding transformers, which are not identifiable as serving either a PTF or a non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance."

Paragraph 8 of Section B states that:

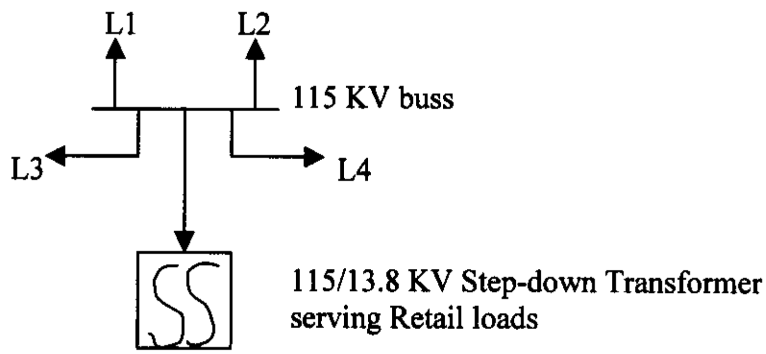
> "Alternative method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and the utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and non-PTF according to the number of terminals serving PTF and non-PTF facilities."

The Committee's response to the four (4) questions asked was as follows:

Question 1: What is the relationship between Paragraphs 7 and 8 of Section B of the PTF Rules?

Committee Response: Paragraph 7 is the preferred method when identified facilities and costs exist. If 51% or more of the costs of the total station are lumped and are not common but rather are specific to PTF or Non-PTF functions, then the method in Paragraph 8 should be used for making the allocation.

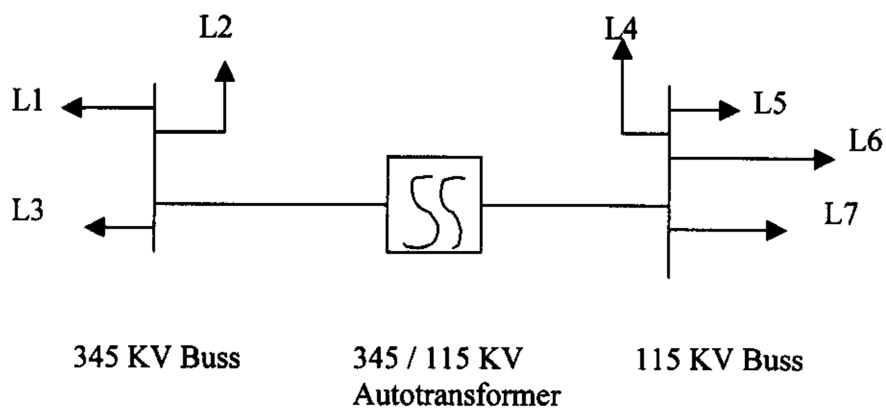
Question 2: Does the term "line terminal" as used in Section B of the PTF Rules refer to the termination points of PTF and Non-PTF transmission lines and the feeds to distribution step-down transformers that include isolation equipment (i.e., circuit breakers, airbreak or disconnect switches)?



Where L1, L2 and L4 are 115 KV PTF Lines
L3 is 115 KV Non-PTF Line

Committee Response: The transformer in the above configuration should be considered a terminal if it includes isolating equipment. The term "line terminal" is not used in Section B of the PTF Rules, and the Committee interpreted the quoted term to mean "terminal."

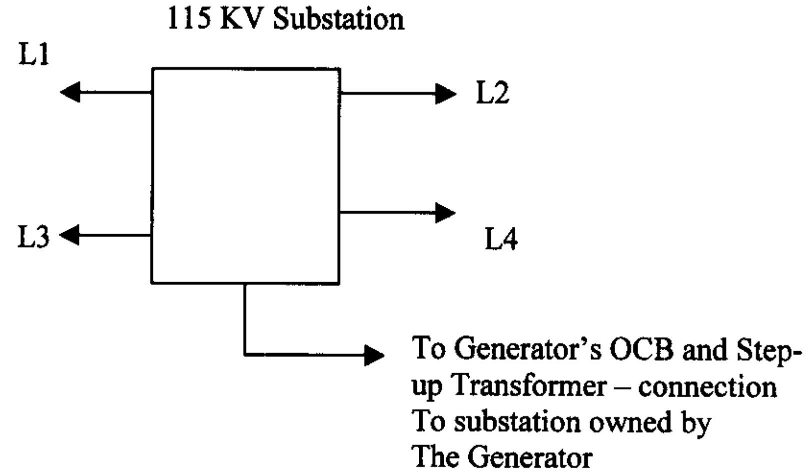
Question 3: Within a substation that has different PTF voltage busses (e.g., 345 kV and 115 kV) that serve both transmission lines and distribution step-down transformers, should the terminals of an autotransformer connecting the two PTF voltage busses be included in the "terminal count" for the purpose of determining the number of PTF and the number of total terminals served by that substation?



Lines L1, L2 and L3 345 KV PTF Lines
Lines L4, L5 and L7 115 KV PTF Lines
Line L6 115 KV Non-PTF Line

Committee Response: In the above illustration, the terminals of the autotransformer that connect to PTF busses are both terminals for the purpose of determining the number of PTF and the number of total terminals served by that substation. Thus, there is a total of nine terminals in the above illustration; eight PTF and one Non-PTF.

Question 4: In determining the PTF terminal count and total terminal count for a substation, should the connection points for generation/load facilities be included in the count where the interconnection equipment is solely owned by the interconnecting party?



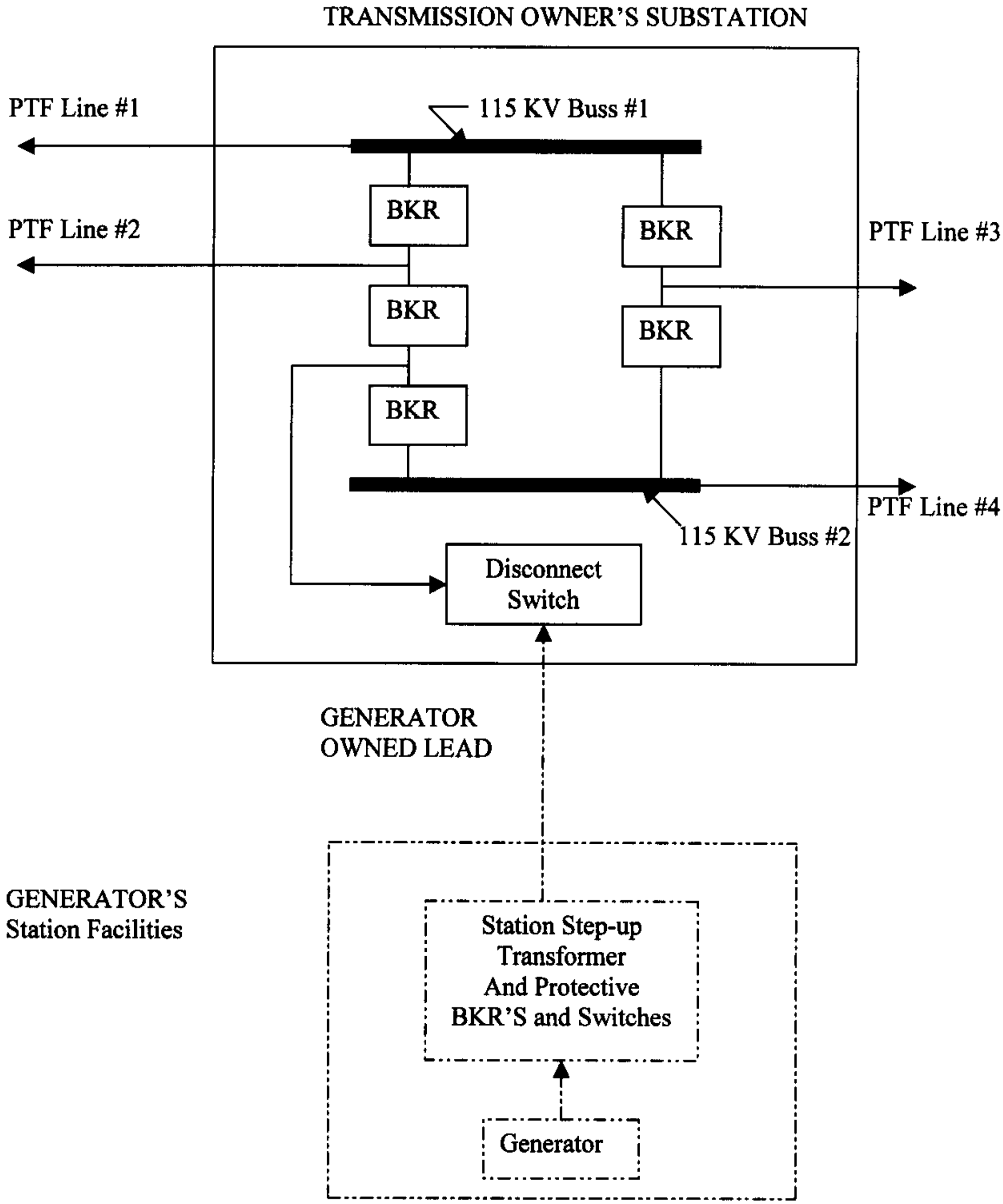
L1, L2, L3 and L4 are PTF 115KV Lines

Response: Using the above diagram, if the connection point is a load lead, it is a terminal. Based on the diagram and the information presented to the Committee, the Committee could not reach a consensus as to whether the connection point is or is not a terminal if the connection point is a generator lead.

At its December 4, 2001 meeting, the Transmission Settlement Subcommittee ("TSS") reviewed the Reliability Committee's response to question four (4) above as to the status of a connection point where the connection point is a generator lead (i.e., the underlined language above), and approved the following motion:

> RESOLVED, that the TSS recommends to the Reliability Committee that the connection points where the interconnection equipment is solely owned by the interconnecting generator would not be counted as a terminal for purposes of Paragraph 8 of Section B of the Rules for Determining Investment to be Included in PTF (the "PTF Rules") as set forth in Appendix A to the Attachment F Implementation Rule to the NEPOOL Tariff.

For further clarification, the diagram initially submitted to the Reliability Committee was refined as follows to show breakers.


TRANSMISSION OWNER'S SUBSTATION
PTF Line #1
115 KV Buss #1
PTF Line #2
BKR
BKR
PTF Line #3
BKR
BKR
BKR
PTF Line #4
115 KV Buss #2
Disconnect Switch
GENERATOR OWNED LEAD
GENERATOR'S Station Facilities
Station Step-up Transformer And Protective BKR'S and Switches
Generator

NEPOOL Participants Committee
Members and Alternates

April 19, 2002

Carrie Cullen Hitt
AES NewEnergy, Inc.
530 Atlantic Avenue, 5th Floor
Boston, MA 02210

Peter W. Brown (Alt.)
AES NewEnergy, Inc.
c/o Brown, Olson & Wilson, P.C.
501 South Street
Concord, NH 03304

Joseph Limone
Director & Senior Counsel
Allegheny Energy Supply Company, LLC
909 Third Avenue, 33rd Floor
New York, NY 10022

Laurie K. Peddicord (Alt)
Contract Administrator
Allegheny Energy Supply Company, LLC
909 Third Avenue, 33rd Floor
New York, NY 10022

James A. Shrewsbury
Energy Trader
American Electric Power Service Corporation
One Riverside Plaza
14th Floor
Columbus, OH 43215

Mike Evans (Alt)
Energy Trader
American Electric Power Service Corporation
One Riverside Plaza
14th Floor
Columbus, OH 43215

Dorothy J. Capra
Director Regulatory Affairs
ANP Marketing Company
65 Boston Post Road
Suite 300
Marlborough, MA 01752

William Henson (Alt)
Director, Power Marketing
ANP Marketing Company
65 Boston Post Road
Suite 300
Marlborough, MA 01752

Kevin J. Fox
Portfolio Manager & Vice President
Aquila Energy Marketing Corporation
1100 Walnut, Suite 3300
Kansas City, MO 64106

Peter W. Brown (Alt)
Attorney
Aquila Energy Marketing Corporation
c/o Brown, Olson & Wilson, P.C.
501 South Street
Concord, NH 03304

Stanley W. Herriott
Manager
Ashburnham Municipal Light Plant
78 Central Street
P.O. Box 823
Ashburnham, MA 01430

Roger W. Bacon (Alt)
Ashburnham Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert Ruddock
Executive Vice President
Associated Industries of Massachusetts
Suite 1300
222 Berkeley Street
Boston, MA 02117

Angela M. O'Connor
Vice President of Energy Programs
Associated Industries of Massachusetts
13th Floor
222 Berkeley Street
Boston, MA 02117

Frederick S. Samp
Vice President, Finance & Law
Bangor Hydro-Electric Company
33 State Street
P.O. Box 932
Bangor, ME 04402-0932

Jeffrey A. Jones (Alt)
Manager, Power Supply
Bangor Hydro-Electric Company
33 State Street
P.O. Box 932
Bangor, ME 04402-0932

Timothy L. McCarthy
Manager
Belmont Municipal Light Department
450 Concord Avenue
Belmont, MA 02478

Roger W. Bacon (Alt)
Belmont Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Thomas E. Atkins
Executive Vice President
Berkshire Power Development
c/o Power Development Company, LLC
440 Commercial Street
Boston, MA 02109

Ken Roberts Jr. (Alt)
Berkshire Power Development
c/o Power Development Company, LLC
2 Rockwell Street
Niantic, CT 06357

Ellen K. Angley
Vice President, Energy Supply and
Transmission
Boston Edison Company
c/o NSTAR
800 Boylston Street, P1603
Boston, MA 02199-8001

Robert P. Clarke (Alt)
Director, Energy Planning and Supply
Boston Edison Company
c/o NSTAR
800 Boylston Street (P1704)
Boston, MA 02199-8001

H. Bradford White, Jr.
Manager
Boylston Municipal Light Department
Paul X. Tivnan Road
P.O. Box 753
Boylston, MA 01505-0753

Roger W. Bacon (Alt)
Boylston Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert Scavone
BP Energy Company
501 WestLake Park Boulevard
Houston, TX 77079

Yehudah Rose (Alt)
BP Energy Company
501 WestLake Park Boulevard
Houston, TX 77079

Laurie J. Heffron
Electric Operations Manager
Braintree Electric Light Department
150 Potter Road
Braintree, MA 02184-3598

John P. Coyle (Alt)
Braintree Electric Light Department
c/o Duncan & Allen
1575 Eye Street, NW
Washington, DC 20005-1175

NEPOOL Participants Committee
Members and Alternates

April 19, 2002

Tom Kaslow
Calpine Energy Services, LP
c/o Calpine Eastern Corporation
The Pilot House, 2nd Floor
Lewis Wharf
Boston, MA 02110

Jeff Woodall (Alt)
Lead Scheduler
Calpine Energy Services, LP
700 Louisiana Ave., Ste. 2700
Houston, TX 77002

Margaret Downey
Asst. County Administrator
Cape Light Compact, The
3195 Main Street
P.O. Box 427
Barnstable, MA 02630

Robert Bigelow (Alt)
Cape Light Compact, The
P.O. Box 165
Woods Hole, MA 02543

John Trimble
Business Development Manager
Cargill-Alliant, LLC
12700 Whitewater Drive
Minnetonka, MN 55343-9439

Gaston Garrido (Alt)
Trading Manager
Cargill-Alliant, LLC
12700 Whitewater Drive
Minnetonka, MN 55343-9439

Eric N. Stinneford
Manager, Power Contracts Administration
Central Maine Power Company
41 Anthony Avenue
Augusta, ME 04330

Hariph M. Smith (Alt)
Central Maine Power Company
41 Anthony Avenue
Augusta, ME 04330

Jeffrey R. Cady
Power Resource Manager
Chicopee Municipal Lighting Plant
725 Front Street
P.O. Box 405
Chicopee, MA 01021-0405

Brian Forshaw
Chicopee Municipal Lighting Plant
c/o Connecticut Municipal Electric Energy
Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

John Ambrose
Senior Director
CinCap V, LLC
10 Crossroads Drive
Suite 200
Owings Mills, MD 21117

Michael G. Newman (Alt)
Operations Manager
CinCap V, LLC
1100 Louisiana, Suite 4950
Houston, TX 77002-5222

Ronald B. Johnson
CMS Marketing Services and Trading
1021 Main Street
Suite 2800
Houston, TX 77002-6606

Steven D. Guy (Alt)
Director of Origination
CMS Marketing Services and Trading
1021 Main Street
Suite 2800
Houston, TX 77002-6606

Daniel J. Sack
Superintendent
Concord Municipal Light Plant
1175 Elm Street
P.O. Box 1029
Concord, MA 01742-1029

NEPOOL Participants Committee
Members and Alternates

April 19, 2002

Roger W. Bacon (Alt)
Concord Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Marj Garbini
Transmission Engineer
Conectiv Energy Supply, Inc.
P.O. Box 6066
Newark, DE 19714-6066

Bill Fehr (Alt)
Power Trading Manager
Conectiv Energy Supply, Inc.
P.O. Box 6066
Newark, DE 19714-6066

Lawrence G. Union, Jr.
CEO & General Manager
Connecticut Energy Cooperative, Inc.
151 New Park Ave.
Hartford, CT 06106

Paul B. Popinchalk (Alt)
Director Energy Services
Connecticut Energy Cooperative, Inc.
151 New Park Ave.
Hartford, CT 06106

Brian E. Forshaw
Director
Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Maurice R. Scully (Alt)
Executive Director
Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Ken Bekman
Director, Wholesale Power
Consolidated Edison Energy, Inc.
701 Westchester Avenue
Suite 320E
White Plains, NY 10604

Michael Forte (Alt)
General Manager
Consolidated Edison Energy, Inc.
4 Irving Place, Room 1349S
New York, NY 10003

Harvey J. Reed
Managing Director
Constellation Power Source, Inc.
111 Market Place
Suite 500
Baltimore, MD 21202

Daniel W. Allegretti (Alt)
Constellation Power Source, Inc.
One Essex Drive
Bow, NH 03304

Robert Reilley
Vice President-Regulatory Affairs
Coral Power, LLC
909 Fannin Street
Suite 700
Houston, TX 77010

Coleen O'Brien-Pitts
Electric Utility Director
Danvers Electric Division
One Burroughs Street
Danvers, MA 01923-2702

Francis M. Gaffney (Alt)
Power Supply Engineer
Danvers Electric Division
One Burroughs Street
Danvers, MA 01923-2702

Ray Wieszczyk
Manager of Operations
DTE Energy Trading, Inc.
101 N. Main Street
Suite 300
Ann Arbor, MI 48104

Anthony Wisely (Alt)
Retail Trader
DTE Energy Trading, Inc.
101 N. Main Street
Suite 300
Ann Arbor, MI 48104

Stacy L. Dimou
Duke Energy North America LLC
P.O. Box 426
Millinocket, ME 04462

George Johnson (Alt)
Attorney
Duke Energy North America LLC
c/o Dickstein, Shapiro, Morin & Oshinsky LLP
2101 L Street, N.W.
Washington, DC 20037-1526

David A. Samuels
Vice President
Dynegy Power Marketing, Inc.
c/o Dynegy Marketing and Trade
101 Merrimac Street, 2nd Floor
Boston, MA 02114

Miles Allen (Alt)
Sr. Vice President
Dynegy Power Marketing, Inc.
101 Merrimic Street, 2nd Floor
Boston, MA 02114

William Roberts
SVP Power Contracting
Edison Mission Marketing & Trading, Inc.
160 Federal Street
Boston, MA 02110-1776

Jeffry Ellis (Alt)
Edison Mission Marketing & Trading, Inc.
160 Federal Street
Boston, MA 02110-1776

Alan Foster
El Paso Merchant Energy, LP
70 Walnut Street
Wellesley Hills, MA 02481

Robert de R. Stein (Alt)
Principal Consultant
El Paso Merchant Energy, LP
c/o Signal Hill Consulting Group
128 Merchants Row
Suite 703
Rutland, VT 05701

Calvin P. Deschene
Director
Energy Atlantic, LLC
830 Main Street
Suite 20
P.O. Box 1148
Presque Isle, ME 04769-1148

Don Theriault (Alt)
Forecast Analyst
Energy Atlantic, LLC
P.O. Box 1148
Presque Isle, ME 04769-1148

Dennis J. Duffy
Energy Management, Inc.
One Energy Road
North Dartmouth, MA 02747

Chris Sherman (Alt)
Energy Management, Inc.
One Energy Road
North Dartmouth, MA 02747

Alan Cherkas
Executive Director, Structured Power, NE
Engage Energy America LLC
39500 High Pointe Blvd.
Suite 260
Novi, MI 48375

Terrence O'Reilly (Alt)
Vice President & Senior Counsel
Engage Energy America LLC
39500 High Pointe Blvd.
Suite 260
Novi, MI 48375

Edward Baughman
ENRON Power Marketing, Inc.
1400 Smith Street, ECS 04587
Houston, TX 77002-7361

Harlan E. Murphy (Alt.)
ENRON Power Marketing, Inc.
1400 Smith Street, EB 3811
Houston, TX 77002

Brent Dorsey
Entergy Nuclear Generation Company
P.O. Box 3200
Jackson, MS 39286

William Stone (Alt)
Entergy Nuclear Generation Company
600 Rocky Hill Road
Plymouth, MA 03260

Donald J. Sipe
Forster, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Forster, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Roberto R. Denis
Vice President
FPL Energy LLC
9250 W. Flagler Street
Suite 5494
Miami, FL 33174

Fernando DaSilva (Alt)
Director, Market Affairs
FPL Energy LLC
8 Woodlawn Road
Assonet, MA 02702

Donald J. Sipe
Gardiner Paperboard
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Gardiner Paperboard
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

William P. Short III
Generation Group Member
c/o Ridgewood Power Management, LLC
947 Linwood Avenue
Ridgewood, NJ 07450

Ralph DeGeeter (Alt)
Managing Director
Generation Group Member
c/o Quinnipiac Energy LLC
800 Village Walk #324
Guilford, CT 06437-2740

Wayne Snow
Manager
Georgetown Municipal Light Department
94 Searle Street
Georgetown, MA 01833

Roger W. Bacon (Alt)
Georgetown Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

NEPOOL Participants Committee
Members and Alternates

April 19, 2002

Roger H. Beeltje
Manager
Groton Electric Light Department
23 Station Avenue
Groton, MA 01450-4222

Roger W. Bacon (Alt)
Groton Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Christian Desilets
H.Q. Energy Services (U.S.) Inc.
75, boul. Rene-Levesque Ouest
17e etage
Montreal, Quebec H2Z 1A4
CANADA

John J. Bartus
H.Q. Energy Services (U.S.) Inc.
c/o Cameron McKenna
2175 K. St., NW
Washington, DC 20037

Joseph R. Spadea Jr.
Manager
Hingham Municipal Lighting Plant
222 Central Street
Hingham, MA 02043-2518

Roger W. Bacon (Alt)
Hingham Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Edla A. Bloom
Director
Holden Municipal Light Department
94 Reservoir Street
Holden, MA 01520

Roger W. Bacon (Alt)
Holden Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

James M. Lavelle
Manager
Holyoke Gas & Electric Department
99 Suffolk Street
Holyoke, MA 01040

Brian C. Beauregard (Alt)
Superintendent
Holyoke Gas & Electric Department
99 Suffold Street
Holyoke, MA 01040

Anthony J. Monteiro
General Manager
Hudson Light & Power Department
49 Forest Avenue
Hudson, MA 01749

Roger W. Bacon (Alt)
Hudson Light & Power Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

John A. MacLeod
Manager
Hull Municipal Lighting Plant
15 Edgewater Road
Hull, MA 02045-2714

Roger W. Bacon (Alt)
Hull Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Maurice T. Klefeker
Asset Manager
Indeck Pepperell Power Associates, Inc.
1075 Noel Avenue
Wheeling, IL 60090

Mark V. Magyar (Alt)
Consultant
Indeck Pepperell Power Associates, Inc.
c/o Financial Management Co.
325A Southbridge Street
Auburn, MA 01501

Donald J. Sipe
Industrial Energy Consumer Group
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Industrial Energy Consumer Group
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Raymond R. Shockey
Manager
Ipswich Municipal Light Department
P.O. Box 151
272 High Street
Ipswich, MA 01938-0151

Roger W. Bacon (Alt)
Ipswich Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Gordon van Welie
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Kevin Kirby (Alt)
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Richard Ruzika
Managing Director
J. Aron & Company
85 Broad Street
New York, NY 10004

Scott Weinstein (Alt)
Managing Director
J. Aron & Company
85 Broad Street
New York, NY 10004

Robert J. Gray
President
J.F. Gray & Associates LLC
35 Woodman Road
South Hampton, NH 03827

John F. Gray (Alt)
J.F. Gray & Associates LLC
35 Woodman Road
South Hampton, NH 03827

Jim Parmelee
Director of Power Markets
LIPA
31 Brinker Drive South
Rensselaer, NY 12144

John Higgins (Alt)
LIPA
c/o Navigant Consulting Inc.
200 Wheeler Road, Suite 4
Burlington, MA 01803

Scott Edwards
Assistant General Manager
Littleton Electric Light & Water Department
39 Ayer Road
P.O. Box 2406
Littleton, MA 01460-3406

Roger W. Bacon (Alt)
Littleton Electric Light & Water Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Paul Jutras
Maclaren Energy Inc.
2 Montreal Road West
Masson-Angers, Quebec, CANADA J8M 1K6

Richard St. Jean (Alt)
Maclaren Energy Inc.
2 Montreal Road West
Masson-Angers, Quebec, CANADA J8M 1K6

Robert O. Lenna (Alt)
Executive Director
Maine Health & Higher Educational Facilities Authority
3 University Drive
P.O. Box 2268
Augusta, ME 04338-2268

Stephen M. Gauthier
Program Manager
Maine Health & Higher Educational Facilities Authority
3 University Drive
P.O. Box 2268
Augusta, ME 04338-2268

Donald J. Sipe
Maine Skiing, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Maine Skiing, Inc.
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

John J. Beliveau
Director
Mansfield Electric Light Department
125 High Street, Suite 4
Mansfield, MA 02048-2404

Roger W. Bacon (Alt)
Mansfield Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Robert V. Jolly Jr.
Manager
Marblehead Municipal Light Department
80 Commercial Street
P.O. Box 369
Marblehead, MA 01945-0369

Roger W. Bacon (Alt)
Marblehead Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Neil Chayet
Massachusetts Energy Buyers Coalition
ML Strategies/MEBC
c/o Jennifer White
One Financial Center
Boston, MA 02111

Douglas Stevenson (Alt)
Massachusetts Energy Buyers Coalition
ML Strategies/MEBC
One Financial Center
Boston, MA 02111

Roger W. Bacon
Director, Power Services Division
Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Timothy Peet (Alt)
Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Derek Haskew
Massachusetts Public Interest Research Group
29 Temple Place
5th Floor
Boston, MA 02111

Robert Sargent (Alt)
Massachusetts Public Interest Research Group
29 Temple Place
5th Floor
Boston, MA 02111

Donald J. Sipe
Mead Oxford Corporation
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

Benjamin Bilus (Alt)
Mead Oxford Corporation
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle
P.O. Box 1058
Augusta, ME 04332-1058

James L. Collins
Energy Analyst
Middleborough Gas & Electric
2 Vine Street
Middleborough, MA 02346

Mayhew D. Seavey (Alt)
Principal
Middleborough Gas & Electric
c/o PLM, Inc.
35 Main Street
Hopkinton, MA 01748

Mark T. Kelly
Manager
Middleton Municipal Light Department
197 North Main Street
Middleton, MA 01949-1068

Roger W. Bacon (Alt)
Middleton Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Peter D. Fuller
Mirant New England, LLC
1099 Hingham Street
Rockland, MA 02370

Michael R. Kirkwood (Alt)
Mirant New England, LLC
1099 Hingham Street
Rockland, MA 02370

Catherine Flax
Senior Trader
Morgan Stanley Capital Group Inc.
1585 Broadway
4th floor
New York, NY 10036

Karen Kochonies (Alt)
Vice President, Gas & Electric Operations
Morgan Stanley Capital Group Inc.
1585 Broadway
4th Floor
New York, NY 10036

Peter G. Flynn
President
New England Power Company
25 Research Drive
Westborough, MA 01582

Masheed H. Rosenqvist (Alt)
Vice President
New England Power Company
25 Research Drive
Westborough, MA 01582

NEPOOL Participants Committee
Members and Alternates

April 19, 2002

Fred C. Anderson
General Manager
New Hampshire Electric Cooperative, Inc.
579 Tenney Mountain Highway
Plymouth, NH 03264-3147

Stephen Kaminski (Alt)
Director, Energy Access & Services
New Hampshire Electric Cooperative, Inc.
579 Tenney Mountain Highway
Plymouth, NH 03264-3147

Michael W. Holmes
Consumer Advocate
New Hampshire Office of Consumer Advocate
117 Manchester Street
Concord, NH 03301

Paul Peterson (Alt)
New Hampshire Office of Consumer Advocate
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Mark V. Magyar
North Attleborough Electric
c/o Financial Management Group
325A Southbridge Street
Auburn, MA 01501

Roger W. Bacon (Alt)
North Attleborough Electric
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Frank P. Sabatino
Senior Vice President - Power Marketing
Northeast Utilities System Companies
c/o Select Energy, Inc.
107 Selden Street
Berlin, CT 06037

James R. Shuckerow (Alt)
Director-Wholesale Power Contracts
Northeast Utilities System Companies
P.O. Box 270
Hartford, CT 06141-0270

Malcolm N. McDonald
Superintendent
Norwood Municipal Light Department
206 Central Street
Norwood, MA 02062-3567

Joseph DeVito
Regulatory Specialist
NRG Power Marketing Inc.
c/o NRG Energy
10 Southpond Circle
Cheshire, CT 06410

Joel Gordon (Alt)
NRG Power Marketing Inc.
7 Steeple Lane
Amherst, NH 03031

Theodore G. Garill
General Manager
Pascoag Fire District Electric Department
55 South Main Street
P.O. Box 107
Pascoag, RI 02859-0107

Roger W. Bacon (Alt)
Pascoag Fire District Electric Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Diane Dillman
Manager
Paxton Municipal Light Department
578 Pleasant Street
Paxton, MA 01612-1365

Roger W. Bacon (Alt)
Paxton Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Ronald Tabroff
Supervisor, Electrical Engineer
Peabody Municipal Light Plant
201 Warren Street, Ext.
Peabody, MA 01960-4208

Roger W. Bacon (Alt)
Peabody Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Steven C. Gilbert
PECO Energy Company
c/o Exelon Power Team
300 Exelon Way
Kennett Square, PA 19348

John O'Brien (Alt)
PECO Energy Company
c/o Sithe New England
The Schrafft Center
529 Main Street
Suite 605
Charlestown, MA 02129

Sarah Barpoulis
Senior Vice President
PG&E Energy Trading - Power, LP
7500 Old Georgetown Rd.
Bethesda, MD 20816

Philip C. Smith (Alt)
Director-Operations N.E.
PG&E Energy Trading - Power, LP
c/o PG&E National Energy Group
One Bowdoin Square
Boston, MA 02114-2910

Robert Ciolek
President
PowerOptions, Inc.
99 Summer Street
Boston, MA 02110-1240

Douglas Stevenson (Alt)
PowerOptions, Inc.
Rte. 1, P.O. Box 398
Wayne, ME 04284

John F. Brodbeck
Energy Consultant
PPL EnergyPlus, LLC
2 North Ninth Street
Allentown, PA 18101-1179

Garrith W. Kirkner (Alt)
PPL EnergyPlus, LLC
2 North Ninth Street
Allentown, PA 18101-1179

Robert A. Weishaar, Jr.
Counsel
Praxair, Inc.
1200 G. Street, N.W.
Suite 800
Washington, DC 20005

Jennifer Hunsperger (Alt)
Account Manager, Eastern Region
Praxair, Inc.
126 Windham Drive
Langhorne, PA 10947

Debra M. Bateman
Providence Energy Services, Inc.
Mail Stop GENWT21
East Office
56 Exchange Terrace
Providence, RI 02903

James M. Stephens (Alt)
Providence Energy Services, Inc.
56 Exchange Terrace
Providence, RI 02903

Howard A. Fromer
Director – Market Policy
Public Service Electric and Gas Company
c/o PSEG Power New York Inc.
130 Washington Avenue
Albany, NY 12210

Matthew D. Cox (Alt)
Regional Marketing Manager
Public Service Electric and Gas Company
80 Park Plaza - T21
Newark, NJ 07102-4194

Leonard D. Rucker
General Manager
Reading Municipal Light Department
230 Ash Street
P.O. Box 150
Reading, MA 01867-0250

Vincent F. Cameron Jr. (Alt)
Assistant General Manager - Energy and Operations
Reading Municipal Light Department
230 Ash Street
Reading, MA 01867-0250

Scott Cline
Director, Asset Management and Regulatory Affairs
Reliant Energy Services, Inc.
1111 Louisiana, 9th floor
Houston, TX 77002

Guinette Haas (Alt)
Eastern Region, Asset Management
Reliant Energy Services, Inc.
1111 Louisiana, 9th floor
Houston, TX 77002

G. Robert Merry
Manager
Rowley Municipal Light Plant
47 Summer Street
Rowley, MA 01969

Roger W. Bacon (Alt)
Rowley Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Schaefer, Marc
c/o SESCO, Inc.
2 Elmwood Drive
Rutland, VT 05701

Thomas Halleran
Sempra Energy Trading Group
58 Commerce Road
Stamford, CT 06902

Mark Magyar (Alt)
Sempra Energy Trading Group
c/o Financial Management Group
325A Southbridge Street
Auburn, MA 01501

Thomas R. Josie
General Manager
Shrewsbury Electric Light Plant
100 Maple Avenue
Shrewsbury, MA 01545-5398

Roger W. Bacon (Alt)
Shrewsbury Electric Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Silkman, Richard
76 Main Street
Yarmouth, ME 04096

Mary J. Healey
State of Connecticut, Office of Consumer Counsel
Ten Franklin Square
New Britain, CT 06051

Eugene M. Koss (Alt)
State of Connecticut, Office of Consumer Counsel
Ten Franklin Square
New Britain, CT 06051

Julie Hasham
Policy Development Specialist
State of Maine, Office of the Governor
38 State House Station
Augusta, ME 04333-0038

Stephen G. Ward (Alt)
Public Advocate
State of Maine, Office of the Governor
112 State House Station
Augusta, ME 04333

Kenneth S. Stambler
Assistant Vice President, Energy Supply
SmartEnergy.com, Inc.
200 Unicorn Park
Woburn, MA 01801

Tony Lopez-Lopez (Alt)
Chief Energy Operations Officer
SmartEnergy.com, Inc.
200 Unicorn Park
Woburn, MA 01801

Wayne D. Doerpholz
Manager
South Hadley Electric Light Department
85 Main Street
South Hadley, MA 01075-2706

Roger W. Bacon (Alt)
South Hadley Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

John Kilgo Jr.
Manager
Sterling Municipal Light Department
50 Main Street
Sterling, MA 01564-2129

Roger W. Bacon (Alt)
Sterling Municipal Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Michael Swider
Strategic Energy Ltd.
33 Sleeper St., Apt. #303
Boston, MA 02210

Jeffrey W. Knox (Alt)
Strategic Energy Ltd.
Two Gateway Center
9th Floor
Pittsburgh, PA 15222

R. Scott Whittemore
Manager Energy Services and Planning
Taunton Municipal Lighting Plant
55 Weir Street
P.O. Box 870
Taunton, MA 02780-0870

Brian Forshaw
Taunton Municipal Lighting Plant
c/o Connecticut Municipal Electric Energy Cooperative
30 Stott Avenue
Norwich, CT 06360-1535

Roger L. Buck
Executive Director
TEC-RI
7 Madeline Drive
Newport, RI 02840-1714

Michael Hoffer (Alt)
Vice Chairman Exec. Board
TEC-RI
7 Madeline Drive
Newport, RI 02840-1714

Gerald P. Skelton
Manager
Templeton Municipal Light Plant
School Street
Baldwinville, MA 01436

Roger W. Bacon (Alt)
Templeton Municipal Light Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Jeffrey Bergman
Utilities Manager
Texas Instruments
MS 10-04
34 Forest Street
Attleboro, MA 02703

Mark Sestak (Alt)
Facilities Engineer
Texas Instruments
MS 10-04
34 Forest Street
Attleboro, MA 02703

Max Remington
The Energy Consortium
132 Buckley Highway
Stafford, CT 06076

Roger Borghesani (Alt)
Chairman
The Energy Consortium
24 Hastings Road
Lexington, MA 02421-6807

Mark T. Ladrow
Marketing Manager
Tractebel Energy Marketing, Inc.
15 New England Executive Park
Suite 205
Burlington, MA 01803

Chris Bergamini
Power Trader
TransAlta Energy Marketing (U.S.) Inc.
151 West Street
Suite 300
Annapolis, MD 21401

Dan LoBue
Power Trader
TransAlta Energy Marketing (U.S.) Inc.
151 West Street
Suite 300
Annapolis, MD 21401

William C. Taylor
Vice President
TransCanada Power Marketing Ltd.
110 Turnpike Road
Suite 203
Westborough, MA 01581

Michael E. Hachey (Alt)
Director, Power Marketing
TransCanada Power Marketing Ltd.
110 Turnpike Road
Suite 203
Westborough, MA 01581

Michael S. Grim
Director, Markets & Regulatory
TXU Energy Trading Company LP
1717 Main Street, Suite 17000
Dallas, TX 75201

John Beeckman (Alt)
TXU Energy Trading Company LP
1717 Main Street
Suite 2000
Dallas, TX 75201

Kevin M. Foley
General Manager
UAE Lowell Power LLC
2 Tanner Street
Lowell, MA 01852

Teri M. Pagano (Alt)
UAE Lowell Power LLC
c/o United American Energy Corp.
50 Tice Boulevard
Woodcliff Lake, NJ 07677

Deborah Donovan
Union of Concerned Scientists
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Paul R. Peterson
Union of Concerned Scientists
c/o Synapse Energy Economics, Inc.
22 Pearl Street
Cambridge, MA 02139

Robert T. Gagliardi
Director, Strategic Policy
The United Illuminating Company
157 Church Street - 1-15D
P.O. Box 1564
New Haven, CT 06506-0901

Dennis Hrabchak (Alt)
Vice President Regulatory Policy
The United Illuminating Company
157 Church Street-15th Floor
P.O. Box 1564
New Haven, CT 06506-0901

David K. Foote
Vice President
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842-1720

David B. Doskocil (Alt)
Team Leader
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842-1720

Thomas N. Wies
Vice President & General Counsel
Vermont Electric Power Company, Inc.
366 Pinnacle Ridge Road
Rutland, VT 05701

Gerald Spring (Alt)
Vermont Electric Power Company, Inc.
366 Pinnacle Ridge Road
Rutland, VT 05701

William J. Gallagher
General Manager
Vermont Public Power Supply Authority
P.O. Box 298
Waterbury Center, VT 05677

Brian Evans-Mongeon (Alt)
Manager of Power Supply & Marketing Service
Vermont Public Power Supply Authority
P.O. Box 298
Waterbury Center, VT 05677

Ron Armstrong
Virginia Electric and Power Company
5000 Dominion Blvd. 3N
Glen Allen, VA 23060

Robert LaRochelle (Alt)
Virginia Electric and Power Company
5000 Dominion Blvd. 3N
Glen Allen, VA 23060

William J. Wallace
Manager
Wakefield Municipal Gas and Light Department
9 Albion Street
P.O. Box 190
Wakefield, MA 01880-0390

Roger W. Bacon (Alt)
Wakefield Municipal Gas and Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

John Scirpoli
Manager
West Boylston Municipal Lighting Plant
4 Crescent Street
West Boylston, MA 01583-1310

Roger W. Bacon (Alt)
West Boylston Municipal Lighting Plant
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Daniel Golubek (Alt)
Manager
Westfield Gas and Electric Light Department
100 Elm Street
Westfield, MA 01085-2907

Roger W. Bacon (Alt)
Westfield Gas and Electric Light Department
c/o Mass. Municipal Wholesale Electric Co.
Moody Street
P.O. Box 426
Ludlow, MA 01056-0246

Dennis Keener
Williams Energy Marketing & Trading Company
One Williams Center
Mail Drop 35-7
P.O. Box 3448
Tulsa, OK 74101-9567

Donald J. Sipe
Counsel
Wiscasset, Town of
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle, P.O. Box 1058
Augusta, ME 04432-1058

Benjamin Bilus (Alt)
Wiscasset, Town of
c/o Preti, Flaherty, Beliveau, Pachios & Haley
45 Memorial Circle, P.O. Box 1058
Augusta, ME 04432-1058

Daniel Checki
Director of Marketing
Wisvest-Connecticut, LLC
12 Progress Drive
Shelton, CT 06484

Michael Bekker (Alt)
Wisvest-Connecticut, LLC
12 Progress Drive
Shelton, CT 06484

Tim Charette
Power Marketing Executive
WPS Energy Services Inc.
1242 Lower Lyndon Street
Caribou, ME 04736

Ed Howard (Alt)
Power Marketing Executive
WPS Energy Services Inc.
1242 Lower Lyndon Street
Caribou, ME 04736

Wendy N. Reed
Wright & Talisman, P.C.
1200 G Street, N.W.
Suite 600
Washington, DC 20005

James H. McGrew, Esq.
Bruder, Gentile & Marcoux, LLP
1100 New York Avenue, N.W.
Suite 510, East
Washington, DC 20005-3934

Catherine J. Keuthen, Esq.
Boston Edison Company P361
800 Boylston Street
Boston, MA 02199-8003

John P. Coyle
Duncan & Allen
1575 Eye Street, N.W.
Washington, DC 20005

Robert L. Anderson
Frank Radigan
LBA Energy Services
270 River St., Suite 302
Troy, NY 12180

George H. Williams, Jr.
Cameron McKenna LLP
2175 K Street, NW, 5th Floor
Washington, DC 20037

Mary E. Grover, Esq.
COM/Energy Services Company
One Main Street
P.O. Box 9150
Cambridge, M A 02142-9150

Michael R. Kirkwood
Director of Supply Administration
Transmission Services and System Control
Commonwealth Electric Company
2421 Cranberry Highway
Wareham, MA 02571

Steven S. Garwood
Marc Guerrette
Central Maine Power Company
83 Edison Drive
Augusta, ME 04336

Bruce W. Bentley
Director, Integrated Resource Planning
Central Vermont Public Service Corporation
77 Grove Street
Rutland, Vermont 05701

Albert R. Simonds, Esq.
Bruder, Gentile & Marcoux, L.L.P.
1100 New York Avenue, N.W.
Suite 510 East
Washington, D.C. 20005-3934

John Michael Adragna, Esq.
Miller, Balis & O'Neil, P.C.
Suite 700
1140 Nineteenth Street, N.W.
Washington, DC 20036

Howard H. Shafferman
Ballard Spahr Andrews & Ingersoll
601 13th Street, N.W.
Suite 1000 South
Washington, DC 20005

Nicholas J. Scobbo, Jr., Esq.
Ferriter, Scobbo, Caruso & Rodophele, PC
75 State Street, 7th Floor
Boston, MA 02109

Alan J. Roth
Scott H. Strauss
Spiegel & McDiarmid
1350 New York Avenue, N.W.
Washington, DC 20005

Bruce McKinnon
Massachusetts Municipal Wholesale Electric Company
Stony Brook Energy Center
Moody Street
P.O. Box 426
Ludlow, MA 01056

Isaac D. Benkin
Winthrop, Stimson, Putnam & Roberts
1133 Connecticut Avenue, N.W.
Washington, DC 20036

Masheed H. Rosenqvist
Vice President of NEP and Director of
Transmission Marketing
New England Power Company
25 Research Drive
Westborough, MA 01582-0099

Michael E. Hachey
Vice President of NEP and Director of
Generation Marketing
New England Power Company
25 Research Drive
Westborough, MA 01582-0099

Monique Rowtham-Kennedy, Esq.
Northeast Utilities Service Company
107 Selden Street
Berlin, CT 06037

David B. Raskin, Esq.
Steptoe & Johnson LLP
1330 Connecticut Avenue, N.W.
Washington, DC 20036

Robert E. Fernandez, Esq.
c/o Sithe Energies, Inc.
450 Lexington Avenue
37th Floor
New York, NY 10017

David W. Schwartz
Jared W. Johnson
Latham & Watkins
1001 Pennsylvania Avenue, N.W.
Suite 1300
Washington, D.C. 20004

G. Philip Nowak, Esq.
Lorrie M. Marcil, Esq.
Sidley & Austin
1722 Eye Street, N.W.
Washington, D.C. 20006

Andrea J. Chambers, Esq.
Yvonne M. Coviello
LeBoeuf, Lamb, Greene & MacRae, LLP
1875 Connecticut Ave., NW
Washington, DC 20009-5728

David K. Foote
6 Liberty Lane West
Hampton, NH 03842-1720

Daniel E. DuBois
U.S. Generating Company
111 Washington Avenue, Suite 703
Albany, NY 12210

Larry F. Eisenstat, Esq.
Gretchen Schott, Esq.
Dickstein Shapiro Morin & Oshinsky, LLP
2101 L Street, N.W.
Washington, DC 20037

Tamara J. White
U.S. Generating Company
7500 Old Georgetown Road
Bethesda, MD 20814

Joseph H. Long, Esq.
Staff Attorney
Federal Energy Regulatory Commission/OCG
888 First Street, N.E.
Washington, DC 20426

New England Governors and Utility Regulatory and Related Agencies

April 19, 2002

Connecticut

The Honorable John G. Rowland
State Capitol
210 Capitol Ave.
Hartford, CT 06106

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine

The Honorable Angus S. King, Jr.
One State House Station
Rm. 236
Augusta, ME 04333-0001

Maine Public Utilities Commission
State House, Station 18
242 State Street
Augusta, ME 04333-0018

Massachusetts

The Honorable Jane Swift
Office of the Governor
Rm. 360 State House
Boston, MA 02133

Massachusetts Department of Telecommunications and Energy
One South Station
Boston, MA 02110

New Hampshire

The Honorable Jeanne Shaheen
State House Rm. 208
Concord, NH 03301

New Hampshire Public Utilities Commission
8 Old Suncook Road - Building #1
Concord, NH 03301

Rhode Island

The Honorable Lincoln Almond
State House Rm. 143
Providence, RI 02903

Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Vermont

The Honorable Howard Dean
109 State Street
Montpelier, VT 05609

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

New England Governors
and Utility Regulatory
and Related Agencies **April 19, 2002**

Michael H. Dworkin, President
New England Conference of
Public Utilities Commissioners, Inc.
c/o Chairman Dworkin, Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

Amy Ignatius, Esq.
Executive Director
New England Conference of
Public Utilities Commissioners, Inc.
One Eagle Square
Suite 514
Concord, NH 03301

Harvey L. Reiter, Esq.
Counsel for New England Conference
of Public Utilities Commissioners, Inc.
c/o MORRISON HECKER
1150 18th Street, N.W., Suite 800
Washington, DC 20036-3816

Power Planning Committee
New England Governors' Conference, Inc.
76 Summer Street, 2nd Floor
Boston, MA 02110

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Pool) Docket No. OA97-237-_______

NOTICE OF FILING
(April , 2002)

Take notice that on April 24, 2002, the New England Power Pool ("NEPOOL") Participants Committee and ISO New England Inc. ("ISO-NE") have jointly filed for acceptance materials reflecting compliance with the requirement of a certain settlement agreement approved by the Commission by order dated July 30, 1999, *New England Power Pool*, 88 FERC ¶61,140, that an audit of the charges for regional network service ("RNS") under the formula rate provisions of the NEPOOL Tariff for charges in effect for the NEPOOL rate years June 1, 1997 through May 31, 2000 be performed by or under the direction of ISO-NE, and that the results of that audit be submitted to the Commission as an informational filing.

The Participants Committee states that copies of these materials were sent to the New England state governors and regulatory commissions, the NEPOOL Participants and to the parties who executed the settlement agreement.

Any person desiring to intervene or to protest this filing should file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. All such motions or protests should be filed on or before the comment date, and, to the extent applicable, must be served on the applicant and on any other person designated on the official service list. This filing is available for review at the Commission or may be viewed on the Commission's web site at http://www.ferc.gov using the "RIMS" link, select "Docket #" and follow the instructions (call 202-208-2222 for assistance). Protests and interventions may be filed electronically via the Internet in lieu of paper; see 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site under the "e-Filing" link.

Comment Date: May , 2002

Magalie Roman Salas
Secretary

Record Request 3

Request:

Please describe what processes are in place to ensure that transmission construction costs are reasonable and necessary.

Response:

Please see Transmission Group Procedure-11 ("TGP-11"), which is the procedure that establishes the formal review and approval process for Transmission US strategies and capital/revenue investment proposals (programs, projects, interconnections, expenditures, and commitments). The Company is filing this procedure under a request for confidential treatment. In addition, please see the Company's response to Division Data Request 3-2 for a high-level description of the overall planning process followed by National Grid.

Prepared by or under the supervision of: P. A. Viapiano

Record Request 3

[**REDACTED ATTACHMENT**]

Record Request 4

Request:

(a) Please provide an updated forecast for Attachment JAL 2-14.

(b) Please indicate how current economic forecast is factored in.

Response:

(a) Attached is an updated forecast for Attachment JAL 2-14

(b) The load forecasts were obtained from monthly econometric models relating kWh sales and peak MW demand to state economic/demographic variables, weather variables and other explanatory variables affecting the demand for electricity. Historical kWh sales and peak demands were taken from company records. Historical and forecast economic and demographic explanatory variables were obtained under subscription service from Moody's Economy.com, a leading economic consulting firm which produces national, state and local economic forecasts. Historical weather explanatory variables were collected from the National Weather Service's Providence, RI weather station. Forecasted weather variables were set equal to normal, defined as a 30-year historical average. Other explanatory variables used in the models include electricity price, number of days billed per month and monthly hours of daylight. These variables were calculated from company records, meter reading schedules and monthly sunrise/sunset times.

The forecasts were prepared in September 2008 using Moody's latest economic projections. At that time, Moody's predicted that the state of Rhode Island was in a regional recession that would bottom out in the second quarter and that growth would resume in the second half of 2009. The kWh forecast has not yet been updated using Moody's latest economic projections for Rhode Island. However, actual kWh data are included through November 2008.

Prepared by or under the supervision of: Jeanne A. Lloyd

Rhode Island KWh

Year	Narragansett Electric Company	EUA Blackstone Valley Electric	EUA Newport Electric Company	Rhode Island*	Growth Rate
1996	4,794,526,283	1,261,928,473	527,616,285	6,584,071,041	
1997	4,837,062,158	1,279,049,317	536,087,074	6,652,198,549	1.0%
1998	4,985,569,115	1,300,878,833	543,599,695	6,830,047,643	2.7%
1999	5,172,952,619	1,332,975,730	567,395,617	7,073,323,966	3.6%
2000	6,836,839,127	227,232,256	101,954,207	7,166,025,590	1.3%
2001	7,341,196,303	0	0	7,341,196,303	2.4%
2002	7,515,614,036	0	0	7,515,614,036	2.4%
2003	7,694,091,639	0	0	7,694,091,639	2.4%
2004	7,822,279,925	0	0	7,822,279,925	1.7%
2005	7,985,335,205	0	0	7,985,335,205	2.1%
2006	7,732,329,004	0	0	7,732,329,004	-3.2%
2007	7,879,655,164	0	0	7,879,655,164	1.9%
2008**	7,803,897,000	0	0	7,803,897,000	-1.0%
2009	7,875,447,000	0	0	7,875,447,000	0.9%
2010	8,021,461,000	0	0	8,021,461,000	1.9%
2011	8,139,610,000	0	0	8,139,610,000	1.5%
2012	8,214,258,000	0	0	8,214,258,000	0.9%
2013	8,268,415,000	0	0	8,268,415,000	0.7%
2014	8,316,775,000	0	0	8,316,775,000	0.6%

Rhode Island Peak Load (MW)

Year	Mo	Narragansett Electric Company	EUA Blackstone Valley Electric	EUA Newport Electric Company	Rhode Island*	Growth Rate
1996	8	930.1	244.3	86.8	1,261.2	
1997	7	1,031.6	264.2	97.7	1,393.5	10.5%
1998	7	1,048.0	268.9	101.5	1,418.4	1.8%
1999	7	1,133.0	265.7	111.9	1,510.6	6.5%
2000	8	1,087.8	278.8	108.8	1,475.4	-2.3%
2001	8	1,663.3	304.7	120.6	1,663.3	12.7%
2002	8	1,687.1	310.5	117.5	1,687.1	1.4%
2003	6	1,556.0	267.0	111.0	1,556.0	-7.8%
2004	8	1,601.7	289.1	117.5	1,601.7	2.9%
2005	7	1,738.3	310.9	110.1	1,738.3	8.5%
2006	8	1,932.0	334.9	142.8	1,932.0	11.1%
2007	8	1,768.0	305.6	128.1	1,768.0	-8.5%
2008	6	1,780.2	306.4	130.3	1,780.2	0.7%
2009	8	1,833.7	307.4	132.6	1,833.7	3.0%
2010	8	1,867.1	308.3	134.8	1,867.1	1.8%
2011	8	1,898.9	309.0	137.0	1,898.9	1.7%
2012	8	1,930.8	309.7	139.1	1,930.8	1.7%
2013	8	1,962.7	310.4	141.3	1,962.7	1.6%
2014	8	1,994.4	311.0	143.4	1,994.4	1.6%

* Excludes Pascoag Fire District.
** 2008 kWh are 11 months actual and 1 month foreast. 2008 Rhode Island peaks are actual. 2008 Blackstone and Newport peak MW are estimated.

Record Request 5

Request:

Please describe how the Company would respond to a customer inquiry regarding the need for transmission rate increases.

Response:

National Grid would provide customers with the following explanatory information:

- Narragansett Electric incurs RNS expenses for Pool Transmission Facilities (PTF) based on rates set according to the FERC-approved ISO-NE Transmission, Markets and Services Tariff.

- The majority of transmission costs incurred from ISO-NE by Narragansett Electric are based on a single New England-wide RNS rate. All customer load in New England pays the same rate for the PTF supporting the New England backbone transmission system.

- There is a need for enhanced investment in the transmission system to ensure reliability and to prepare for the future as part of a broader picture in which electric utilities and regulators nationwide are confronting the need for increased infrastructure investment, given the age and condition of the existing transmission systems.

  The American Society of Civil Engineers ("ASCE"), which has been doing a periodic assessment of U.S. infrastructure since 1998, reported in its 2005 assessment update that "the state of the [electric] grid remains a cause for deep concern among the experts."

  The U.S. power transmission system is in urgent need of modernization. Growth in electricity demand and investment in new power plants has not been matched by investment in new transmission facilities. Maintenance expenditures have decreased 1% per year since 1992. Existing transmission facilities were not designed for the current level of demand. Infrastructure report card 2005, http://www.ASCE.orgreportcard/2005.

Record Request 5 (cont.)

Similarly, Electric Power Research Institute's ("EPRI") Clark Gellings and Kurt Yeager explain: "The power delivery system is largely based on technology developed in the 1950s or earlier and installed as much as 50 years ago. The strain on this aging system is beginning to show, particularly as consumers ask it to do things it was not designed to do….An additional and significant stress on the North American power delivery system results from the discrepancy between the growth in demand for power and the expansion of the delivery system to meet that demand. From 1988 to 1998, US electricity demand rose by nearly 30% while the transmission network's capacity grew by only 15%." [1]

- Bringing transmission infrastructure up to appropriate levels will require very large investments over multi-year periods. ISO-NE has identified in its most recent release of the Regional System Plan the need for over $7 billion of investment over the next five years.

Prepared by or under the supervision of: P. A. Viapiano

[1] Transforming the Electric Infrastructure, Clark W. Gellings and Kurt E. Yeager, Physics Today (December 2004), at P. 48.

Record Request 6

Request:

What are the estimated increases in profits National Grid will receive on the estimated National Grid plant investment as shown in the Regional System Plan for 2009 through 2013 as provided in response to Division Data Request 2-6?

Response:

Please see the attached analysis, which shows the estimated increase in profits associated with new PTF transmission investment at the current ROE of 11.64%. The impact of the incremental 125 basis point adder associated with the NEEWS project is broken out separately.

Prepared by or under the supervision of: P. A. Viapiano

New England Power Company / Narragansett Electric Company
Estimated Incremental Return on Equity
for Transmission Investment
For the Period January 1, 2009 - December 31, 2013
(Thousands of Dollars)

		2009	2010	2011	2012	2013	Total Investment
1	Total Estimated Plant In-service	$ 156,200	$ 247,900	$ 363,900	$ 260,400	$ 365,300	$ 1,393,700
2	Cummulative Plant In-Service	$ 156,200	$ 404,100	$ 768,000	$ 1,028,400	$ 1,393,700	
3	Estimated Cumulative PTF Return on Equity at 11.64%	$ 11,160	$ 28,399	$ 53,196	$ 69,550	$ 92,710	
4	Estimated Cumulative NEEWS Incentive Adder for NEP at 1.25%	$ 143	$ 277	$ 657	$ 932	$ 1,133	
5	Estimated Cumulative NEEWS Incentive Adder for NECO at 1.25%	$ 100	$ 424	$ 1,050	$ 2,477	$ 2,747	
6	Total Estimated Return on Equity	$ 11,404	$ 29,100	$ 54,903	$ 72,959	$ 96,590	

Source:
Line 1: Page 8
Line 3: Page 2
Line 4: Page 3
Line 5: Page 4

New England Power Company
Estimated Incremental Return on Equity at 11.64 to National Grid
for Transmission Investment
For the Period January 1, 2009 - December 31, 2013
(Thousands of Dollars)

(1) Line No	(2) Description		(3) Amount	(4) Reference
	2009			
8				
9	Plus 2009 Projected Capital Additions	$	156,200	Page 8
10	Gross Upgrades Plant @ 12/31/2009	$	156,200	Line 8 + 9
11	Accumulated Depreciation Expense		1,953	Pg. 8, Ln.3. Col. 4
12	Accumulated Deferred Income taxes		1,367	Pg. 8, Ln.13. Col. 4
13	Net Plant @ 12/31/2009	$	152,881	Line 10-11-12
14	2009 Incremental Return and Taxes (2008-2009 in-service plant)		11,160	Page 5, Line 16
	2010			
14	Gross Upgrades Plant @ 12/31/2009	$	156,200	Line 10
15	Plus 2010 Projected Capital Additions	$	247,900	Page 8
16	Gross Upgrades Plant @ 12/31/2010	$	404,100	Line 14 + 15
17	Accumulated Depreciation Expense		8,956	Pg. 8, Ln.3. Col. 5
18	Accumulated Deferred Income taxes		6,116	Pg. 8, Ln.13. Col. 5
19	Net Plant @ 12/31/2010	$	389,028	Line 16-17-18
20	2010 Incremental Return and Taxes (2008-2010 in-service plant)		28,399	Page 5, Line 16
	2011			
21	Gross Upgrades Plant @ 12/31/2010	$	404,100	Line 16
22	Plus 2011 Projected Capital Additions	$	363,900	Page 8
23	Gross Upgrades Plant @ 12/31/2011	$	768,000	Line 21+22
24	Accumulated Depreciation Expense		23,608	Pg. 8, Ln.3. Col. 6
25	Accumulated Deferred Income taxes		15,678	Pg. 8, Ln.13. Col. 6
26	Net Plant @ 12/31/2011	$	728,715	Line 23-24-25
27	2011 Incremental Return and Taxes (2008-2011 in-service plant)		53,196	Page 5, Line 16
	2012			
28	Gross Upgrades Plant @ 12/31/2011	$	768,000	Line 23
29	Plus 2012 Projected Capital Additions	$	260,400	Page 8
30	Gross Upgrades Plant @ 12/31/2012	$	1,028,400	Line 28+29
31	Accumulated Depreciation Expense		46,063	Pg. 8, Ln.3. Col. 7
32	Accumulated Deferred Income taxes		29,601	Pg. 8, Ln.13. Col. 7
33	Net Plant @ 12/31/2012	$	952,736	Line 30-31-32
34	2012 Incremental Return and Taxes (2008-2012 in-service plant)		69,550	Page 5, Line 16
	2013			
35	Gross Upgrades Plant @ 12/31/2012	$	1,028,400	Line 30
36	Plus 2013 Projected Capital Additions	$	365,300	Page 8
37	Gross Upgrades Plant @ 12/31/2013	$	1,393,700	Line 35+36
38	Accumulated Depreciation Expense		76,339	Pg. 8, Ln.3. Col. 8
39	Accumulated Deferred Income taxes		47,365	Pg. 8, Ln.13. Col. 8
40	Net Plant @ 12/31/2013	$	1,269,996	Line 37-38-39
41	2013 Incremental Return and Taxes (2008-2013 in-service plant)		92,710	Page 5, Line 16

For Illustrative Purposes Only

New England Power Company
Estimated Incremental Return and taxes for 125bp Incentive
on NEEWS Upgrades
For the Period January 1, 2009 - December 31, 2013
(Thousands of Dollars)

(1) Line No	(2) Description		(3) Amount	(4) Reference
	2008			
1	Gross Upgrades Plant @ 12/31/2007	$	-	
2	Plus 2008 Projected Capital Additions	$	10,841	Page 9
3	Gross Upgrades Plant @ 12/31/2008	$	10,841	Line 1 + 2
4	Accumulated Depreciation Expense		136	Pg. 9, Ln.3. Col. 4
5	Accumulated Deferred Income taxes		95	Pg. 9, Ln.13. Col. 4
6	Net Plant @ 12/31/2008	$	10,611	Line 3-4-5
7	2008 Incremental Return and Taxes (2008-2009 in-service plant)		-	Page 6, Line 16
	2009			
8	Gross Upgrades Plant @ 12/31/2009	$	10,841	Line 3
9	Plus 2009 Projected Capital Additions	$	8,369	Page 9
10	Gross Upgrades Plant @ 12/31/2009	$	19,210	Line 8 + 9
11	Accumulated Depreciation Expense		511	Pg. 9, Ln.3. Col. 4
12	Accumulated Deferred Income taxes		347	Pg. 9, Ln.13. Col. 4
13	Net Plant @ 12/31/2009	$	18,352	Line 10-11-12
14	2009 Incremental Return and Taxes (2008-2009 in-service plant)		143	Page 6, Line 16
	2010			
14	Gross Upgrades Plant @ 12/31/2009	$	19,210	Line 10
15	Plus 2010 Projected Capital Additions	$	18,343	Page 9
16	Gross Upgrades Plant @ 12/31/2010	$	37,553	Line 14 + 15
17	Accumulated Depreciation Expense		1,221	Pg. 9, Ln.3. Col. 5
18	Accumulated Deferred Income taxes		804	Pg. 9, Ln.13. Col. 5
19	Net Plant @ 12/31/2010	$	35,528	Line 16-17-18
20	2010 Incremental Return and Taxes (2008-2010 in-service plant)		277	Page 6, Line 16
	2011			
21	Gross Upgrades Plant @ 12/31/2010	$	37,553	Line 16
22	Plus 2011 Projected Capital Additions	$	51,286	Page 9
23	Gross Upgrades Plant @ 12/31/2011	$	88,839	Line 21+22
24	Accumulated Depreciation Expense		2,801	Pg. 9, Ln.3. Col. 6
25	Accumulated Deferred Income taxes		1,818	Pg. 9, Ln.13. Col. 6
26	Net Plant @ 12/31/2011	$	84,220	Line 23-24-25
27	2011 Incremental Return and Taxes (2008-2011 in-service plant)		657	Page 6, Line 16
	2012			
28	Gross Upgrades Plant @ 12/31/2011	$	88,839	Line 23
29	Plus 2012 Projected Capital Additions	$	39,645	Page 9
30	Gross Upgrades Plant @ 12/31/2012	$	128,484	Line 28+29
31	Accumulated Depreciation Expense		5,517	Pg. 9, Ln.3. Col. 7
32	Accumulated Deferred Income taxes		3,510	Pg. 9, Ln.13. Col. 7
33	Net Plant @ 12/31/2012	$	119,457	Line 30-31-32
34	2012 Incremental Return and Taxes (2008-2012 in-service plant)		932	Page 6, Line 16
	2013			
35	Gross Upgrades Plant @ 12/31/2012	$	128,484	Line 30
36	Plus 2013 Projected Capital Additions	$	31,518	Page 9
37	Gross Upgrades Plant @ 12/31/2013	$	160,002	Line 35+36
38	Accumulated Depreciation Expense		9,123	Pg. 9, Ln.3. Col. 8
39	Accumulated Deferred Income taxes		5,626	Pg. 9, Ln.13. Col. 8
40	Net Plant @ 12/31/2013	$	145,253	Line 37-38-39
41	2013 Incremental Return and Taxes (2008-2013 in-service plant)		1,133	Page 6, Line 16

The Narragansett Electric Company
Estimated Incremental Return and taxes for 125bp Incentive
on NEEWS Upgrades
For the Period January 1, 2009 - December 31, 2013
(Thousands of Dollars)

(1) Line No	(2) Description		(3) Amount	(4) Reference
	2008			
1	Gross Upgrades Plant @ 12/31/2007	$	-	
2	Plus 2008 Projected Capital Additions	$	9,647	Page 10
3	Gross Upgrades Plant @ 12/31/2008	$	9,647	Line 1 + 2
4	Accumulated Depreciation Expense		121	Pg. 10, Ln.3. Col. 4
5	Accumulated Deferred Income taxes		84	Pg. 10, Ln.13. Col. 4
6	Net Plant @ 12/31/2008	$	9,442	Line 3-4-5
7	2008 Incremental Return and Taxes (2008-2009 in-service plant)		-	Page 6, Line 16
	2009			
8	Gross Upgrades Plant @ 12/31/2009	$	9,647	Line 3
9	Plus 2009 Projected Capital Additions	$	7,048	Page 10
10	Gross Upgrades Plant @ 12/31/2009	$	16,695	Line 8 + 9
11	Accumulated Depreciation Expense		450	Pg. 10, Ln.3. Col. 4
12	Accumulated Deferred Income taxes		305	Pg. 10, Ln.13. Col. 4
13	Net Plant @ 12/31/2009	$	15,940	Line 10-11-12
14	2009 Incremental Return and Taxes (2008-2009 in-service plant)		100	Page 6, Line 16
	2010			
14	Gross Upgrades Plant @ 12/31/2009	$	16,695	Line 10
15	Plus 2010 Projected Capital Additions	$	53,094	Page 10
16	Gross Upgrades Plant @ 12/31/2010	$	69,789	Line 14 + 15
17	Accumulated Depreciation Expense		1,531	Pg. 10, Ln.3. Col. 5
18	Accumulated Deferred Income taxes		1,027	Pg. 10, Ln.13. Col. 5
19	Net Plant @ 12/31/2010	$	67,231	Line 16-17-18
20	2010 Incremental Return and Taxes (2008-2010 in-service plant)		424	Page 6, Line 16
	2011			
21	Gross Upgrades Plant @ 12/31/2010	$	69,789	Line 16
22	Plus 2011 Projected Capital Additions	$	104,469	Page 10
23	Gross Upgrades Plant @ 12/31/2011	$	174,258	Line 21+22
24	Accumulated Depreciation Expense		4,582	Pg. 10, Ln.3. Col. 6
25	Accumulated Deferred Income taxes		3,046	Pg. 10, Ln.13. Col. 6
26	Net Plant @ 12/31/2011	$	166,631	Line 23-24-25
27	2011 Incremental Return and Taxes (2008-2011 in-service plant)		1,050	Page 6, Line 16
	2012			
28	Gross Upgrades Plant @ 12/31/2011	$	174,258	Line 23
29	Plus 2012 Projected Capital Additions	$	238,678	Page 10
30	Gross Upgrades Plant @ 12/31/2012	$	412,936	Line 28+29
31	Accumulated Depreciation Expense		11,921	Pg. 10, Ln.3. Col. 7
32	Accumulated Deferred Income taxes		7,835	Pg. 10, Ln.13. Col. 7
33	Net Plant @ 12/31/2012	$	393,180	Line 30-31-32
34	2012 Incremental Return and Taxes (2008-2012 in-service plant)		2,477	Page 6, Line 16
	2013			
35	Gross Upgrades Plant @ 12/31/2012	$	412,936	Line 30
36	Plus 2013 Projected Capital Additions	$	60,724	Page 10
37	Gross Upgrades Plant @ 12/31/2013	$	473,660	Line 35+36
38	Accumulated Depreciation Expense		23,004	Pg. 10, Ln.3. Col. 8
39	Accumulated Deferred Income taxes		14,692	Pg. 10, Ln.13. Col. 8
40	Net Plant @ 12/31/2013	$	435,964	Line 37-38-39
41	2013 Incremental Return and Taxes (2008-2013 in-service plant)		2,747	Page 6, Line 16

New England Power Company

Incremental Return and Taxes

(A)

Line No.		CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
1	LONG-TERM DEBT	$410,350,000	37.22%			
2	PREFERRED STOCK	$1,111,700	0.10%			0.00%
3	COMMON EQUITY	$691,116,667	62.68%	11.64%	7.30%	7.30%
4	TOTAL INVESTMENT RETURN	$1,102,578,367	100.00%		7.30%	7.30%

	Incremental Return 2009	**Incremental Return 2010**	**Incremental Return 2011**	**Incremental Return 2012**	**Incremental Return 2013**
14 INVESTMENT BASE	$152,881	$389,028	$728,715	$952,736	$1,269,996
15 x Cost of Capital Rate	7.3%	7.3%	7.3%	7.3%	7.3%
16 = Investment Return and Income Taxes	$11,160	$28,399	$53,196	$69,550	$92,710

(A) 12/31/07 data as included in PTO's annual information filing of 7/31/08 Docket No. ER08-1328

New England Power Company

Incremental Return and Taxes

(A)

Line No.		CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
1	LONG-TERM DEBT	$410,350,000	37.22%			
2	PREFERRED STOCK	$1,111,700	0.10%			0.00%
3	COMMON EQUITY	$691,116,667	62.68%	1.25%	0.78%	0.78%
4	TOTAL INVESTMENT RETURN	$1,102,578,367	100.00%		0.78%	0.78%

	Incremental Return 2009	**Incremental Return 2010**	**Incremental Return 2011**	**Incremental Return 2012**	**Incremental Return 2013**
14 INVESTMENT BASE	$18,352	$35,528	$ 84,220	$119,457	$145,253
15 x Cost of Capital Rate	0.78%	0.78%	0.78%	0.78%	0.78%
16 = Investment Return and Income Taxe	$143	$277	$657	$932	$1,133

(A) 12/31/07 data as included in PTO's annual information filing of 7/31/08 Docket No. ER08-1328

Narragansett Electric Company

Incremental Return and Taxes

(A)

Line No.		CAPITALIZATION 12/31/2007	CAPITALIZATION RATIOS	COST OF CAPITAL	COST OF CAPITAL	EQUITY PORTION
1	LONG-TERM DEBT	$247,784,016	45.00%			
2	PREFERRED STOCK	$27,513,557	5.00%			0.00%
3	COMMON EQUITY	$275,315,574	50.00%	1.25%	0.63%	0.63%
4	TOTAL INVESTMENT RETURN	$550,613,147	100.00%		0.63%	0.63%

	Incremental Return 2009	**Incremental Return 2010**	**Incremental Return 2011**	**Incremental Return 2012**	**Incremental Return 2013**
14 INVESTMENT BASE	$15,940	$ 67,231	$166,631	$ 393,180	$435,964
15 x Cost of Capital Rate	0.63%	0.63%	0.63%	0.63%	0.63%
16 = Investment Return and Inc	$100	$424	$1,050	$2,477	$2,747

(A) 12/31/07 data as settled in IFA Docket ER07-694-000

New England Power Company
Accumulated Deferred Income Tax
Estimated Transmission Upgrades
(Thousands of Dollars)

(1) Line No	(2) Description	(3) 2008	(4) 2009	(5) 2010	(6) 2011	(7) 2012	(8) 2013
	Book Value						
	In-service adds						
	2008	$ -	$ -	$ -	$ -	$ -	$ -
	2009		$ 156,200	$ 156,200	$ 156,200	$ 156,200	$ 156,200
	2010			247,900	247,900	247,900	247,900
	2011				363,900	363,900	363,900
	2012					260,400	260,400
	2013						365,300
1	Total Book Value/Total In-service	$ -	$ 156,200	$ 404,100	$ 768,000	$ 1,028,400	$ 1,393,700
2	Annual Depreciation Expense (a)	-	1,953	7,004	14,651	22,455	30,276
3	Accumulated Depreciation (b)	-	1,953	8,956	23,608	46,063	76,339
4	Net Book Value (Line 1-3)	-	154,248	395,144	744,393	982,338	1,317,361
	Tax Basis						
	In-service adds						
	2008	$ -	$ -	$ -	$ -	$ -	$ -
	2009		$ 156,200	$ 156,200	$ 156,200	$ 156,200	$ 156,200
	2010			$ 247,900	$ 247,900	$ 247,900	$ 247,900
	2011				$ 363,900	$ 363,900	$ 363,900
	2012					$ 260,400	$ 260,400
	2013						$ 365,300
5	Total Tax Basis	$ -	$ 156,200	$ 404,100	$ 768,000	$ 1,028,400	$ 1,393,700
6	Annual Tax Depreciation Expense (line 17)	-	5,858	20,572	41,972	62,236	81,031
7	Accumulated Tax Depreciation (b)	-	5,858	26,430	68,401	130,637	211,668
8	Net Tax Basis (Line 5-7)	-	150,343	377,670	699,599	897,763	1,182,032
9	Net Book Value (Line 4)	$ -	$ 154,248	$ 395,144	$ 744,393	$ 982,338	$ 1,317,361
10	Net Tax Basis (Line 8)	$ -	$ 150,343	$ 377,670	$ 699,599	$ 897,763	$ 1,182,032
11	Difference (Line 9-10)	-	3,905	17,474	44,794	84,575	135,330
12	Effective Tax Rate (c)	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%
13	ADIT (Line 11*12)	$ -	$ 1,367	$ 6,116	$ 15,678	$ 29,601	$ 47,365
	State Tax Depreciation	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	2008						
	In-Service Adds	$ -	$ -	$ -	$ -	$ -	$ -
	MACRS Rate	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
14	Total Depreciation	$ -	$ -	$ -	$ -	$ -	$ -
	2009						
	In-Service Adds		$ 156,200	$ 156,200	$ 156,200	$ 156,200	$ 156,200
	MACRS Rate		3.750%	7.219%	6.677%	6.177%	5.713%
15	Total Depreciation		$ 5,858	$ 11,276	$ 10,429	$ 9,648	$ 8,924
	2010						
	In-Service Adds			247,900	247,900	247,900	247,900
	MACRS Rate			3.750%	7.219%	6.677%	6.177%
16	Total Depreciation			$ 9,296	$ 17,896	$ 16,552	$ 15,313
	2011						
	In-Service Adds				363,900	363,900	363,900
	MACRS Rate				3.750%	7.219%	6.677%
	Total Depreciation				$ 13,646	$ 26,270	$ 24,298
	2012						
	In-Service Adds					260,400	260,400
	MACRS Rate					3.750%	7.219%
	Total Depreciation					$ 9,765	$ 18,798
	2013						
	In-Service Adds						365,300
	MACRS Rate						3.750%
	Total Depreciation						$ 13,699
17	Total Yearly Depreciation	$ -	$ 5,858	20,572	$ 41,972	$ 62,236	$ 81,031

Notes:
(a) Previous year line 3 + Current year line 2.
(b) Previous year line 7 + Current year line 6.
(c) 2007 effective tax rate used as an estimate for all years
(d) Minor variances due to rounding

New England Power Company
Accumulated Deferred Income Tax
Estimated Transmission Upgrades
(Thousands of Dollars)

(1) Line No	(2) Description	(3) 2008	(4) 2009	(5) 2010	(6) 2011	(7) 2012	(8) 2013
	Book Value						
	In-service adds						
	2008	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841
	2009		$ 8,369	$ 8,369	$ 8,369	$ 8,369	$ 8,369
	2010			18,343	18,343	18,343	18,343
	2011				51,286	51,286	51,286
	2012					39,645	39,645
	2013						31,518
1	Total Book Value/Total In-service	$ 10,841	$ 19,210	$ 37,553	$ 88,839	$ 128,484	$ 160,002
2	Annual Depreciation Expense (a)	136	376	710	1,580	2,717	3,606
3	Accumulated Depreciation (b)	136	511	1,221	2,801	5,517	9,123
4	Net Book Value (Line 1-3)	10,705	18,699	36,332	86,038	122,967	150,879
	Tax Basis						
	In-service adds						
	2008	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841
	2009		$ 8,369	$ 8,369	$ 8,369	$ 8,369	$ 8,369
	2010			$ 18,343	$ 18,343	$ 18,343	$ 18,343
	2011				$ 51,286	$ 51,286	$ 51,286
	2012					$ 39,645	$ 39,645
	2013						$ 31,518
5	Total Tax Basis	$ 10,841	$ 19,210	$ 37,553	$ 88,839	$ 128,484	$ 160,002
6	Annual Tax Depreciation Expense (line 17)	407	1,096	2,016	4,476	7,550	9,652
7	Accumulated Tax Depreciation (b)	407	1,503	3,519	7,995	15,545	25,197
8	Net Tax Basis (Line 5-7)	10,434	17,707	34,034	80,844	112,939	134,805
9	Net Book Value (Line 4)	$ 10,705	$ 18,699	$ 36,332	$ 86,038	$ 122,967	$ 150,879
10	Net Tax Basis (Line 8)	$ 10,434	$ 17,707	$ 34,034	$ 80,844	$ 112,939	$ 134,805
11	Difference (Line 9-10)	271	992	2,298	5,194	10,028	16,074
12	Effective Tax Rate (c)	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%
13	ADIT (Line 11*12)	$ 95	$ 347	$ 804	$ 1,818	$ 3,510	$ 5,626

	State Tax Depreciation	2008	2009	2010	2011	2012	2013
	2008						
	In-Service Adds	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841	$ 10,841
	MACRS Rate	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
14	Total Depreciation	$ 407	$ 783	$ 724	$ 670	$ 619	$ 573
	2009						
	In-Service Adds		$ 8,369	$ 8,369	$ 8,369	$ 8,369	$ 8,369
	MACRS Rate		3.750%	7.219%	6.677%	6.177%	5.713%
15	Total Depreciation		$ 314	$ 604	$ 559	$ 517	$ 478
	2010						
	In-Service Adds			18,343	18,343	18,343	18,343
	MACRS Rate			3.750%	7.219%	6.677%	6.177%
16	Total Depreciation			$ 688	$ 1,324	$ 1,225	$ 1,133
	2011						
	In-Service Adds				51,286	51,286	51,286
	MACRS Rate				3.750%	7.219%	6.677%
	Total Depreciation				$ 1,923	$ 3,702	$ 3,424
	2012						
	In-Service Adds					39,645	39,645
	MACRS Rate					3.750%	7.219%
	Total Depreciation					$ 1,487	$ 2,862
	2013						
	In-Service Adds						31,518
	MACRS Rate						3.750%
	Total Depreciation						$ 1,182
17	Total Yearly Depreciation	$ 407	$ 1,096	2,016	$ 4,476	$ 7,550	$ 9,652

Notes:
(a) Previous year line 3 + Current year line 2.
(b) Previous year line 7 + Current year line 6.
(c) 2007 effective tax rate used as an estimate for all years
(d) Minor variances due to rounding

The Narragansett Electric Company
Accumulated Deferred Income Tax
Estimated NEEWS Project
(Thousands of Dollars)

(1) Line No	(2) Description	(3) 2008	(4) 2009	(5) 2010	(6) 2011	(7) 2012	(8) 2013
	Book Value						
	In-service adds						
	2008	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647
	2009		$ 7,048	$ 7,048	$ 7,048	$ 7,048	$ 7,048
	2010			53,094	53,094	53,094	53,094
	2011				104,469	104,469	104,469
	2012					238,678	238,678
	2013						60,724
1	Total Book Value/Total In-service	$ 9,647	$ 16,695	$ 69,789	$ 174,258	$ 412,936	$ 473,660
2	Annual Depreciation Expense (a)	121	329	1,081	3,051	7,340	11,082
3	Accumulated Depreciation (b)	121	450	1,531	4,582	11,921	23,004
4	Net Book Value (Line 1-3)	9,526	16,245	68,258	169,677	401,015	450,656
	Tax Basis						
	In-service adds						
	2008	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647
	2009		$ 7,048	$ 7,048	$ 7,048	$ 7,048	$ 7,048
	2010			$ 53,094	$ 53,094	$ 53,094	$ 53,094
	2011				$ 104,469	$ 104,469	$ 104,469
	2012					$ 238,678	$ 238,678
	2013						$ 60,724
5	Total Tax Basis	$ 9,647	$ 16,695	$ 69,789	$ 174,258	$ 412,936	$ 473,660
6	Annual Tax Depreciation Expense (line 17)	362	961	3,144	8,817	21,024	30,675
7	Accumulated Tax Depreciation (b)	362	1,322	4,466	13,283	34,307	64,982
8	Net Tax Basis (Line 5-7)	9,285	15,373	65,323	160,975	378,629	408,678
9	Net Book Value (Line 4)	$ 9,526	$ 16,245	$ 68,258	$ 169,677	$ 401,015	$ 450,656
10	Net Tax Basis (Line 8)	$ 9,285	$ 15,373	$ 65,323	$ 160,975	$ 378,629	$ 408,678
11	Difference (Line 9-10)	241	873	2,936	8,702	22,386	41,978
12	Effective Tax Rate (c)	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%	35.0000%
13	ADIT (Line 11*12)	$ 84	$ 305	$ 1,027	$ 3,046	$ 7,835	$ 14,692

Line No	**State Tax Depreciation**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
	2008						
	In-Service Adds	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647	$ 9,647
	MACRS Rate	3.750%	7.219%	6.677%	6.177%	5.713%	5.285%
14	Total Depreciation	$ 362	$ 696	$ 644	$ 596	$ 551	$ 510
	2009						
	In-Service Adds		$ 7,048	$ 7,048	$ 7,048	$ 7,048	$ 7,048
	MACRS Rate		3.750%	7.219%	6.677%	6.177%	5.713%
15	Total Depreciation		$ 264	$ 509	$ 471	$ 435	$ 403
	2010						
	In-Service Adds			53,094	53,094	53,094	53,094
	MACRS Rate			3.750%	7.219%	6.677%	6.177%
16	Total Depreciation			$ 1,991	$ 3,833	$ 3,545	$ 3,280
	2011						
	In-Service Adds				104,469	104,469	104,469
	MACRS Rate				3.750%	7.219%	6.677%
	Total Depreciation				$ 3,918	$ 7,542	$ 6,975
	2012						
	In-Service Adds					238,678	238,678
	MACRS Rate					3.750%	7.219%
	Total Depreciation					$ 8,950	$ 17,230
	2013						
	In-Service Adds						60,724
	MACRS Rate						3.750%
	Total Depreciation						$ 2,277
17	Total Yearly Depreciation	$ 362	$ 961	3,144	$ 8,817	$ 21,024	$ 30,675

Notes:
(a) Previous year line 3 + Current year line 2.
(b) Previous year line 7 + Current year line 6.
(c) 2007 effective tax rate used as an estimate for all years
(d) Minor variances due to rounding

Record Request 7

Request:

Referring to the response Division Data Request 2-9, please quantify the amount of the under-recovery associated with the prior period adjustment associated with the FERC order issued in March 2008 in ER04-157 re-setting and increasing by 24 basis points the base ROE applied to all transmission facilities in New England effective as of February 1, 2005.

Response:

Estimated impact to Narragansett in 2008 was approximately $1 million. Please see the attached for further detail.

Estimated Impact of Increase in ROE of 24 basis points on Narragansett Electric
($ 000's)

		2005	2006	2007	2008 (*)	Total	Sources:
Section I:							
	PTF Impact						
	Narragansett Specific Impact					758.4	Per ISO-NE Surcharge Report
Section II:							
	Non-PTF Impact						
1	NEP: Actual Ratebase as of December 31 of each year	549,711.6	633,715.2	762,529.3	777,807.7		Schedule 21-NEP Monthly Rev. Requirements
2	December 31, Equity Ratio	65%	65%	62%	63%		Schedule 21-NEP Monthly Rev. Requirements
3	Increase in Equity Rate (24 basis points)	0.24%	0.24%	0.24%	0.24%		Per FERC Order
4	Estimated Annual Impact	851.22	986.27	1,143.45	1,184.31		Line 1 * Line 2 * Line 3
5	Estimated Non-PTF Percentage	30%	30%	30%	30%		Historical Estimate
6	Total New England Power Company Non-PTF Impact	255.37	295.88	343.03	355.29		Line 4 * Line 5
7	Allocation of Non-PTF to Narragansett Electric @26%	66.4	76.9	89.2	92.4		Line 6 * 25% (Narragansett Share of NEP's Non-PTF Costs)
8	Adjusted Non-PTF impact for number of Months in effect	60.9	76.9	89.2	92.4	319.4	Uses 11/12 of 2005 Line 7 figure
Section III: Total 2008 impact of 24 basis point ROE adjustment						$\boxed{\textbf{1,077.8}}$	

(*) 2008 used March 31, 2008 Ratebase figure