KEEGAN, WERLIN & PABIAN, LLP

ATTORNEYS AT LAW
265 FRANKLIN STREET
BOSTON, MASSACHUSETTS 02110-3113

(617) 951-1400

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

June 29, 2004

Mary L. Cottrell, Secretary
Department of Telecommunication and Energy
One South Station, 2nd Floor
Boston, MA 02202

Re: D.T.E. 04-60 — Petition of Cambridge Electric Light Company and Commonwealth Electric Company for Approvals Relating to the Termination of Power Purchase Agreements with Pittsfield Generating Company, L.P.

Dear Secretary Cottrell:

Enclosed is an original and nine copies of the Petition for Approvals Relating to Termination of Purchase Power Agreements (the "Petition"), with accompanying testimony and supporting exhibits, submitted by Cambridge Electric Light Company ("Cambridge") and Commonwealth Electric Company ("Commonwealth"), d/b/a NSTAR Electric ("NSTAR Electric"). The Petition requests approval of: (1) the buyout and termination of Cambridge's and Commonwealth's respective existing Power Purchase Agreements (the "Existing Pittsfield PPAs") with Pittsfield Generating Company, L.P. (formerly known as Altresco Pittsfield, L.P.) ("Pittsfield"); and (2) ratemaking treatment associated with the costs .

NSTAR Electric is seeking Department of Telecommunications and Energy (the "Department") approval of two Termination Agreements (one for Cambridge; one for Commonwealth) (the "Pittsfield Termination Agreements") to effect the buyout and termination of the Existing Pittsfield PPAs. The Pittsfield Termination Agreements will result in customer savings of approximately $6 million on a net-present-value basis. NSTAR Electric is also proposing that the significant customer savings relating to the Pittsfield Termination Agreements be returned to customers through the Variable Component of each company's Transition Charge. In support of the Petition, NSTAR Electric has enclosed the following:

Exhibit NSTAR-GOL	Prefiled testimony of Geoffrey O. Lubbock (with accompanying exhibits), Vice President, Financial Strategic Planning & Policy, regarding the Pittsfield Termination Agreements and related customer savings (the "Lubbock Testimony"); and

Exhibit NSTAR-RBH	Prefiled testimony of Robert B. Hevert (with accompanying exhibits), President of Concentric Energy Advisors, Inc. ("CEA"), to discuss the specifics of the auction that resulted in the execution of the Pittsfield Termination Agreements (the "Hevert Testimony").

The Pittsfield Termination Agreements set forth herein culminate an almost year-long process undertaken by NSTAR Electric to lower rates for their customers by mitigating transition costs of above-market PPAs via an open and competitive auction process (the "2003 Auction"). As described in Mr. Hevert's testimony, the 2003 Auction provided market participants open and non-discriminatory access to all relevant information and was a competitive process that has resulted in the maximum possible mitigation of transition costs.

Also enclosed is a Motion for Protective Treatment of certain price forecasts and financial information that are included in the analysis of customer savings associated with the Pittsfield Termination Agreements. These forecasts were procured from a third-party vendor and are proprietary to the vendor. In addition, because negotiations have not been concluded regarding all outstanding PPAs, this information is deemed proprietary and confidential, since the public release of this information could adversely affect NSTAR Electric's ability to maximize mitigation. The exhibits accompanying this public version of the filing are redacted to remove the confidential information. Unredacted versions are being provided separately, under seal.

The Pittsfield Termination Agreements anticipate an Effective Date of October 1, 2004. Accordingly, in order for customers to realize the benefits of the Pittsfield Termination Agreements at the earliest possible date, NSTAR Electric requests that the Department issue an order approving the Pittsfield Termination Agreements by September 7, 2004, which would allow for the tolling of the statutory appeal period plus three business days (as provided in Section 2.1 of the Pittsfield Termination Agreements) between the issuance of the Department's order and October 1, 2004.

Also enclosed is the $100 filing fee. Thank you for your attention to this matter.

Sincerely,

Robert N. Werlin

Enclosures

cc: Andrew O. Kaplan, General Counsel
Ronald LeComte, Director, Electric Power Division
Kevin Brannelly, Director, Rates and Revenue Requirements Division
Joseph Rogers, Assistant Attorney General
Kerry Britland
Tam Ly

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Petition of Cambridge Electric Light Company and Commonwealth Electric Company for Approvals Relating to the Termination of Purchase Power Agreements with Pittsfield Generating Company, L.P.	)	D.T.E. 04-60

PETITION FOR APPROVALS RELATING TO TERMINATION OF PURCHASE POWER AGREEMENTS

1. Cambridge Electric Light Company ("Cambridge") and Commonwealth Electric Company ("Commonwealth") (collectively, the "Petitioners") hereby petition the Department of Telecommunications and Energy (the "Department"), pursuant to G.L. c. 164, §§ 1A, 1G, 76, 94, and 94A, for approval of: (a) the Termination Agreements between: (1) Cambridge and Pittsfield Generating Company, L.P. (formerly known as Altresco Pittsfield, L.P.) ("Pittsfield"); and (2) Commonwealth and Pittsfield (collectively, the "Pittsfield Termination Agreements"); and (b) approval of ratemaking treatment relating to the Pittsfield Termination Agreements.

2. Cambridge is a Massachusetts corporation authorized to generate, transmit, purchase, sell, and distribute electricity, and is subject to the regulatory jurisdiction of the Department. Cambridge provides retail electric service to approximately 44,000 customers in the City of Cambridge.

3. Commonwealth is a Massachusetts corporation authorized to generate, transmit, purchase, sell, and distribute electricity, and is subject to the regulatory jurisdiction of the Department. Commonwealth provides retail electric service to approximately 318,000 customers in 40 communities in southeastern Massachusetts, Cape Cod and Martha's Vineyard.

4. Cambridge and Pittsfield are parties to a Power Purchase Agreement dated February 20, 1992, as amended on November 7, 1994 and November 21, 1996 (the "Cambridge/Pittsfield PPA"), pursuant to which Pittsfield sells to Cambridge, and Cambridge purchases from Pittsfield, electricity produced by Pittsfield's generation facility located in Pittsfield, Massachusetts (the "Pittsfield Facility"). The term of the Cambridge/Pittsfield PPA runs through December 31, 2011.

5. Commonwealth and Pittsfield are parties to a Power Purchase Agreement dated February 20, 1992, as amended on November 7, 1994 and November 21, 1996 (the "Commonwealth/Pittsfield PPA") pursuant to which Pittsfield sells to Cambridge, and Cambridge purchased from Pittsfield, electricity produced by Pittsfield Facility. The term of the Commonwealth/Pittsfield PPA runs through December 31, 2011.

6. As a result of the recently completed competitive solicitation (the "2003 Auction") conducted by Boston Edison, Commonwealth and Cambridge Electric Light Company d/b/a NSTAR Electric ("NSTAR Electric") of their PPA entitlements, including the Cambridge/Pittsfield PPA and the Commonwealth/Pittsfield PPA (together, the "Existing Pittsfield PPAs"), the Existing Pittsfield PPAs will be bought out pursuant to the terms of the Pittsfield

Termination Agreements. The Pittsfield Termination Agreements for Cambridge and Commonwealth were executed on June 2, 2004, and are attached hereto as Appendices A and B, respectively.

7. In support of this Petition, the Petitioners attach the following exhibits:

Exhibit NSTAR-GOL	Prefiled testimony of Geoffrey O. Lubbock (with accompanying exhibits), Vice President, Financial Strategic Planning & Policy, regarding the Pittsfield Termination Agreement and related customer savings (the "Lubbock Testimony").
Exhibit NSTAR-RBH	Prefiled testimony of Robert B. Hevert (with accompanying exhibits), President of Concentric Energy Advisors, Inc. ("CEA"), to discuss the specifics of the 2003 Auction that resulted in the execution of the Pittsfield Termination Agreements (the "Hevert Testimony").

8. Approval of the Pittsfield Termination Agreements and associated ratemaking treatment is requested pursuant to G.L. c. 164, §§ 1A, 1G, 76, 94, and 94A as being in the public interest and the product of all reasonable steps taken to mitigate, to the maximum extent possible, the transition costs relating to the Existing Pittsfield PPAs. The transaction meets this requirement in that the 2003 Auction and the Pittsfield Termination Agreements are consistent with the Chapter 164 of the Acts of 1997 (the "Act"), and Cambridge's and Commonwealth's Restructuring Plan approved by the Department in Cambridge Electric Light Company/Canal Electric Company/Commonwealth Electric Company, D.P.U./D.T.E. 97-111 (the "Restructuring Plan").

9. The Existing Pittsfield PPAs were offered for sale in a public auction. The 2003 Auction was conducted in an open and competitive manner and was otherwise equitable and maximized the value of the assets that were subject to the auction, pursuant to G.L. c. 164, § 1A(b)(1).

10. The Petitioners selected CEA, a nationally prominent economic advisory firm, to help conduct the 2003 Auction.

11. In conducting the auction, NSTAR Electric and CEA used a fair, unbiased, confidential and competitive process, whereby bidders had the ability and opportunity to maximize the value of their respective bids through complete, uninhibited and non-discriminatory access to all data. The auction process is described in detail in the Hevert Testimony.

12. Pursuant to the Pittsfield Termination Agreements, the Existing PPAs would terminate upon the date that certain conditions have been satisfied (the "Effective Date"), and the Petitioners would be relieved of any obligations to purchase or accept electricity produced by the Pittsfield Facility, and Pittsfield would have no obligation to sell electricity to the Petitioners. The Petitioners would remain obligated to make payments to Pittsfield for electricity or capacity supplied to the Petitioners at any time up to the Effective Date and Pittsfield would remain obligated to make any refunds relating to such payments. In consideration of the termination of the Existing Pittsfield PPAs, the Petitioners will pay to Pittsfield certain monthly payments through December 1, 2008 (the "Termination Payments"). Details regarding the Pittsfield Termination Agreements are presented in Mr. Lubbock's testimony.

13. Compared to the Existing Pittsfield PPAs, the Pittsfield Termination Agreements will result in approximately $6 million of customer savings, on a net present value ("NPV") basis. The customer savings are quantified in Exhibits NSTAR-CAM-GOL-2 and NSTAR-COM-GOL-2, presented by Mr. Lubbock. The savings are determined by comparing: (a) the NPV of Transition-Cost payments by customers that would have been made if the Existing Pittsfield PPAs were to remain in effect to (b) the NPV of Transition-Cost payments by customers that will be made if the Pittsfield Termination Agreements are approved by the Department.

14. These significant savings will be passed on to the Petitioners' customers through the respective Transition Charges of Cambridge and Commonwealth. Costs associated with the Existing Pittsfield PPAs have been approved for recovery through the Variable Portion of the Transition Costs of Cambridge and Commonwealth. The Petitioners propose to recover costs relating to the Pittsfield Termination Agreements through the Variable Component of Cambridge's and Commonwealth's respective Transition Charges. The application of the savings relating to the Pittsfield Termination Agreements is presented in Mr. Lubbock's testimony.

15. G.L. c. 164, §§ 1A and 1G require electric companies to seek to mitigate transition costs, including, as one mitigation method, the buyout of above-market power-purchase contracts. G.L. c. 164, § 1G(d)(1) and (2).

16. In reviewing power contract buyouts, buydowns and renegotiations, the Department generally considers the consistency of the proposed transactions with a company's Department-approved restructuring plan or settlement and the

Restructuring Act in that the "sale process is equitable and maximizes the value of the existing generation facilities being sold." G.L. c. 164, § 1A(b)(1).

17. Consistent with the Act, Cambridge's and Commonwealth's Restructuring Plan requires that each company undertake all reasonable steps to mitigate its transition costs and encourages the company to divest its non-nuclear generating assets. The Department has previously found that Commonwealth is committed to full mitigation of its transition costs, "principally by auctioning off...PPAs and generating plants" in compliance with the Act. D.P.U./D.T.E. 97-111, at 64.

18. The Pittsfield Termination Agreements should be approved by the Department because, consistent with the Act's requirements regarding the renegotiation of PPAs, the Pittsfield Termination Agreements are both: (1) likely to achieve savings to customers; and (2) are otherwise in the public interest. Given the estimated savings of approximately $6 million on an NPV basis relating to the Pittsfield Termination Agreements and the fact that the savings will be passed on to customers, customers would realize an extraordinary level of savings. Moreover, renegotiating PPAs is consistent with the Act and Cambridge's and Commonwealth's Restructuring Plan and therefore, approval of the Pittsfield Termination Agreements is in the public interest. Accordingly, the Pittsfield Termination Agreements are reasonable and consistent with the Department's standard of review for buyout or buydown agreements. Therefore, the Department should review and approve the Pittsfield Termination Agreements expeditiously so that the customers of Cambridge and Commonwealth may realize the significant amount of savings relating to the Pittsfield Termination Agreements.

WHEREFORE, Cambridge and Commonwealth respectfully request the Department to approve the Pittsfield Termination Agreements, and the Petitioners request that the Department make the following findings:

A. The 2003 Auction was conducted consistent with Cambridge's and Commonwealth's Restructuring Plan in that the auction was equitable and maximized the value of the assets that were subject to the auction, pursuant to G.L. c. 164, § 1A(b)(1).

B. The Pittsfield Termination Agreements are consistent with the Act and maximize the mitigation of Cambridge's and Commonwealth's respective transition costs.

C. The Pittsfield Termination Agreements are reasonable, are in the public interest and are consistent with the requirements of G.L. c. 164, § 1G(d)(2)(ii).

D. The proposed ratemaking treatment for the above-market portion of the Pittsfield Termination Agreements is consistent with the Restructuring Plan, the Act, G.L. c. 164, § 1G(b)(1) and G.L. c. 164, §§76, 94 and 94A.

E. The Petitioners also respectfully request that the Department grant any other approvals and make any other findings that may be necessary or appropriate to approve the Pittsfield Termination Agreements as described herein.

The Petitioners respectfully request a decision from the Department on an expedited basis.

Respectfully submitted,

CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY

By Their Attorneys,

Robert N. Werlin, Esq.
John K. Habib, Esq.
Keegan, Werlin & Pabian, LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400 (telephone)
(617) 951-1354 (facsimile)

Dated: June 29, 2004

APPENDIX A

TERMINATION AGREEMENT

This TERMINATION AGREEMENT (this "Agreement") is entered into on the 2nd day of June, 2004, by and between CAMBRIDGE ELECTRIC LIGHT COMPANY, a Massachusetts corporation having its principal place of business at 800 Boylston Street, Boston, Massachusetts 02199 ("Cambridge"), and PITTSFIELD GENERATING COMPANY, L.P. (f/k/a Altresco Pittsfield, L.P.) , a Delaware limited partnership with a principal place of business at 235 Merrill Road, Pittsfield, Massachusetts ("Pittsfield").

W I T N E S S E T H:

WHEREAS, Cambridge and Pittsfield are parties to that certain Power Sale Agreement, dated February 20, 1992, as amended by an Amendment to Power Sale Agreement dated as of November 7, 1994 and a Second Amendment to Power Purchase Agreement dated as of November 21, 1996 (as so amended, the "Power Purchase Agreement"), pursuant to which Pittsfield sells to Cambridge, and Cambridge purchases from Pittsfield, a seventeen and two-tenths per cent (17.2%) entitlement to the capacity and associated electric energy produced by Pittsfield's facility situated in Pittsfield, Massachusetts (the "Facility"); and

WHEREAS, Pittsfield and Cambridge desire to terminate the Power Purchase Agreement pursuant to, and in accordance with, the terms and provisions contained herein.

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the parties hereto hereby agree as follows:

1. **Definitions.** Capitalized terms used herein without definition shall have the respective meanings given to such terms in the Power Purchase Agreement. In addition, the term "Business Day" shall mean a day other than a Saturday, Sunday or any other day which is a legal holiday or a day on which banking institutions are authorized or required by law to close or be closed in Massachusetts.

2. **Effectiveness.**

2.1. The "Effective Date" shall be the third Business Day after the first date on which all of the following conditions have been satisfied: (i) approval by the Massachusetts Department of Telecommunications and Energy ("DTE"), in form and substance reasonably satisfactory to the parties, of (A) this Agreement, including but not limited to the termination of the Power Purchase Agreement pursuant to the terms hereof, and (B) the full recovery of the Termination Payments through Cambridge's Transition Charge (as defined under G.L. c. 164, Section 1G), and either (x) the expiration of any appeal periods applicable to such DTE approval, or (y) if an appeal of such approval is filed within any such applicable appeal period, the issuance of a final ruling denying such appeal or resolving such appeal on terms acceptable to both parties (collectively, the "Cambridge Approvals"); (ii) notice of termination (the "FERC Notice") of the Power

Purchase Agreement is provided by Pittsfield to the Federal Energy Regulatory Commission ("FERC") consistent with FERC's requirements therefore and such FERC Notice becomes effective; (iii) Cambridge and Pittsfield shall have given (or been deemed to have given) notice that the Cambridge Approvals are acceptable pursuant to Section 2.2; and (iv) Cambridge and Pittsfield shall have given (or been deemed to have given) notice that the final order or other determination approving, disapproving or ruling in any way on the FERC Notice is acceptable pursuant to Section 2.3; provided, however, that notwithstanding satisfaction of the foregoing conditions, the Effective Date shall be no earlier than October 1, 2004. Notwithstanding the foregoing, this Agreement shall terminate and be of no further force or effect whatsoever (including, without limitation, the provisions of Sections 3, 4, and 5 hereof) as provided in Section 7.

2.2. No later than five (5) Business Days after the issuance by DTE or any appellate court or other judicial body with jurisdiction over the DTE, of any order or other determination approving, disapproving or ruling in any way on this Agreement, Cambridge shall provide Pittsfield with: (i) written notice of such order or determination including a copy thereof; and (ii) certification of an authorized officer of Cambridge as to whether such order or determination is reasonably acceptable to Cambridge. No later than five (5) Business Days after receipt of such notice and documentation, Pittsfield shall provide Cambridge with a certification of an authorized officer of Pittsfield as to whether such order or determination is reasonably acceptable to Pittsfield. Failure by either party to provide such written certification within five (5) Business Days of a written request by the other party shall constitute certification that such order or determination is reasonably acceptable to such party.

2.3 No later than five (5) Business Days after the issuance by FERC or any appellate court or other judicial body with jurisdiction over the FERC, of any order or other determination approving, disapproving or ruling in any way on the termination of the Power Purchase Agreement, Pittsfield shall provide Cambridge with: (i) written notice of such order or determination including a copy thereof any; and (ii) certification of an authorized officer of Pittsfield as to whether such order or determination is reasonably acceptable to Pittsfield. No later than five (5) Business Days after receipt of such notice and documentation, Cambridge shall provide Pittsfield with a certification of an authorized officer of Cambridge as to whether such order or determination is reasonably acceptable to Cambridge. Failure by either party to provide such written certification within five (5) Business Days of a written request by the other party shall constitute certification that such order or determination is reasonably acceptable to such party.

3. Termination of Agreements.

3.1. Agreement to Terminate. Pittsfield and Cambridge hereby agree that, effective as of 12:00:01 am eastern time on the Effective Date, the Power Purchase Agreement shall be deemed terminated without any further action being required on the part of either Cambridge or Pittsfield, provided that Pittsfield has received confirmation of the transfer of the initial Termination Payment to be made pursuant to Section 4 of this Agreement. Upon such termination: (i) Cambridge shall have no obligation whatsoever under the Power Purchase Agreement, including, without limitation, any obligation to purchase or accept electric energy or capacity produced by the Facility, and (ii) Pittsfield shall have no obligation whatsoever under the Power Purchase Agreement, including, without limitation, any obligation to sell to Cambridge any electric energy or capacity produced by the Facility. Notwithstanding the preceding sentence and said termination of the Power Purchase Agreement: (a) Cambridge shall remain obligated to make payments to Pittsfield pursuant to the terms of the Power Purchase Agreement on account of any electric energy and capacity produced by the Facility and supplied to Cambridge at any time up to the Effective Date ("PPA Payments"), to the extent that any such amounts remain unpaid on the Effective Date; and (b) Pittsfield shall remain obligated to make any PPA Refunds. "PPA Refunds" shall be any amounts owed by Pittsfield to Cambridge pursuant to the terms of the Power Purchase Agreement on account of adjustments or reconciliations resulting from errors in measuring, or calculating charges for, energy or capacity delivered by Pittsfield to Cambridge at any time up to the Effective Date that Cambridge provides notice of no later than ninety (90) days after the Effective Date. Any disputes regarding PPA Payments and/or PPA Refunds shall be resolved pursuant to the terms of the Power Purchase Agreement. The parties agree to cooperate with each other in taking any and all actions that may be reasonably requested by the other in order to facilitate the approval of this Agreement by the DTE and, if this Agreement is approved by the DTE in for and substance acceptable to the parties, the termination of the Power Purchase Agreement.

3.2. Release of Liens. On the Effective Date, Cambridge shall release and discharge any and all mortgages, security interests, letters of credit and/or other liens (collectively, "Liens") that it may have on or with respect to the Facility or Pittsfield, including without limitation: (a) the Agreement in Lieu of Second Mortgage dated as of March 20, 1992 among Cambridge, Pittsfield and certain other parties; (b) the Declaration of Easements, Covenants and Restrictions made by Pittsfield and the owner participant under Pittsfield's lease financing dated March 20, 1992; and (c) the Accommodation Agreement dated as of March 20, 1992 among Pittsfield, Cambridge and certain other parties. Cambridge shall execute and deliver any and all documents and take any further actions that Pittsfield may reasonably request in order to effectively release and discharge all of such Liens.

4. Payments by Cambridge.

4.1 Termination Payments. For and in consideration of Pittsfield's agreement to terminate the Power Purchase Agreement, Cambridge shall pay, and hereby promises to pay, to the order of Pittsfield the following monthly payment amounts (collectively, the "Termination Payments", and individually, each monthly payment a "Termination Payment"); provided that the first Termination Payment shall be due on the Effective Date and shall be equal to (x) the monthly payment amount owed for the month in which the Effective Date occurs multiplied by (y) a fraction, the numerator of which is the number of days remaining in such month (including the Effective Date) and the denominator of which is the number of days in such month.

Calendar Year During Which Termination Payment is Owed	Termination Payment Amount
2004	$835,000
2005	$1,252,500
2006	$417,500
2007	$835,000
2008	$835,000

After the Effective Date, Cambridge shall make Termination Payments on the first Business Day of each calendar month beginning with the month following the month in which the Effective Date occurs and continuing through and including December 1, 2008. Each Termination Payment shall be made by wire transfer to an account designated in writing from time to time by Pittsfield.

4.2 Unconditional Obligation. Cambridge's obligations to make each Termination Payment when due under this Agreement are subject to the terms and conditions set forth in this Agreement and are otherwise absolute, unconditional and irrevocable and are not subject to cancellation, termination, modification, repudiation, excuse or substitution by Cambridge. Cambridge is not entitled to any abatement, reduction, offset, defense or counterclaim with respect to the obligations to make each Termination Payment when due under this Agreement for any reason whatsoever.

4.3 PPA Payments. Cambridge shall pay Pittsfield for: (a) all energy delivered up to the Effective Date; and (b) any other charges owed by Cambridge pursuant to the Power Purchase Agreement with respect to the month in which the Effective Date occurs, which charges shall be prorated based on the number of days in such month during which the Purchase Power Agreement was in effect.

5. Releases.

5.1. Releases by Cambridge. Effective as of midnight on the Effective Date, Cambridge, for itself, its successors and assigns, hereby releases and forever discharges Pittsfield, the general and limited partners of Pittsfield, all of the officers, directors, employees and agents of Pittsfield and all of the partners, officers, directors, employees

and agents of the general or limited partners of Pittsfield (collectively, for purposes of this Section 5.1, the "Pittsfield Released Parties") from any and all claims, demands, actions, causes of action, accounts, covenants, contracts, torts, agreements, obligations, debts, suits, judgments, executions, sums, damages, or liabilities whatsoever in law or equity, whether known or unknown to Cambridge, which Cambridge, its successors and assigns ever had, now have or may ever have for, upon or by reason of any matter, cause, circumstance or fact whatsoever existing at any time from the beginning of the world to and including the Effective Date, against any and all of the Pittsfield Released Parties related to or arising under the Power Purchase Agreement; provided, however, that Cambridge does not hereby release Pittsfield from: (i) any of Pittsfield's obligations under this Agreement; or (ii) any of Pittsfield's obligations to pay PPA Refunds.

5.2. Release by Pittsfield. Effective as of midnight on the Effective Date, Pittsfield, for itself, its successors and assigns, hereby releases and forever discharges Cambridge and its officers, directors, employees and agents (collectively, for purposes of this Section 5.2, the "Cambridge Released Parties") from any and all claims; demands, actions, causes of action, accounts, covenants, contracts, torts, agreements, obligations, debts, suits, judgments, executions, sums, damages, or liabilities whatsoever in law or equity, whether known or unknown to Pittsfield, which Pittsfield, its successors and assigns ever had, now have or may ever have for, upon or by reason of any matter, cause, circumstance or fact whatsoever existing at any time from the beginning of the world to and including the Effective Date, against any and all of the Cambridge Released Parties related to or arising under the Power Purchase Agreement; provided, however, that Pittsfield does not hereby release Cambridge from: (i) any of Cambridge's obligations under this Agreement; or (ii) any of Cambridge's obligations to pay PPA Payments.

6. Consent of Regulatory Bodies.

6.1 Consent of the DTE. Cambridge shall: (i) within thirty (30) days of the date of this Agreement file a copy of this Agreement with the DTE together with a request for approval of the same; (ii) exercise all commercially reasonable efforts to obtain an expedited review by the DTE of this Agreement and the termination of the Power Purchase Agreement pursuant hereto; and (iii) exercise all commercially reasonable efforts to secure the DTE's approval of this Agreement, the termination of the Power Purchase Agreement, and the full recovery of the Termination Payments through Cambridge's Transition Charge. Cambridge agrees to provide Pittsfield with a draft of the proposed request for approval of this Agreement to be filed with the DTE at least five (5) days prior to its submission to the DTE, to consider modifications to such request that are suggested by Pittsfield, and to generally consult with Pittsfield prior to filing such request; provided that the draft provided Cambridge may exclude: (a) competitive, proprietary or confidential information relating to other power purchase agreements; and (b) information relating to the Power Purchase Agreement which is being submitted to the DTE on a confidential basis. Pittsfield hereby agrees to diligently cooperate with, to not oppose or protest, and to use all commercially reasonable efforts to assist Cambridge with respect to the Cambridge Approvals, said cooperation and commercially reasonable efforts to include, without limitation: (i) providing any information or supporting

documentation as may be reasonably required to establish to the satisfaction of the DTE that the payment to be made hereunder is reasonable and prudent; and (ii) making its employees or agents reasonably available for any appearance before the DTE that may be required by the DTE.

6.2 Notice to FERC. Pittsfield shall: (i) within thirty (30) days of the date of this Agreement, file the FERC Notice in accordance with FERC regulations and procedures; and (ii) exercise all commercially reasonable efforts to secure that FERC deems such notice effective as of the earliest date feasible. Pittsfield agrees to provide Cambridge with a draft of the proposed FERC Notice at least five (5) days prior to its submission to the FERC, to consider modifications to such FERC Notice that are suggested by Cambridge, and to generally consult with Cambridge prior to filing such notice. Cambridge hereby agrees to diligently cooperate with, to not oppose or protest, and to use all commercially reasonable efforts to assist Pittsfield with respect to the FERC Notice, said cooperation and commercially reasonable efforts to include, without limitation, providing any information or supporting documentation as may be reasonably required by Pittsfield.

7. Termination; Remedies.

7.1 Pittsfield may terminate this Agreement on written notice to Cambridge if the Effective Date has not occurred by January 3, 2005.

7.2 Cambridge may terminate this Agreement on written notice to Pittsfield if, despite Cambridge's compliance with Section 6, the Effective Date has not occurred by January 3, 2005.

7.3 Upon any termination under Section 7.1 or 7.2: (i) this Agreement shall terminate and be of no further force or effect whatsoever (including, without limitation, the provisions of Sections 3, 4, and 5 hereof); and (ii) each of the Power Purchase Agreement, and the Liens shall continue in full force and effect and shall remain the valid and binding obligation of each party thereto enforceable against each such party in accordance with their terms.

7.4 Without limiting other remedies available to Pittsfield or Cambridge, if Cambridge fails to make any Termination Payment or other payments required pursuant to this Agreement, as and when such payments are due in accordance with the terms hereof interest shall accrue on any such unpaid amounts at an annual rate of interest equal to the prime rate of interest on commercial loans then in effect at Bank of America plus six hundred (600) basis points, compounded daily. In addition, to the extent any such amounts remain unpaid for a period of ten (10) Business Days following notice of such failure by Pittsfield, Cambridge shall be obligated to post security in the form of a segregated cash collateral account or a letter of credit in form and substance and held by an agent or issued by an issuer, as applicable, reasonably acceptable to Pittsfield, in an amount equal to two (2) Termination Payments (i.e., $1,670,000). Such security shall be available for drawing by Pittsfield in an amount or amounts equal to overdue sums

(including interest thereon) owed by Cambridge; provided that in the event Pittsfield makes a drawing of any such security as permitted hereunder, Cambridge shall replenish the amount of such security to the value specified above. In addition, if Pittsfield incurs any costs (including but not limited to internal costs and attorneys' fees) in order to collect overdue amounts owed hereunder (other than PPA Payments) or to enforce its right to obtain security as provided herein, Cambridge shall reimburse Pittsfield for any reasonable costs incurred in connection with such collection efforts no later than ten (10) days after submission by Pittsfield of any invoice accompanied by reasonable supporting documentation.

8. Facility Status. After the Effective Date, Pittsfield, at its sole discretion, may sell, modify, close, or utilize the Facility for sales to others.

9. Stay. As of the date of this Agreement, any and all notices of any breaches, events of default or disputes under the Power Purchase Agreement shall be stayed, without prejudice. The parties agree further not to submit any such notices unless and until this Agreement is terminated. Nothing contained herein shall prejudice either party's right to pursue any claim(s) arising after the date of this Agreement for PPA Payments or PPA Refunds, or any claim so stayed to the extent this Agreement is terminated.

10. Representations and Warranties.

10.1 Cambridge's Representations and Warranties. Cambridge represents and warrants to Pittsfield that:

(A) It has all requisite power and authority (including full corporate power and legal authority) to execute and deliver this Agreement, and subject to receipt of the Cambridge Approvals, to perform its obligations hereunder;

(B) All necessary action has been taken to authorize the execution, delivery and performance by Cambridge of this Agreement and this Agreement constitutes the valid, legal, and binding commitment of Cambridge and is fully enforceable against Cambridge in accordance with the terms hereof;

(C) Cambridge's execution, delivery, and performance of this Agreement have been duly authorized by or are in accordance with its corporate charter, bylaws, and other organizational documents and constitutes Cambridge's legal, valid, and binding obligation;

(D) The person executing this Agreement is duly authorized to do so by Cambridge's governing body;

(E) There is no action, suit or proceeding, at law or in equity, nor is there any official investigation pending or, to the best of Cambridge's knowledge, threatened against Cambridge wherein an unfavorable decision, ruling or finding would adversely affect the performance by Cambridge of its obligations hereunder or which, in any way, calls into question or may adversely and materially affect the validity or enforceability of this Agreement;

(F) Subject to Cambridge's obtaining the Cambridge Approvals and Pittsfield's proper filing of the FERC Notice, neither the execution or delivery of this Agreement nor performance by Cambridge of the transactions contemplated hereby will: (1) conflict with or violate any provision of Cambridge's corporate charter or bylaws; or (2) conflict with, violate or result in a breach of any duty under any applicable constitution, law, judgment, regulation, or order of any governmental authority;

(G) Except for the Cambridge Approvals and FERC Notice, no approval, authorization, order or consent of, or declaration, registration or filing with any governmental authority is required for the valid execution, delivery and performance of this Agreement by Cambridge; and

(H) Cambridge's execution, delivery and performance of this Agreement will not result in a breach or violation of, or constitute a default under, any agreement, lease, or instrument to which it is a party or by which it is bound as of the date hereof.

10.2 Pittsfield's Representations and Warranties. Pittsfield represents and warrants to Cambridge that:

(A) It has all requisite power and authority (including full corporate power and legal authority) to execute and deliver this Agreement, and, subject to the effectiveness of the FERC Notice, to perform its obligations hereunder;

(B) All necessary action has been taken to authorize the execution, delivery and performance by Pittsfield of this Agreement and this Agreement constitutes the valid, legal, and binding commitment of Pittsfield and is fully enforceable against Pittsfield in accordance with the terms hereof;

(C) Pittsfield's execution, delivery, and performance of this Agreement have been duly authorized by or are in accordance with its corporate charter, bylaws, and other organizational documents and constitutes Pittsfield's legal, valid, and binding obligation;

(D) The person executing this Agreement is duly authorized to do so by Pittsfield's governing body;

(E) There is no action, suit or proceeding, at law or in equity, nor is there any official investigation pending or, to the best of Pittsfield's knowledge, threatened against Pittsfield wherein an unfavorable decision, ruling or finding would adversely affect the performance by Pittsfield of its obligations hereunder or which, in any way, calls into question or may adversely and materially affect the validity or enforceability of this Agreement;

(F) Neither the execution or delivery of this Agreement nor performance by Pittsfield of the transactions contemplated hereby will: (1) conflict with or violate any provision of Pittsfield's corporate charter or bylaws; or (2) conflict with, violate or result in a breach of any duty under any applicable constitution, law, judgment, regulation, or order of any governmental authority;

(G) No approval, authorization, order or consent of, or declaration, registration or filing with any governmental authority is required for the valid execution, delivery and performance of this Agreement by Pittsfield, except for the filing of the FERC Notice; and

(H) Pittsfield's execution, delivery and performance of this Agreement will not result in a breach or violation of, or constitute a default under, any agreement, lease, or instrument to which it is a party or by which it is bound as of the date hereof.

11. Miscellaneous.

11.1. No Waiver. No failure on the part of any party to exercise, and no delay in exercising, any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any single or partial exercise by any party of any right, remedy or power hereunder preclude any other or future exercise of any other right, remedy or power.

11.2. Severability. In the event any provision of this Agreement that is not material shall for any reason be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not effect any other term or provision hereof.

11.3. Entire Agreement; Amendment. This Agreement contains the entire understanding of the parties, supersedes all prior agreements and understandings relating to the subject matter hereof, and shall not be amended, modified or terminated except by a written instrument hereafter signed by all of the parties hereto.

11.4. Sections and Section Headings. The headings of any of the sections and subsections are for reference only and shall not limit or control the meaning thereof.

11.5. Governing Law. The validity and construction of this Agreement shall be governed by the internal laws (and not the choice-of-law rules) of the Commonwealth of Massachusetts.

11.6 Binding Effect; Assignment. All terms of this Agreement shall be binding upon and inure to the benefit of and be enforceable by the respective successors and assigns of the parties hereto. Neither party shall have the right to assign this Agreement or any right, obligation or privilege hereunder without first obtaining the consent of the other party hereto; provided that: (i) Pittsfield shall have the right to assign its right to receive the Termination Payments, provided that any such assignee shall confirm in writing that it is taking such assignment subject to the terms of this Agreement; (ii) Pittsfield shall have the right to assign this Agreement at any time after the deadline for Cambridge to claim any PPA Refunds shall have expired and either: (a) Cambridge shall not have claimed any PPA Refunds, (b) Pittsfield shall have paid all PPA Refunds claimed by Cambridge or determined to be owed to Cambridge; or (c) Pittsfield shall have posted an irrevocable letter of credit in favor of Cambridge, and in form and substance reasonably acceptable to Cambridge, in the amount of any PPA Refunds claimed by Cambridge; and (iii) Cambridge shall have the right to assign this Agreement to a wholly-owned subsidiary of NSTAR that is a regulated utility with a credit rating on its senior unsecured non-credit enhanced long-term debt of "A" or better as determined by Standard & Poor's.

11.7. Notices. All notices, demands and other communications hereunder shall be in writing and shall be delivered personally, mailed by certified mail, return receipt requested, postage prepaid, or sent by certified overnight courier (e.g., Federal Express) to the following addresses or to such other addresses as any party may specify by notice to the other party given pursuant hereto:

If to Pittsfield, to:

Pittsfield Generating Company, L.P.
c/o PE-Pittsfield, L.L.C.
1732 West Genesee Street
Syracuse, NY 13204
Attention: Donald W. Scholl

If to Cambridge, to:

Cambridge Electric Light Company
One NSTAR Way
Westwood, MA 02090
Attention: Ellen Angley, Vice President Energy Supply and Transmission

Any notice hereunder shall be deemed given when received by the intended recipient.

11.8. Counterparts. This Agreement and any amendment hereof may be executed in several counterparts and by each party on a separate counterpart, each of which when so executed and delivered shall be an original, but all of which together shall constitute one instrument. In proving this Agreement it shall not be necessary to produce or account for more than one such counterpart signed by the party against whom enforcement is sought.

IN WITNESS WHEREOF, and intending to be legally bound hereby, the parties hereto have caused this Agreement to be duly executed as an instrument under seal by their respective duly authorized officers as of the date and year first above written.

PITTSFIELD GENERATING COMPANY, L.P.

By: PE-Pittsfield, LLC, its General Partner

Jack E. Wolf
Vice-President

CAMBRIDGE ELECTRIC LIGHT COMPANY

By _____
Ellen K. Angley
Vice President Energy Supply and Transmission

Any notice hereunder shall be deemed given when received by the intended recipient.

11.8. Counterparts. This Agreement and any amendment hereof may be executed in several counterparts and by each party on a separate counterpart, each of which when so executed and delivered shall be an original, but all of which together shall constitute one instrument. In proving this Agreement it shall not be necessary to produce or account for more than one such counterpart signed by the party against whom enforcement is sought.

IN WITNESS WHEREOF, and intending to be legally bound hereby, the parties hereto have caused this Agreement to be duly executed as an instrument under seal by their respective duly authorized officers as of the date and year first above written.

PITTSFIELD GENERATING COMPANY, L.P.

By: PE-Pittsfield, LLC, its General Partner

_____
Jack E. Wolf
Vice-President

CAMBRIDGE ELECTRIC LIGHT COMPANY

By _____
Ellen K. Angley
Vice President Energy Supply and Transmission

APPENDIX B

TERMINATION AGREEMENT

This TERMINATION AGREEMENT (this "Agreement") is entered into on the 2nd day of June, 2004, by and between COMMONWEALTH ELECTRIC COMPANY, a Massachusetts corporation having its principal place of business at 800 Boylston Street, Boston, Massachusetts 02199 ("Commonwealth"), and PITTSFIELD GENERATING COMPANY, L.P. (f/k/a Altresco Pittsfield, L.P.) , a Delaware limited partnership with a principal place of business at 235 Merrill Road, Pittsfield, Massachusetts ("Pittsfield").

W I T N E S S E T H:

WHEREAS, Commonwealth and Pittsfield are parties to that certain Power Sale Agreement, dated February 20, 1992, as amended by an Amendment to Power Sale Agreement dated as of November 7, 1994 and a Second Amendment to Power Purchase Agreement dated as of November 21, 1996 (as so amended, the "Power Purchase Agreement"), pursuant to which Pittsfield sells to Commonwealth, and Commonwealth purchases from Pittsfield, a seventeen and two-tenths per cent (17.2%) entitlement to the capacity and associated electric energy produced by Pittsfield's facility situated in Pittsfield, Massachusetts (the "Facility"); and

WHEREAS, Pittsfield and Commonwealth desire to terminate the Power Purchase Agreement pursuant to, and in accordance with, the terms and provisions contained herein.

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the parties hereto hereby agree as follows:

1. **Definitions.** Capitalized terms used herein without definition shall have the respective meanings given to such terms in the Power Purchase Agreement. In addition, the term "Business Day" shall mean a day other than a Saturday, Sunday or any other day which is a legal holiday or a day on which banking institutions are authorized or required by law to close or be closed in Massachusetts.

2. **Effectiveness.**

2.1. The "Effective Date" shall be the third Business Day after the first date on which all of the following conditions have been satisfied: (i) approval by the Massachusetts Department of Telecommunications and Energy ("DTE"), in form and substance reasonably satisfactory to the parties, of (A) this Agreement, including but not limited to the termination of the Power Purchase Agreement pursuant to the terms hereof, and (B) the full recovery of the Termination Payments through Commonwealth's Transition Charge (as defined under G.L. c. 164, Section 1G), and either (x) the expiration of any appeal periods applicable to such DTE approval, or (y) if an appeal of such approval is filed within any such applicable appeal period, the issuance of a final ruling denying such appeal or resolving such appeal on terms acceptable to both parties (collectively, the "Commonwealth Approvals"); (ii) notice of termination (the "FERC

Notice") of the Power Purchase Agreement is provided by Pittsfield to the Federal Energy Regulatory Commission ("FERC") consistent with FERC's requirements therefore and such FERC Notice becomes effective; (iii) Commonwealth and Pittsfield shall have given (or been deemed to have given) notice that the Commonwealth Approvals are acceptable pursuant to Section 2.2; and (iv) Commonwealth and Pittsfield shall have given (or been deemed to have given) notice that the final order or other determination approving, disapproving or ruling in any way on the FERC Notice is acceptable pursuant to Section 2.3; provided, however, that notwithstanding satisfaction of the foregoing conditions, the Effective Date shall be no earlier than October 1, 2004. Notwithstanding the foregoing, this Agreement shall terminate and be of no further force or effect whatsoever (including, without limitation, the provisions of Sections 3, 4, and 5 hereof) as provided in Section 7.

2.2. No later than five (5) Business Days after the issuance by DTE or any appellate court or other judicial body with jurisdiction over the DTE, of any order or other determination approving, disapproving or ruling in any way on this Agreement, Commonwealth shall provide Pittsfield with: (i) written notice of such order or determination including a copy thereof; and (ii) certification of an authorized officer of Commonwealth as to whether such order or determination is reasonably acceptable to Commonwealth. No later than five (5) Business Days after receipt of such notice and documentation, Pittsfield shall provide Commonwealth with a certification of an authorized officer of Pittsfield as to whether such order or determination is reasonably acceptable to Pittsfield. Failure by either party to provide such written certification within five (5) Business Days of a written request by the other party shall constitute certification that such order or determination is reasonably acceptable to such party.

2.3 No later than five (5) Business Days after the issuance by FERC or any appellate court or other judicial body with jurisdiction over the FERC, of any order or other determination approving, disapproving or ruling in any way on the termination of the Power Purchase Agreement, Pittsfield shall provide Commonwealth with: (i) written notice of such order or determination including a copy thereof any; and (ii) certification of an authorized officer of Pittsfield as to whether such order or determination is reasonably acceptable to Pittsfield. No later than five (5) Business Days after receipt of such notice and documentation, Commonwealth shall provide Pittsfield with a certification of an authorized officer of Commonwealth as to whether such order or determination is reasonably acceptable to Commonwealth. Failure by either party to provide such written certification within five (5) Business Days of a written request by the other party shall constitute certification that such order or determination is reasonably acceptable to such party.

3. Termination of Agreements.

3.1. Agreement to Terminate. Pittsfield and Commonwealth hereby agree that, effective as of 12:00:01 am eastern time on the Effective Date, the Power Purchase Agreement shall be deemed terminated without any further action being required on the part of either Commonwealth or Pittsfield, provided that Pittsfield has received confirmation of the transfer of the initial Termination Payment to be made pursuant to Section 4 of this Agreement. Upon such termination: (i) Commonwealth shall have no obligation whatsoever under the Power Purchase Agreement, including, without limitation, any obligation to purchase or accept electric energy or capacity produced by the Facility, and (ii) Pittsfield shall have no obligation whatsoever under the Power Purchase Agreement, including, without limitation, any obligation to sell to Commonwealth any electric energy or capacity produced by the Facility. Notwithstanding the preceding sentence and said termination of the Power Purchase Agreement: (a) Commonwealth shall remain obligated to make payments to Pittsfield pursuant to the terms of the Power Purchase Agreement on account of any electric energy and capacity produced by the Facility and supplied to Commonwealth at any time up to the Effective Date ("PPA Payments"), to the extent that any such amounts remain unpaid on the Effective Date; and (b) Pittsfield shall remain obligated to make any PPA Refunds. "PPA Refunds" shall be any amounts owed by Pittsfield to Commonwealth pursuant to the terms of the Power Purchase Agreement on account of adjustments or reconciliations resulting from errors in measuring, or calculating charges for, energy or capacity delivered by Pittsfield to Commonwealth at any time up to the Effective Date that Commonwealth provides notice of no later than ninety (90) days after the Effective Date. Any disputes regarding PPA Payments and/or PPA Refunds shall be resolved pursuant to the terms of the Power Purchase Agreement. The parties agree to cooperate with each other in taking any and all actions that may be reasonably requested by the other in order to facilitate the approval of this Agreement by the DTE and, if this Agreement is approved by the DTE in for and substance acceptable to the parties, the termination of the Power Purchase Agreement.

3.2. Release of Liens. On the Effective Date, Commonwealth shall release and discharge any and all mortgages, security interests, letters of credit and/or other liens (collectively, "Liens") that it may have on or with respect to the Facility or Pittsfield, including without limitation: (a) the Agreement in Lieu of Second Mortgage dated as of March 20, 1992 among Commonwealth, Pittsfield and certain other parties; (b) the Declaration of Easements, Covenants and Restrictions made by Pittsfield and the owner participant under Pittsfield's lease financing dated March 20, 1992; and (c) the Accommodation Agreement dated as of March 20, 1992 among Pittsfield, Commonwealth and certain other parties. Commonwealth shall execute and deliver any and all documents and take any further actions that Pittsfield may reasonably request in order to effectively release and discharge all of such Liens.

4. Payments by Commonwealth.

4.1 Termination Payments. For and in consideration of Pittsfield's agreement to terminate the Power Purchase Agreement, Commonwealth shall pay, and hereby promises to pay, to the order of Pittsfield the following monthly payment amounts (collectively, the "Termination Payments", and individually, each monthly payment a "Termination Payment"); provided that the first Termination Payment shall be due on the Effective Date and shall be equal to (x) the monthly payment amount owed for the month in which the Effective Date occurs multiplied by (y) a fraction, the numerator of which is the number of days remaining in such month (including the Effective Date) and the denominator of which is the number of days in such month.

Calendar Year During Which Termination Payment is Owed	Termination Payment Amount
2004	$835,000
2005	$417,500
2006	$1,252,500
2007	$835,000
2008	$835,000

After the Effective Date, Commonwealth shall make Termination Payments on the first Business Day of each calendar month beginning with the month following the month in which the Effective Date occurs and continuing through and including December 1, 2008. Each Termination Payment shall be made by wire transfer to an account designated in writing from time to time by Pittsfield.

4.2 Unconditional Obligation. Commonwealth's obligations to make each Termination Payment when due under this Agreement are subject to the terms and conditions set forth in this Agreement and are otherwise absolute, unconditional and irrevocable and are not subject to cancellation, termination, modification, repudiation, excuse or substitution by Commonwealth. Commonwealth is not entitled to any abatement, reduction, offset, defense or counterclaim with respect to the obligations to make each Termination Payment when due under this Agreement for any reason whatsoever.

4.3 PPA Payments. Commonwealth shall pay Pittsfield for: (a) all energy delivered up to the Effective Date; and (b) any other charges owed by Commonwealth pursuant to the Power Purchase Agreement with respect to the month in which the Effective Date occurs, which charges shall be prorated based on the number of days in such month during which the Purchase Power Agreement was in effect.

5. Releases.

5.1. Releases by Commonwealth. Effective as of midnight on the Effective Date, Commonwealth, for itself, its successors and assigns, hereby releases and forever discharges Pittsfield, the general and limited partners of Pittsfield, all of the officers,

directors, employees and agents of Pittsfield and all of the partners, officers, directors, employees and agents of the general or limited partners of Pittsfield (collectively, for purposes of this Section 5.1, the "Pittsfield Released Parties") from any and all claims, demands, actions, causes of action, accounts, covenants, contracts, torts, agreements, obligations, debts, suits, judgments, executions, sums, damages, or liabilities whatsoever in law or equity, whether known or unknown to Commonwealth, which Commonwealth, its successors and assigns ever had, now have or may ever have for, upon or by reason of any matter, cause, circumstance or fact whatsoever existing at any time from the beginning of the world to and including the Effective Date, against any and all of the Pittsfield Released Parties related to or arising under the Power Purchase Agreement; provided, however, that Commonwealth does not hereby release Pittsfield from: (i) any of Pittsfield's obligations under this Agreement; or (ii) any of Pittsfield's obligations to pay PPA Refunds.

5.2. Release by Pittsfield. Effective as of midnight on the Effective Date, Pittsfield, for itself, its successors and assigns, hereby releases and forever discharges Commonwealth and its officers, directors, employees and agents (collectively, for purposes of this Section 5.2, the "Commonwealth Released Parties") from any and all claims; demands, actions, causes of action, accounts, covenants, contracts, torts, agreements, obligations, debts, suits, judgments, executions, sums, damages, or liabilities whatsoever in law or equity, whether known or unknown to Pittsfield, which Pittsfield, its successors and assigns ever had, now have or may ever have for, upon or by reason of any matter, cause, circumstance or fact whatsoever existing at any time from the beginning of the world to and including the Effective Date, against any and all of the Commonwealth Released Parties related to or arising under the Power Purchase Agreement; provided, however, that Pittsfield does not hereby release Commonwealth from: (i) any of Commonwealth's obligations under this Agreement; or (ii) any of Commonwealth's obligations to pay PPA Payments.

6. Consent of Regulatory Bodies.

6.1 Consent of the DTE. Commonwealth shall: (i) within thirty (30) days of the date of this Agreement file a copy of this Agreement with the DTE together with a request for approval of the same; (ii) exercise all commercially reasonable efforts to obtain an expedited review by the DTE of this Agreement and the termination of the Power Purchase Agreement pursuant hereto; and (iii) exercise all commercially reasonable efforts to secure the DTE's approval of this Agreement, the termination of the Power Purchase Agreement, and the full recovery of the Termination Payments through Commonwealth's Transition Charge. Commonwealth agrees to provide Pittsfield with a draft of the proposed request for approval of this Agreement to be filed with the DTE at least five (5) days prior to its submission to the DTE, to consider modifications to such request that are suggested by Pittsfield, and to generally consult with Pittsfield prior to filing such request; provided that the draft provided Commonwealth may exclude: (a) competitive, proprietary or confidential information relating to other power purchase agreements; and (b) information relating to the Power Purchase Agreement which is being submitted to the DTE on a confidential basis. Pittsfield hereby agrees to diligently

cooperate with, to not oppose or protest, and to use all commercially reasonable efforts to assist Commonwealth with respect to the Commonwealth Approvals, said cooperation and commercially reasonable efforts to include, without limitation: (i) providing any information or supporting documentation as may be reasonably required to establish to the satisfaction of the DTE that the payment to be made hereunder is reasonable and prudent; and (ii) making its employees or agents reasonably available for any appearance before the DTE that may be required by the DTE.

6.2 Notice to FERC. Pittsfield shall: (i) within thirty (30) days of the date of this Agreement, file the FERC Notice in accordance with FERC regulations and procedures; and (ii) exercise all commercially reasonable efforts to secure that FERC deems such notice effective as of the earliest date feasible. Pittsfield agrees to provide Commonwealth with a draft of the proposed FERC Notice at least five (5) days prior to its submission to the FERC, to consider modifications to such FERC Notice that are suggested by Commonwealth, and to generally consult with Commonwealth prior to filing such notice. Commonwealth hereby agrees to diligently cooperate with, to not oppose or protest, and to use all commercially reasonable efforts to assist Pittsfield with respect to the FERC Notice, said cooperation and commercially reasonable efforts to include, without limitation, providing any information or supporting documentation as may be reasonably required by Pittsfield.

7. Termination; Remedies.

7.1 Pittsfield may terminate this Agreement on written notice to Commonwealth if the Effective Date has not occurred by January 3, 2005.

7.2 Commonwealth may terminate this Agreement on written notice to Pittsfield if, despite Commonwealth's compliance with Section 6, the Effective Date has not occurred by January 3, 2005.

7.3 Upon any termination under Section 7.1 or 7.2: (i) this Agreement shall terminate and be of no further force or effect whatsoever (including, without limitation, the provisions of Sections 3, 4, and 5 hereof); and (ii) each of the Power Purchase Agreement, and the Liens shall continue in full force and effect and shall remain the valid and binding obligation of each party thereto enforceable against each such party in accordance with their terms.

7.4 Without limiting other remedies available to Pittsfield or Commonwealth, if Commonwealth fails to make any Termination Payment or other payments required pursuant to this Agreement, as and when such payments are due in accordance with the terms hereof interest shall accrue on any such unpaid amounts at an annual rate of interest equal to the prime rate of interest on commercial loans then in effect at Bank of America plus six hundred (600) basis points, compounded daily. In addition, to the extent any such amounts remain unpaid for a period of ten (10) Business Days following notice of such failure by Pittsfield, Commonwealth shall be obligated to post security in the form of a segregated cash collateral account or a letter of credit in form and substance and held

by an agent or issued by an issuer, as applicable, reasonably acceptable to Pittsfield, in an amount equal to two (2) Termination Payments (i.e., $1,670,000). Such security shall be available for drawing by Pittsfield in an amount or amounts equal to overdue sums (including interest thereon) owed by Commonwealth; provided that in the event Pittsfield makes a drawing of any such security as permitted hereunder, Commonwealth shall replenish the amount of such security to the value specified above. In addition, if Pittsfield incurs any costs (including but not limited to internal costs and attorneys' fees) in order to collect overdue amounts owed hereunder (other than PPA Payments) or to enforce its right to obtain security as provided herein, Commonwealth shall reimburse Pittsfield for any reasonable costs incurred in connection with such collection efforts no later than ten (10) days after submission by Pittsfield of any invoice accompanied by reasonable supporting documentation.

8. Facility Status. After the Effective Date, Pittsfield, at its sole discretion, may sell, modify, close, or utilize the Facility for sales to others.

9. Stay. As of the date of this Agreement, any and all notices of any breaches, events of default or disputes under the Power Purchase Agreement shall be stayed, without prejudice. The parties agree further not to submit any such notices unless and until this Agreement is terminated. Nothing contained herein shall prejudice either party's right to pursue any claim(s) arising after the date of this Agreement for PPA Payments or PPA Refunds, or any claim so stayed to the extent this Agreement is terminated.

10. Representations and Warranties.

10.1 Commonwealth's Representations and Warranties. Commonwealth represents and warrants to Pittsfield that:

(A) It has all requisite power and authority (including full corporate power and legal authority) to execute and deliver this Agreement, and subject to receipt of the Commonwealth Approvals, to perform its obligations hereunder;

(B) All necessary action has been taken to authorize the execution, delivery and performance by Commonwealth of this Agreement and this Agreement constitutes the valid, legal, and binding commitment of Commonwealth and is fully enforceable against Commonwealth in accordance with the terms hereof;

(C) Commonwealth's execution, delivery, and performance of this Agreement have been duly authorized by or are in accordance with its corporate charter, bylaws, and other organizational documents and constitutes Commonwealth's legal, valid, and binding obligation;

(D) The person executing this Agreement is duly authorized to do so by Commonwealth's governing body;

(E) There is no action, suit or proceeding, at law or in equity, nor is there any official investigation pending or, to the best of Commonwealth's knowledge, threatened against Commonwealth wherein an unfavorable decision, ruling or finding would adversely affect the performance by Commonwealth of its obligations hereunder or which, in any way, calls into question or may adversely and materially affect the validity or enforceability of this Agreement;

(F) Subject to Commonwealth's obtaining the Commonwealth Approvals and Pittsfield's proper filing of the FERC Notice, neither the execution or delivery of this Agreement nor performance by Commonwealth of the transactions contemplated hereby will: (1) conflict with or violate any provision of Commonwealth's corporate charter or bylaws; or (2) conflict with, violate or result in a breach of any duty under any applicable constitution, law, judgment, regulation, or order of any governmental authority;

(G) Except for the Commonwealth Approvals and FERC Notice, no approval, authorization, order or consent of, or declaration, registration or filing with any governmental authority is required for the valid execution, delivery and performance of this Agreement by Commonwealth; and

(H) Commonwealth's execution, delivery and performance of this Agreement will not result in a breach or violation of, or constitute a default under, any agreement, lease, or instrument to which it is a party or by which it is bound as of the date hereof.

10.2 Pittsfield's Representations and Warranties. Pittsfield represents and warrants to Commonwealth that:

(A) It has all requisite power and authority (including full corporate power and legal authority) to execute and deliver this Agreement, and, subject to the effectiveness of the FERC Notice, to perform its obligations hereunder;

(B) All necessary action has been taken to authorize the execution, delivery and performance by Pittsfield of this Agreement and this Agreement constitutes the valid, legal, and binding commitment of Pittsfield and is fully enforceable against Pittsfield in accordance with the terms hereof;

(C) Pittsfield's execution, delivery, and performance of this Agreement have been duly authorized by or are in accordance with its corporate charter, bylaws, and other organizational documents and constitutes Pittsfield's legal, valid, and binding obligation;

(D) The person executing this Agreement is duly authorized to do so by Pittsfield's governing body;

(E) There is no action, suit or proceeding, at law or in equity, nor is there any official investigation pending or, to the best of Pittsfield's knowledge, threatened against Pittsfield wherein an unfavorable decision, ruling or finding would adversely affect the performance by Pittsfield of its obligations hereunder or which, in any way, calls into question or may adversely and materially affect the validity or enforceability of this Agreement;

(F) Neither the execution or delivery of this Agreement nor performance by Pittsfield of the transactions contemplated hereby will: (1) conflict with or violate any provision of Pittsfield's corporate charter or bylaws; or (2) conflict with, violate or result in a breach of any duty under any applicable constitution, law, judgment, regulation, or order of any governmental authority;

(G) No approval, authorization, order or consent of, or declaration, registration or filing with any governmental authority is required for the valid execution, delivery and performance of this Agreement by Pittsfield, except for the filing of the FERC Notice; and

(H) Pittsfield's execution, delivery and performance of this Agreement will not result in a breach or violation of, or constitute a default under, any agreement, lease, or instrument to which it is a party or by which it is bound as of the date hereof.

11. Miscellaneous.

11.1. No Waiver. No failure on the part of any party to exercise, and no delay in exercising, any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any single or partial exercise by any party of any right, remedy or power hereunder preclude any other or future exercise of any other right, remedy or power.

11.2. Severability. In the event any provision of this Agreement that is not material shall for any reason be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not effect any other term or provision hereof.

11.3. Entire Agreement; Amendment. This Agreement contains the entire understanding of the parties, supersedes all prior agreements and understandings relating to the subject matter hereof, and shall not be amended, modified or terminated except by a written instrument hereafter signed by all of the parties hereto.

11.4. Sections and Section Headings. The headings of any of the sections and subsections are for reference only and shall not limit or control the meaning thereof.

11.5. Governing Law. The validity and construction of this Agreement shall be governed by the internal laws (and not the choice-of-law rules) of the Commonwealth of Massachusetts.

11.6 Binding Effect; Assignment. All terms of this Agreement shall be binding upon and inure to the benefit of and be enforceable by the respective successors and assigns of the parties hereto. Neither party shall have the right to assign this Agreement or any right, obligation or privilege hereunder without first obtaining the consent of the other party hereto; provided that: (i) Pittsfield shall have the right to assign its right to receive the Termination Payments, provided that any such assignee shall confirm in writing that it is taking such assignment subject to the terms of this Agreement; (ii) Pittsfield shall have the right to assign this Agreement at any time after the deadline for Commonwealth to claim any PPA Refunds shall have expired and either: (a) Commonwealth shall not have claimed any PPA Refunds, (b) Pittsfield shall have paid all PPA Refunds claimed by Commonwealth or determined to be owed to Commonwealth; or (c) Pittsfield shall have posted an irrevocable letter of credit in favor of Commonwealth, and in form and substance reasonably acceptable to Commonwealth, in the amount of any PPA Refunds claimed by Commonwealth; and (iii) Commonwealth shall have the right to assign this Agreement to a wholly-owned subsidiary of NSTAR that is a regulated utility with a credit rating on its senior unsecured non-credit enhanced long-term debt of "A" or better as determined by Standard & Poor's.

11.7. Notices. All notices, demands and other communications hereunder shall be in writing and shall be delivered personally, mailed by certified mail, return receipt requested, postage prepaid, or sent by certified overnight courier (e.g., Federal Express) to the following addresses or to such other addresses as any party may specify by notice to the other party given pursuant hereto:

If to Pittsfield, to:

Pittsfield Generating Company, L.P.
c/o PE-Pittsfield, L.L.C.
1732 West Genesee Street
Syracuse, NY 13204
Attention: Donald W. Scholl

If to Commonwealth, to:

Commonwealth Electric Company
One NSTAR Way
Westwood, MA 02090
Attention: Ellen Angley, Vice President Energy Supply and Transmission

Any notice hereunder shall be deemed given when received by the intended recipient.

11.8. Counterparts. This Agreement and any amendment hereof may be executed in several counterparts and by each party on a separate counterpart, each of which when so executed and delivered shall be an original, but all of which together shall constitute one instrument. In proving this Agreement it shall not be necessary to produce or account for more than one such counterpart signed by the party against whom enforcement is sought.

IN WITNESS WHEREOF, and intending to be legally bound hereby, the parties hereto have caused this Agreement to be duly executed as an instrument under seal by their respective duly authorized officers as of the date and year first above written.

PITTSFIELD GENERATING COMPANY, L.P.

By: PE-Pittsfield, LLC, its General Partner

_____
Jack E. Wolf
Vice-President

COMMONWEALTH ELECTRIC COMPANY

By _____
Ellen K. Angley
Vice President Energy Supply and Transmission

Commonwealth Electric Company
One NSTAR Way
Westwood, MA 02090
Attention: Ellen Angley, Vice President Energy Supply and Transmission

Any notice hereunder shall be deemed given when received by the intended recipient.

11.8. Counterparts. This Agreement and any amendment hereof may be executed in several counterparts and by each party on a separate counterpart, each of which when so executed and delivered shall be an original, but all of which together shall constitute one instrument. In proving this Agreement it shall not be necessary to produce or account for more than one such counterpart signed by the party against whom enforcement is sought.

IN WITNESS WHEREOF, and intending to be legally bound hereby, the parties hereto have caused this Agreement to be duly executed as an instrument under seal by their respective duly authorized officers as of the date and year first above written.

PITTSFIELD GENERATING COMPANY, L.P.

By: PE-Pittsfield, LLC, its General Partner

_____
Jack E. Wolf
Vice-President

COMMONWEALTH ELECTRIC COMPANY

By Ellen K Angley
Ellen K. Angley
Vice President Energy Supply and Transmission

COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Petition of Cambridge Electric Light Company and Commonwealth Electric Company for Approvals Relating to the Termination of Purchase Power Agreements with Pittsfield Generating Company, L.P.	)	D.T.E. 04-60

MOTION OF CAMBRIDGE ELECTRIC LIGHT COMPANY AND COMMONWEALTH ELECTRIC COMPANY FOR A PROTECTIVE ORDER

I. INTRODUCTION

On this date, Cambridge Electric Light Company ("Cambridge") and Commonwealth Electric Company ("Commonwealth," together, the "Companies") filed with the Department of Telecommunications and Energy (the "Department") a Petition (the "Petition") for Approvals Relating to Termination of Purchase Power Agreements (the "PPAs"). The Petition seeks approval by the Department, pursuant to G.L. c. 164, §§ 1A, 1G, 76, 94, and 94A, of: (a) the Termination Agreements between: (1) Cambridge and Pittsfield Generating Company, L.P. (formerly known as Altresco Pittsfield, L.P.) ("Pittsfield"); and (2) Commonwealth and Pittsfield (collectively, the "Pittsfield Termination Agreements"); and (b) approval of ratemaking treatment relating to the Pittsfield Termination Agreements.

As part of the Companies' filing, the Companies have submitted exhibits that, in part, include information regarding the Companies' projections of future energy prices and their forecasts of payments to be made pursuant to existing PPAs with Pittsfield and PPAs with other parties. Exhibit NSTAR-CAM-GOL-3, pages 13 through 15, Exhibit

NSTAR-CAM-GOL-4, pages 13 through 16, Exhibit NSTAR-CAM-GOL-5, pages 2 and 3, Exhibit NSTAR-CAM-GOL-6, pages 2 and 3, Exhibit NSTAR-CAM-GOL-7, pages 2 and 3, Exhibit NSTAR-CAM-GOL-8, pages 2 and 3, Exhibit NSTAR-COM-GOL-3, pages 13 through 15, Exhibit NSTAR-COM-GOL-4, pages 13 through 16, Exhibit NSTAR-COM-GOL-5, pages 2 and 3, Exhibit NSTAR-COM-GOL-6, pages 2 and 3, Exhibit NSTAR-COM-GOL-7, pages 2 and 3, Exhibit NSTAR-COM-GOL-8, pages 2 and 3, and Exhibit NSTAR-RBH-6, pages 2 through 5 (together, the "Confidential Documents"), contain proprietary, confidential and sensitive competitive information regarding: (1) the Companies' projections regarding the future market price of power; and (2) projections regarding the future costs of the Companies' existing PPAs. For the reasons set forth below, the Companies seek a protective order from the Department to prohibit public disclosure of this proprietary, confidential and sensitive competitive information.

II. LEGAL STANDARD

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

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

In interpreting the statute, the Department has held that:

> . . . [T]he burden on the company is to establish the need for protection of the information cited by the company. In determining the existence and

> extent of such need, the Department must consider the presumption in favor of disclosure and the specific reasons why disclosure of the disputed information benefits the public interest.

The Berkshire Gas Company et al., D.P.U. 93-187/188/189/190, at 16 (1994) as cited in Hearing Officers Ruling On the Motion of Boston Gas Company for Confidentiality, D.P.U. 96-50, at 4 (1996).

In practice, the Department has often exercised its authority to protect sensitive market information. For example, the Department has determined specifically that competitively sensitive information, such as price terms, are subject to protective status:

> The Department will continue to accord protective status when the proponent carries its burden of proof by indicating the manner in which the price term is competitively sensitive. Proponents generally will face a more difficult task of overcoming the statutory presumption against the disclosure of other terms, such as the identity of the customer.

Standard of Review for Electric Contracts, D.P.U. 96-39, at 2, Letter Order (August 30, 1996). See also Colonial Gas Company, D.P.U. 96-18, at 4 (1996) (the Department determined that price terms were protected in gas supply contracts and allowed Colonial Gas Company's request to protect pricing information including all "reservation fees or charges, demand charges, commodity charges and other pricing information").

Moreover, the Department has recognized that competitively sensitive terms in a competitive market should be protected and that such protection is desirable as a matter of public policy:

> The Department recognizes that the replacement gas purchases . . . are being made in a substantially competitive market with a wide field of potential suppliers. This competitive market should allow LDC's to obtain lower gas prices for the benefit of their ratepayers. Clearly the Department should ensure that its review process does not undermine the LDC's efforts to negotiate low cost flexible supply contracts for their systems. The Department also recognizes that a policy of affording contract confidentiality may add value to contracts and provide benefits to ultimate

consumers of gas, the LDC's ratepayers, and therefore may be desirable for policy reasons.

The Berkshire Gas Company et al., D.P.U 93-187/188/189/190, at 20 (1994).

III. INFORMATION REGARDING THE COMPANIES' ANALYSIS OF THE FUTURE ENERGY COSTS IS PROPRIETARY, CONFIDENTIAL AND SENSITIVE AND WARRANTS PROTECTION FROM PUBLIC DISCLOSURE

The Companies request confidential treatment of information relating to the Companies' projections of the market value of their existing PPAs and the projected costs to be incurred in future years for PPAs other than the Pittsfield PPAs. Each of the Confidential Documents contain the Companies' projections[1] of: (1) the annual dollars to be paid under each of their existing PPAs; (2) the Companies' projections relating to market prices of the electricity delivered under each of their existing PPAs; and (3) the projections of the annual above-market value of each of their existing PPAs. Most of the projections are derived from information in Exhibit NSTAR-RBH-6, which contains: (1) the Companies' projections of the market prices of energy (Pages 4-5); and (2) the Companies' detailed calculations of their projected costs of the existing Pittsfield PPAs, which are based on such market-price projections (Pages 2-3).

The Companies are seeking protected treatment for the Confidential Documents for several reasons. First, the market forecast data is considered proprietary by the company that produced it, and was provided to the Companies pursuant to a confidentiality agreement. More importantly, however, these projections must be protected from public disclosure because the Companies use this information to evaluate

[1] In some cases, the projections are not directly set forth, but can be computed with the data included in the page.

other PPA mitigation proposals. The Companies, as well as Boston Edison Company, have not yet completed the divestiture of all of their existing PPAs and are in active negotiations with other parties. If other parties had access to the details of the Companies' updated projections and assumptions regarding future energy prices and the value of their existing PPAs, the Companies' ability to negotiate the best deals possible on behalf of customers would be compromised. In fact, public release of the information in the Confidential Documents will disclose the very types of information that the Department has previously and consistently held to be confidential because the release of such information would "seriously undermine" the Companies' negotiating position and thus, result in customers not realizing the maximum amount of mitigation. Western Massachusetts Electric Company, D.T.E. 99-101, at 3 (2002), citing Boston Edison Company, D.T.E. 99-16 (1999); Western Massachusetts Electric Company, D.T.E. 99-56 (1999). See also Canal Electric Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E. 02-34 (Tr. A at 19 (June 12, 2002)) and Cambridge Electric Light Company, D.T.E. 01-94 (May 9, 2002 Approval by the Department of Amended Motion of Cambridge Electric Light Company for a Protective Order).

Accordingly, both the information and the Companies' strategic use of the information presented Confidential Documents should be protected from public disclosure through the issuance of a protective order because the information is proprietary, confidential and competitively sensitive. The disclosure of this sensitive information would undermine the Companies' ability to maximize mitigation efforts, which inures to the benefit of the Companies' customers. The Department has protected

similar information relating to analyses of the benefits of restructured or terminated PPAs submitted in previous proceedings. Therefore, the Companies request that the Department protect the market price and related analysis in the Confidential Documents from public disclosure, consistent with G.L. c. 25, § 5 and Department precedent.

IV. CONCLUSION

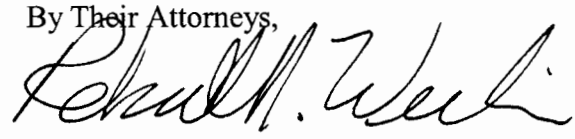
The Companies respectfully request that Confidential Documents be held confidential, not be placed in the public docket and be disclosed only to the Department. Parties to the case may request to review the exhibits, subject to the terms of a mutually agreed Non-Disclosure Agreement. This approach will allow the Department and parties to the proceeding to review the Companies' analysis of the Pittsfield Termination Agreements while ensuring that proprietary, confidential and sensitive market-related information will remain confidential.

WHEREFORE, for the reasons set forth herein, the Companies respectfully request that the Department allow the Companies' Motion for a Protective Order.

Respectfully submitted,

CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY

By Their Attorneys,



Robert N. Werlin, Esq.
John K. Habib, Esq.
Keegan, Werlin & Pabian, LLP
265 Franklin Street
Boston, Massachusetts 02110
(617) 951-1400 (telephone)
(617) 951-1354 (facsimile)

Date: June 29, 2004

CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a NSTAR ELECTRIC

Direct Testimony of Geoffrey O. Lubbock on Pittsfield Terminations

Exhibit NSTAR-GOL

D.T.E. 04-60

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Geoffrey O. Lubbock. My business address is One NSTAR Way, Westwood, Massachusetts, 02090.

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

A. I am employed by NSTAR Electric & Gas Corporation ("NSTAR E&G") as Vice President, Financial Strategic Planning & Policy. In my current position, I am responsible for a broad range of regulatory and financial planning responsibilities for Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge"), Commonwealth Electric Company ("Commonwealth") (collectively, "NSTAR Electric") and NSTAR Gas Company.

Q. Please describe your education and professional background.

A. I have a Bachelor and Master of Arts from Cambridge University and a Masters Degree in Business from the London Graduate School of Business. I joined Boston Edison Company ("Boston Edison") in 1988 as Manager of Revenue Requirements. In 1991, I became Manager of Revenue Requirements and Financial Planning. In 1993, I became Manager of Energy Research Planning and Forecasting. In 1995, I became Manager of Corporate Service Commitments and

in 1997, I became Director of Generation Divestiture. I assumed my current position in July 1998. Prior to Boston Edison, I was with the Cabot Corporation, Exxon Corporation and Citibank.

Q. Have you previously testified in any formal hearings before regulatory bodies?

A. Yes, on a number of occasions. I testified before the Department of Telecommunications and Energy (the "Department") to support Boston Edison's Restructuring Settlement Agreement in D.P.U./D.T.E. 96-23 and in connection with approval of the divestiture of Boston Edison's fossil generation assets in D.T.E. 97-113. I have also testified before the Department on behalf of Boston Edison in connection with the approval of its sale of the Pilgrim Nuclear Power Station to Entergy Nuclear Generation Company in D.T.E. 98-119.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Petition for Approval of the agreements to terminate the existing purchase power agreements ("PPAs") of Cambridge and Commonwealth with the Pittsfield Generating Company, L.P. (f/k/a Altresco Pittsfield, L.P.) ("Pittsfield"). In particular, I will describe the financial impact of the transaction, including the effect of the transaction on customer rates. In addition, I will demonstrate that the proposed transaction satisfies NSTAR Electric's obligation to mitigate its PPA-related stranded costs pursuant to the Electric Industry Restructuring Act, which is Chapter 164 of the

Acts of 1997 (the "Act") and Cambridge and Commonwealth's restructuring plan as approved in D.P.U./D.T.E. 97-111. To accomplish this, I will: (1) summarize the filing; (2) describe the divestiture requirements of the Act; (3) describe NSTAR Electric's efforts since the Act to divest its PPAs, including its recently completed competitive solicitation (the "2003 Auction"); and (4) support the request for approval of the termination agreements entered into between Cambridge and Commonwealth and Pittsfield dated June 2, 2004 (the "Pittsfield Termination Agreements") and associated ratemaking treatment of the related costs.

Q. Is NSTAR Electric submitting the testimony of other witnesses in this proceeding?

A. Yes. In addition to my own testimony, NSTAR Electric is sponsoring the testimony of Robert B. Hevert, President of Concentric Energy Advisors, Inc. ("CEA"), to provide details regarding the auction process and the auction results.

Q. How is the remainder of your testimony organized?

A. Section II outlines the divestiture provisions of the Act and the Department's Standard of Review for reviewing proposals to mitigate transition costs through contract modifications. Section III describes NSTAR Electric's efforts to divest its PPAs, including the 2003 Auction for the sale or transfer of NSTAR Electric's rights to 24 PPAs. Section IV describes the Pittsfield Termination Agreements, a demonstration that they will achieve significant mitigation of transition costs and

savings for customers, and the ratemaking treatment requested for the costs to be incurred under the Pittsfield Termination Agreements.

Q. Please describe the exhibits attached to your testimony.

A.

NSTAR-GOL-1	A single-page document that lists the PPAs that were included in the 2003 Auction.
NSTAR-CAM-GOL-1	A copy of the existing PPA (including amendments) between Cambridge and Pittsfield (the Pittsfield Termination Agreement for Cambridge is attached to the Petition as Appendix A).
NSTAR-CAM-GOL-2	A single-page document summarizing the total Cambridge customer savings produced by the Pittsfield Termination Agreements.
NSTAR-CAM-GOL-3	A multi-page document that details the forecasted Cambridge Transition Charges in the absence of the Pittsfield Termination Agreements.
NSTAR-CAM-GOL-4	A multi-page document that details the forecasted Cambridge Transition Charges after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.
NSTAR-CAM-GOL-5	A multi-page document that details the forecasted Cambridge Standard Offer Service revenues and costs for 2004 in the absence of the Pittsfield Termination Agreements.
NSTAR-CAM-GOL-6	A multi-page document that details the forecasted Cambridge Standard Offer Service revenues and costs for 2004 after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.
NSTAR-CAM-GOL-7	A multi-page document that details the forecasted Cambridge Standard Offer Service revenues and

costs for 2005 in the absence of the Pittsfield Termination Agreements.

NSTAR-CAM-GOL-8 A multi-page document that details the forecasted Cambridge Standard Offer Service revenues and costs for 2005 after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.

NSTAR-COM-GOL-1 A copy of the existing PPA (including amendments) between Commonwealth and Pittsfield (the Pittsfield Termination Agreement for Commonwealth is attached to the Petition as Appendix B).

NSTAR-COM-GOL-2 A single-page document summarizing the total Commonwealth customer savings produced by the Pittsfield Termination Agreements.

NSTAR-COM-GOL-3 A multi-page document that details the forecasted Commonwealth Transition Charges in the absence of the Pittsfield Termination Agreements.

NSTAR-COM-GOL-4 A multi-page document that details the forecasted Commonwealth Transition Charges after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.

NSTAR-COM-GOL-5 A multi-page document that details the forecasted Commonwealth Standard Offer Service revenues and costs for 2004 in the absence of the Pittsfield Termination Agreements.

NSTAR-COM-GOL-6 A multi-page document that details the forecasted Commonwealth Standard Offer Service revenues and costs for 2004 after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.

NSTAR-COM-GOL-7 A multi-page document that details the forecasted Commonwealth Standard Offer Service revenues

	and costs for 2005 in the absence of the Pittsfield Termination Agreements.
NSTAR-COM-GOL-8	A multi-page document that details the forecasted Commonwealth Standard Offer Service revenues and costs for 2005 after approval of the Pittsfield Termination Agreements and associated ratemaking treatment.

II. DIVESTITURE REQUIREMENTS

Q. Please describe the divestiture requirements of the Act for PPA buyouts and renegotiations.

A. The Act, as codified in G.L. c. 164, § 1 et seq., requires electric companies to seek to mitigate transition costs, including, as one mitigation method, the renegotiation of above-market power purchase contracts. G.L. c. 164, § 1G(d)(1) and (2). The Act further provides that, if a contract renegotiation, buy-out or buy-down is likely to achieve savings to customers and is otherwise in the public interest, the Department is authorized to approve the recovery of the costs associated with the contract restructuring. G.L. c. 164, § 1G(b)(1)(iv).

Q. Please describe how NSTAR Electric's Restructuring Settlement and Restructuring Plan address PPA buyouts or renegotiations.

A. Consistent with the Act, Boston Edison's Restructuring Settlement Agreement (the "Settlement Agreement"), approved by the Department in Boston Edison Company, D.P.U./D.T.E. 96-23, requires Boston Edison to mitigate its transition costs by "endeavor[ing] to sell, assign or otherwise dispose of its purchased power contracts on terms that will assign ongoing contract payments to a

nonaffiliated third party" (Settlement Agreement at §V.C.3.(a)). The Department found that the Settlement Agreement's provisions regarding mitigation were consistent with or substantially complied with the Act.

Also consistent with the Act, Cambridge's and Commonwealth's Electric Restructuring Plan (the "Restructuring Plan"), approved by the Department in Cambridge Electric Light Company/Canal Electric Company/Commonwealth Electric Company, D.P.U./D.T.E. 97-111, requires that Commonwealth undertake all reasonable steps to mitigate its transition costs and encourages the company to divest its non-nuclear generating assets. The Department has previously found that Commonwealth is committed to full mitigation of its transition costs, "principally by auctioning off…PPAs and generating plants" in compliance with the Act. D.P.U./D.T.E. 97-111, at 64. In this case, NSTAR Electric has presented the results of its 2003 Auction, and is requesting that the Department review the results of the auction process to ensure its compliance with the Act and applicable precedent in Massachusetts.

III. NSTAR ELECTRIC'S DIVESTITURE EFFORTS

Q. Please explain NSTAR Electric's efforts to divest its PPAs.

A. Boston Edison, Commonwealth and Cambridge have attempted to divest or renegotiate their respective PPAs since the enactment of the Act. Boston Edison discussed its mitigation efforts in three mitigation reports filed with the

Department (see Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, D.T.E. 00-70 (Mitigation Report of NSTAR Electric (January 19, 2001)); Department Investigation of Power Purchase Agreement Mitigation, D.T.E. 99-62 (August 24, 1999 Mitigation Report of Boston Edison Company); Department Investigation of Power Purchase Agreement Mitigation, D.T.E. 98-62 (July 30, 1998 Mitigation Report of Boston Edison Company)). In addition, Boston Edison submitted a PPA Divestiture Plan to the Department in June 1998, which provided for a combination of continued bilateral negotiations with the PPA sellers and an auction process to assign the rights to the PPA entitlements to be conducted in 1999.

Cambridge and Commonwealth's mitigation efforts were included in D.T.E. 00-70 (Mitigation Report of NSTAR Electric), referenced above, and also mitigation reports filed in D.T.E. 99-62 (on August 23, 1999) and in D.T.E. 98-62 (on July 31, 1998). Cambridge and Commonwealth, with the assistance of the Investment Firm Goldman Sachs, attempted to divest their entitlements through a separate entitlement auction held with their 1998 auction to divest generation assets. Neither of these auctions resulted in the transfer to third parties of the rights and obligations under the PPAs since the bids would not provide mitigation benefits to customers. However, NSTAR Electric has successfully bought out, bought down or otherwise renegotiated contractual obligations with individual

suppliers in a way that has provided mitigation of transition costs for customers as enumerated below.

Q. Please describe NSTAR Electric's 1999 Joint Auction of PPAs.

A. After the 1999 merger that created NSTAR, NSTAR Electric, with the assistance of Navigant Consulting, initiated a joint auction that included all of their remaining power contracts, as well as the supply of its Standard Offer load. The joint auction commenced in September 1999. The solicitation process included obtaining competitive bids for NSTAR Electric's interests in 29 separate PPAs totaling approximately 2,000 MW of capacity and associated energy. NSTAR Electric anticipated that it either would directly assign the PPAs to the winning bidder(s) or, where contracts were not readily assignable, enter into a back-to-back arrangement, thus effectively transferring all rights and obligations under the PPAs to the winning bidder(s) for the remaining term of the PPAs.

In parallel with the PPA auction, NSTAR Electric solicited offers for power necessary to meet certain of its Standard Offer Service obligation to retail customers. Although the PPA and Standard Offer Service load competitive bidding processes were conducted simultaneously, they were not contingent upon one another. To optimize the flexibility of the offering, NSTAR Electric solicited bids for: (1) all PPAs, any individual PPA, or any combination of PPAs; and/or

(2) all Standard Offer Service load or increments of Standard Offer Service load. The intent of this design was to maximize the value of the solicitation process.

The financial evaluation of the preliminary bids did not yield evidence of any mitigation for NSTAR Electric's customers. Analysis showed that most bidders required a significant premium over the estimated cost of the PPAs. Ultimately, NSTAR Electric determined that it would not be in the best interests of its customers to enter into a transaction as a result of the solicitation process.

Q. Prior to the 2003 Auction, was NSTAR Electric successful in buying out of or renegotiating individual PPAs?

A. Yes. NSTAR Electric has successfully renegotiated several PPAs with individual suppliers, thereby achieving significant mitigation of transition costs and savings for customers. The following PPAs have been renegotiated or bought-out since the passage of the Act:

- MBTA PPAs (amendments by Boston Edison);
- Plymouth Rock Energy Associates, L.P. (settlement of issues by Commonwealth);
- Pilgrim Nuclear Power Plant PPA (renegotiation by Commonwealth)
- L'Energia, Limited Partnership PPA (buy-out by Boston Edison);
- Lowell Cogeneration Company Limited Partnership PPA (buy-out by Commonwealth); and
- Southern PPA (renegotiation by Boston Edison, Cambridge and Commonwealth).

These mitigation efforts were detailed in the Mitigation Report of NSTAR Electric, January 19, 2001, at 32-42. In addition, since the date of that report NSTAR Electric has successfully completed the following PPA restructurings:

- Vermont Yankee PPA (Cambridge sale of plant and restructuring of power contract); and
- Seabrook Nuclear Power Station PPA (Canal Electric Company sale of plant and Cambridge and Commonwealth termination of power contract).

Q. Please describe NSTAR Electric's objective and scope of the 2003 Auction.

A. As described by Mr. Hevert, NSTAR Electric and CEA established a process that was equitable and structured to maximize the reduction in the above-market cost of the PPAs through a competitive auction that ensured the complete, uninhibited, non-discriminatory access to all data and information by any and all interested parties seeking to participate. The scope of the auction included NSTAR Electric's full portfolio of PPAs, as listed in Exhibit NSTAR-GOL-1.

Q. Do the Pittsfield Termination Agreements represent the only successfully renegotiated PPA from the 2003 Auction?

A. No. As a result of the 2003 Auction, NSTAR Electric has finalized or is close to finalizing new agreements relating to several of NSTAR Electric's remaining PPAs that, if approved by the Department, will result in NSTAR Electric having mitigated the vast majority (in terms of both amount electric energy purchases and above-market costs) of PPAs that will continue to be in effect after March 1,

2005. NSTAR Electric intends to seek Department approval of any such contracts in separate filings.

IV. THE PITTSFIELD TERMINATION AGREEMENTS

Q. Please describe in general terms the key provisions of the Pittsfield Termination Agreements.

A. The Pittsfield Termination Agreements were negotiated by NSTAR Electric and Pittsfield as a result of the 2003 Auction. As described in the testimony of Mr. Hevert, Cambridge and Commonwealth each currently has a PPA to purchase power from the Pittsfield generating facility located in Pittsfield, MA. The Pittsfield unit is a gas-fired, combined-cycle cogeneration facility consisting of three gas turbine/generators combined with three heat recovery steam generators driving a fourth generator. The plant has a current summer capacity rating of 141 MW, and a winter capacity rating of 173 MW. NSTAR Electric's two PPAs require Cambridge and Commonwealth to pay for delivered energy and capacity for 17.2 percent of the output of the plant through December 31, 2011. The pricing provisions of the existing PPAs include a capacity charge indexed to inflation, and an energy charge based on fuel price escalators. In addition, the PPA with Cambridge includes a separate transmission charge.

The Pittsfield Termination Agreements extinguish all obligations for Cambridge and Commonwealth to purchase power under the PPAs. In return, Cambridge and Commonwealth are together required to pay Pittsfield $1.67 million per month

from the Pittsfield Termination Agreements' Effective Date (currently expected to be October 1, 2004) through December 1, 2008. The Effective Date is defined in the Pittsfield Termination Agreements as three days after all of the preconditions, including regulatory approvals, have been met.

Q. What savings are derived from the Pittsfield Termination Agreements?

A. Compared to the existing PPAs, the Pittsfield Termination Agreements will result in approximately $6 million of savings to customers, on a net present value ("NPV") basis. The savings are determined by comparing the forecast Transition Charges to be paid by customers if the PPAs were to remain in effect with the Transition Charges to be paid by customers under the Pittsfield Termination Agreements. Summaries of the comparison, the annual savings and the NPV savings calculation are shown on Exhibit NSTAR-CAM-GOL-2 and Exhibit NSTAR-COM-GOL-2.

Q. If the above-market costs of the PPAs are recovered through the Transition Charge, why have you included exhibits relating to the revenues and costs associated with Standard Offer Service?

A. The electricity purchased through the PPAs is used to supply a portion of Cambridge's and Commonwealth's obligation to provide its customers with Standard Offer Service. Thus, the imputed costs of the output of all PPAs used for Standard Offer Service, the so-called "transfer price," is used to compute the above-market costs of PPAs. The transfer price is affected by the termination of

the existing Pittsfield PPAs because the reduced purchases will change the costs incurred to provide Standard Offer Service. By including in the analysis of customer savings a forecast of the changes in the transfer prices for Standard Offer Service, and its resulting impact on Transition Costs, all impacts on customers of the Pittsfield Termination Agreements are properly considered.

Q. If the Existing PPAs were to remain in effect, how would customers pay the forecast Transition Charges?

A. Each year Cambridge and Commonwealth file with the Department their latest forecast of Transition Costs to set the rates for the succeeding year. These were last filed in D.T.E. 03-118, which was updated on March 1, 2004. Exhibit CAM-JFL-3 (supp) and Exhibit COM-JFL-3 (supp) in D.T.E. 03-118 are the most recent submissions to the Department of the annual Transition Charge as filed in that update. Exhibit NSTAR-CAM-GOL-3 and Exhibit NSTAR-COM-GOL-3 in this filing contain updated forecasts for Transition Costs based on actual results through May 2004 and CEA's purchased power forecasts thereafter. These two exhibits will provide the base case or status quo Transition Charge forecasts against which the changes resulting from the Pittsfield Termination Agreements are measured.

Q. Have you also updated the exhibits for Standard Offer Service?

A. Yes. Each year when Cambridge and Commonwealth file their Transition Costs reconciliation, they also file their forecast of costs of providing Standard Offer

Service for the subsequent year to set the Standard Offer rates for that year. These were also updated on March 1, 2004. Exhibit CAM-JFL-6 (supp) and Exhibit COM-JFL-6 (supp) in D.T.E. 03-118 are the most recent Standard Offer Service submissions to the Department. These two computations of 2004 standard offer charges have been further updated in Exhibit NSTAR-CAM-GOL-5 and Exhibit NSTAR-COM-GOL-5 in this filing for actual results through May 2004 and CEA's purchased power forecasts thereafter. Since Standard Offer Service extends through the end of February 2005, Exhibit NSTAR-CAM-GOL-7 and Exhibit NSTAR-COM-GOL-7 have been prepared in this filing to show the forecast for Standard Offer Service for January and February 2005. These exhibits will provide the base case or status quo against which the changes resulting from the Pittsfield Termination Agreements are measured.

Q. How are the Transition Charges to be paid by customers under the Pittsfield Termination Agreements computed?

A. Exhibit NSTAR-CAM-GOL-4 and Exhibit NSTAR-COM-GOL-4 are in the same format as Exhibit NSTAR-CAM-GOL-3 and Exhibit NSTAR-COM-GOL-3, and compute Transition Charges with the costs incurred under the Pittsfield Termination Agreements instead of the Existing PPAs (pages 13 through 15). These exhibits also include the effect on the mitigation incentive (page 16). The exhibits do not yet include consulting and legal costs incurred by NSTAR Electric for to conduct the 2003 Auction. Because the consulting and legal costs will not

be known with precision until after the approval process is complete, these items will be reconciled to actual costs in future transition cost reconciliation filings. This reconciliation may include allocations to other contracts as they are approved which may results in the transfer of costs between the various NSTAR Electric companies. We would plan to allocate the costs based on the savings by contract.

Q. How are the impacts of Standard Offer Service under the Pittsfield Termination Agreements computed?

A. Exhibit NSTAR-CAM-GOL-6, Exhibit NSTAR-CAM-GOL-8, Exhibit NSTAR-COM-GOL-6 and Exhibit NSTAR-COM-GOL-8 are in the same format as Exhibit NSTAR-CAM-GOL-5, Exhibit NSTAR-CAM-GOL-7, Exhibit NSTAR-COM-GOL-5 and Exhibit NSTAR-COM-GOL-7. They compute the new transfer prices with the changes in supply cost incurred under the Pittsfield Termination Agreements instead of the existing PPAs. A third-party supplier serves the Standard Offer supply for the remainder of 2004 and when the Pittsfield contract is terminated, the Company needs to replace the missing power for the supplier. The impact of purchasing replacement power is shown on page 4, line 4 of Exhibit NSTAR-CAM-GOL-6 and Exhibit NSTAR-COM-GOL-6 and because under the contract, the replacement power quantity is different from the forecast Pittsfield generation, there is a slight change to the Short Term SO on line 3. These changes flow to the transfer price of NUG purchases shown on page 1, line 7. These are the transfer prices that set the market price of the PPAs in column E

of page 14 of Exhibit NSTAR-CAM-GOL-4 and Exhibit NSTAR-COM-GOL-4. These costs flow forward to the calculation of Transition Charges on page 1 of Exhibit NSTAR-CAM-GOL-4 and Exhibit NSTAR-COM-GOL-4 to determine the transition costs to be paid by customers after the Pittsfield Termination Agreements take effect. The costs after the termination are compared to the costs prior to the termination to arrive at the customer savings.

Q. Please explain the terms under which power is replaced under the existing Standard Offer Supply Source contract as a result of the Pittsfield buyout.

A. The contract extends through year end 2004 and for this period, the replacement must be comparable so that "the quantity of replacement Energy delivered to Supplier at the PPA delivery points (i) with respect to peak hours, is equal to 90% of the corresponding historical monthly average output under such PPA during Peak Hours distributed ratably over Peak Hours, and (ii) with respect to Off-Peak Hours, is equal to 100% of the corresponding historical monthly average output during Off-Peak Hours distributed ratably over Off-Peak hours. For purposes of the foregoing, the historical monthly average shall be determined by averaging the quantity of Energy delivered under such PPA (adjusted for the current NSTAR Electric ownership/share entitlement percentage, if necessary) during the five year period that ended sixty (60) days prior to the PPA Restructuring date". In the case of Pittsfield the historical output has significantly exceeded the more recent

output, with the result that the replacement kilowatt-hours significantly exceed the replaced forecast kilowatt-hours.

Q. Please explain why there is a different payment stream for Cambridge and Commonwealth in 2005 and 2006.

A. The Companies determined that some 2005 state tax benefits would be lost if the payments were evenly distributed between Cambridge and Commonwealth for 2005 and 2006. By changing the timing of the payments between Cambridge and Commonwealth in 2005 and 2006, the loss of state tax benefits could be minimized. Please note that in total the payment to Pittsfield is unchanged.

Q. Is Department approval required as a condition of the Pittsfield Termination Agreements?

A. Yes. Cambridge and Commonwealth must receive a final order from the Department approving the termination of the existing PPAs in accordance with the Pittsfield Termination Agreements and approving the full recovery of payments made pursuant under the Pittsfield Termination Agreements through the Transition Charge. If Department approval is not received, the existing contracts will remain unchanged and the Companies will continue to be obligated to purchase power from the unit on the existing terms.

Q. What is the proposed ratemaking treatment that is being requested in this case?

A. NSTAR Electric requests only that, like the over-market costs paid under the existing Pittsfield PPAs, the costs incurred under the Pittsfield Termination

Agreements continue to be recovered in the Transition Charges of Cambridge and Commonwealth as set forth in Exhibit NSTAR-CAM-GOL-4 and Exhibit NSTAR-COM-GOL-4, respectively. Of course, the payments made and Transition Charge revenues will continue to be reconciled to actual amounts as part of NSTAR Electric's annual reconciliation process in accordance with the terms of the approved Restructuring Plan.

Q. When is Department approval of the Pittsfield Termination Agreements requested?

A. The Pittsfield Termination Agreements anticipate an Effective Date of October 1, 2004. The Effective Date occurs three days after the expiration of the appeal period of a final Department order approving the Pittsfield Termination Agreements and requested ratemaking treatment. See Section 2.1 of Pittsfield Termination Agreements. Accordingly, NSTAR Electric requests Department action by September 7, 2004. Although the Pittsfield Termination Agreements may not be terminated by either party until January 3, 2005, delay of the Effective Date beyond October 1, 2004, will increase Transition Charges paid by customers.

Q. Why do you believe that the Department should approve the Pittsfield Termination Agreements?

A. The Pittsfield Termination Agreements should be approved by the Department because, consistent with the Act's requirements regarding the buyout of PPAs, the

Pittsfield Termination Agreements are both: (1) likely to achieve savings to customers; and (2) are otherwise in the public interest. Given the estimated savings of approximately $6 million on an NPV basis relating to the Pittsfield Termination Agreements and the fact that the savings will be passed on to customers, customers would realize a significant level of savings. Moreover, the buyout of PPAs is consistent with the Act and Cambridge and Commonwealth's Department-approved Restructuring Plan and therefore, approval of the Pittsfield Termination Agreements is in the public interest. Accordingly, the Pittsfield Termination Agreements are reasonable and consistent with the Department's standard of review for buyout agreements. Therefore, the Department should review and approve the Pittsfield Termination Agreements expeditiously so that the customers of Cambridge and Commonwealth may realize the significant amount of savings relating to the Pittsfield Termination Agreements.

Q. Does this conclude your testimony?

A. Yes.

Exhibit NSTAR-GOL-1

Unit & Contract	Capacity (MW)		Location	Expir.	Fuel	Technology
	Summer	**Winter**				
Altresco – Pittsfield (Cambridge)	24.3	29.8	Pittsfield, MA	2011	Gas	Combined cycle cogen
Altresco – Pittsfield (Commonwealth)	24.3	29.8	Pittsfield, MA	2011	Gas	Combined cycle cogen
Boott Hydro (Commonwealth)	20.0	20.0	Lowell, MA	2023	Water	Hydro
Chicopee Hydro (Commonwealth)	2.2	2.2	Chicopee, MA	2013	Water	Hydro
Collins Hydro (Commonwealth)	1.3	1.3	N. Wilbraham, MA	2013	Water	Hydro
Dartmouth Power (Commonwealth)	61.80	67.9	Dartmouth, MA	2017	Gas	Combined cycle with supplemental firing
MASSPOWER (Boston Edison)	100.0	117.0	Indian Orchard, MA	2013	Gas	Combined cycle cogen
MASSPOWER 1 (Commonwealth)	25.7	30.0	Indian Orchard, MA	2008	Gas	Combined cycle cogen
MASSPOWER 2 (Commonwealth)	25.7	30.0	Indian Orchard, MA	2013	Gas	Combined cycle cogen
MBTA 1 (Boston Edison)	25.0	33.4	South Boston, MA	2005	Jet Fuel	Combustion Turbine
MBTA 2 (Boston Edison)	25.0	34.7	South Boston, MA	2019	Jet Fuel	Combustion Turbine
NEA A (Boston Edison)	123.5	153.0	Bellingham, MA	2016	Gas	Combined cycle cogen
NEA B (Boston Edison)	68.0	92.0	Bellingham, MA	2011	Gas	Combined cycle cogen
NEA 1(Commonwealth)	22.9	28.3	Bellingham, MA	2016	Gas	Combined cycle cogen
NEA 2 (Commonwealth)	19.2	23.8	Bellingham, MA	2016	Gas	Combined cycle cogen
Ocean State 1 (Boston Edison)	63.7	74.5	Burrillville, RI	2010	Gas	Combined cycle cogen
Ocean State 2 (Boston Edison)	62.0	72.9	Burrillville, RI	2011	Gas	Combined cycle cogen
Pilgrim (Boston Edison)	230.8	230.8	Plymouth, MA	2004	Nuclear	Nuclear
Pilgrim Municipals (Boston Edison)	24.4	24.4	Plymouth, MA	2004	Nuclear	Nuclear
Pilgrim (Commonwealth)	36.0	36.0	Plymouth, MA	2004	Nuclear	Nuclear
Pioneer Hydro (Commonwealth)	1.30	1.30	Ware, MA	2014	Water	Hydro
SEMASS (Commonwealth)	46.2	50.7	Rochester, MA	2015	Refuse	Steam boiler
SEMASS Expansion (Commonwealth)	20.9	24.3	Rochester, MA	2015	Refuse	Steam boiler
Vermont Yankee (Cambridge)	12.7	13.2	Vernon, VT	2012	Nuclear	Nuclear
Total MW	**1066.7**	**1221.1**				

EXHIBIT NSTAR-CAM-GOL-1

POWER SALE AGREEMENT

by and between

ALTRESCO PITTSFIELD, L.P.

and

CAMBRIDGE ELECTRIC LIGHT COMPANY

for a 17.2 percent entitlement
to the electric capacity and related energy
to be produced by
an approximately 160 megawatt gas-fired
cogeneration facility
located in Pittsfield, Massachusetts

[1A-71]

POWER SALE AGREEMENT

Agreement entered into this 20th day of February, 1992 by and between Cambridge Electric Light Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Altresco Pittsfield, L.P., a Delaware limited partnership duly authorized to do business in the Commonwealth of Massachusetts with its principal place of business at 600 South Cherry Street, Denver, Colorado (the "Seller").

The Seller operates an electric cogeneration facility, consisting of a gas-fired, combined cycle generation plant, together with housings and other integral equipment, and which is capable of generating approximately one-hundred sixty megawatts (160 MW) of electricity (the "Unit"). The Unit is located in Pittsfield, Massachusetts, at a site owned by General Electric Company (the "Lessor"), more particularly described in Appendix A attached hereto (the "Site"). The Seller has leased the Site from the Lessor for the full anticipated term of this Agreement. The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of a percentage of the electric capacity and related energy produced by the Unit, pursuant to the terms and conditions set forth in this Agreement.

Therefore, the parties, each in consideration of the agreements of the other, hereby agree as follows.

ARTICLE 1. Definitions.

When used with initial capitalizations, whether in the singular or in the plural, the following terms shall have the following meanings.

Actual In-Service Date shall be the later to occur of (i) September 1, 1993, or (ii) the date on which all transmission services necessary to deliver power hereunder are secured pursuant to Article 3.2 of this Agreement.

Billing Period shall mean any calendar month in which the Unit produces electricity pursuant to this Agreement and for which the Company is obligated to pay for such electricity produced for such month pursuant to this Agreement.

Capability shall mean the maximum dependable load carrying ability of the Unit during the applicable Seasonal Period (exclusive of capacity required for Unit use). Capability shall be determined by the NEPOOL Operations Committee in accordance with NEPOOL Criteria, Rules and Standards ("CRS") Nos. 4 and 26. In the event that CRS No. 4 or No. 26 ceases to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that would have the same effect as these CRS's in determining Capability.

Capability Audit shall mean a test of the Unit's Capability conducted periodically pursuant to the provisions of Section 8.13 of the NEPOOL Agreement or any properly issued replacement therefor created from time to time during the term of this Agreement.

Capacity Deficiency shall mean the amount, if any, by which the Company's Capacity Entitlement is less than twenty-five thousand kilowatts (25,000 kW) during the Summer Period and is less than twenty-seven thousand kilowatts (27,000 kW) during the Winter Period.

Company's Capacity Entitlement shall be equal to the product of (i) the Company's Entitlement, multiplied by (ii) the audited Capability during the applicable Seasonal Period; provided, however, that the Company's Capacity Entitlement shall not exceed the maximum amount of electric capacity that the Company is obligated to purchase in accordance with Article 2.1 of this Agreement.

Company's Entitlement shall mean 17.2 percent (17.2%), which is the ratio of the Summer Period Contract Capacity to the Summer Period Design Capacity.

Company's Solicitation shall mean the Second Request for Proposals for Qualifying Facility Generation, dated 1990, issued by the Company pursuant to the regulations of the MDPU as set forth at 220 C.M.R. 8.00.

Contract Capacity shall mean twenty-five thousand kilowatts (25,000 kW) during the Summer Period and twenty-eight thousand, four-hundred kilowatts (28,400 kW) during the Winter Period.

Delivered Energy shall mean, for each Billing Period, the product of (i) 0.99 and (ii) the kilowatthours metered during the Billing Period pursuant to Article 7 of this Agreement minus the Non-Pool transmission losses (in kilowatthours) as may be applicable to the wheeling agreement pursuant to which the Company's Entitlement to electricity produced by the Unit will be transmitted to the Delivery Point.

Delivery Point shall mean the point at which the Company's transmission or distribution system connects with the transmission or distribution system of Boston Edison Company, which is the adjacent utility that is wheeling the electricity produced by the Seller to be purchased by the Company.

Design Capacity shall mean one-hundred, forty-five megawatts (145 MW) during the Summer Period and one-hundred, sixty-five megawatts (165 MW) during the Winter Period.

Economic Dispatch shall mean the operation of the Unit in accordance with such procedures as may be established by NEPOOL from time to time to foster the objective of satisfying the energy requirements of the participants of NEPOOL at the lowest practicable cost.

FERC shall mean the Federal Energy Regulatory Commission.

Good Utility Practice shall mean the practice, methods, and acts (including but not limited to the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy, and expediency. With respect to the Unit, Good Utility Practice includes but is not limited to taking reasonable steps to ensure the following.

(1) That adequate materials, resources, and supplies, including fuel, are available to meet the Unit's needs;

(2) That sufficient operating personnel are available and are adequately experienced, trained, and licensed as necessary to operate the Unit properly and efficiently, and who are capable of responding to emergency conditions whether caused by events on or off the Site;

(3) That preventative, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(4) That appropriate monitoring and testing are performed to ensure that equipment is functioning as designed;

(5) That equipment is not operated recklessly, or in a manner that is unsafe to workers, the general public, or the environment, or without regard to defined limitations such as steam pressure, temperature, and moisture content, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, frequency, rotational speed, polarity, synchronization, or control system limits;

(6) That equipment will function properly under both normal and emergency conditions; and

(7) That the Unit is operated in conformance with NEPOOL CRS's and Operating Procedures, and NEPEX dispatch instructions.

MDPU shall mean the Massachusetts Department of Public Utilities.

NEPOOL shall mean the New England Power Pool. The term "NEPOOL" shall include NEPEX, the central dispatching agency, as defined in Section 15.22 of the NEPOOL Agreement, operating through such satellite dispatching centers as the NEPOOL Management Committee may determine to be appropriate.

NEPOOL Agreement shall mean the New England Power Pool Agreement, dated September 1, 1971, as amended.

Qualifying Facility ("QF") shall mean a cogeneration facility or a small power production facility that meets the requirements of Subpart B of the regulations of the FERC as set forth at 18 C.F.R. 292, et seq., implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2601, et seq.), and is so certified by the FERC in accordance with its procedures.

Seasonal Period shall mean either the Summer Period, June through September, or the Winter Period, October through May, as appropriate.

System Emergency shall mean an imminent condition on the Company's or a neighboring utility's system that is likely to result in significant disruption of service or is likely to endanger life or property.

Testing Period shall mean any period during which the Unit is being tested and may produce electric energy prior to the Actual In-Service Date.

Test Power shall mean any electric energy produced by the Unit during the Testing Period.

ARTICLE 2. Sale of Power.

2.1 The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of the Company's Entitlement of electric capacity and related energy produced by the Unit during the term of this Agreement; provided, however, that in

no event shall the Company be obligated to purchase electric capacity and related energy in excess of twenty-six megawatts (26 MW) during the Summer Period and twenty-nine and one-half megawatts (29.5 MW) during the Winter Period; and provided further, that in no event shall the Company be obligated to purchase and take delivery of related energy in excess of twenty-eight megawatts (28 MW) per hour during the Summer Period and thirty megawatts (30 MW) per hour during the Winter Period, except for those hours during which NEPOOL has ordered the Unit to be operated under Operating Procedure 4 conditions. The Seller may refrain from selling and delivering such electric energy as it may need from time to time to satisfy Unit requirements.

2.2 The Unit shall be staffed, tested, operated, and maintained in accordance with Good Utility Practice and in a manner consistent with the standards applicable to generating facilities owned and operated by participants in NEPOOL, as such standards may be in effect from time to time during the term of this Agreement. The Seller also agrees to make the Unit available for NEPOOL dispatch in accordance with the provisions of Section 12.2 of the NEPOOL Agreement.

2.3 In addition to the foregoing, the Seller shall undergo upon the request of the Company periodic Capability Audits.

2.3.1 In the event that the Unit demonstrates a Capacity Deficiency in excess of one megawatt (1 MW) (the "Threshold Amount"), the Company may assess the Seller an offset charge each month, which charge shall be equal to one twelfth (1/12) of the sum of the annual Capability Responsibility Adjustment Charge plus the annual Capability Responsibility Deficiency Charge, established from time to time by NEPOOL pursuant to the provisions of Section 9.4 of the NEPOOL Agreement, multiplied by such Capacity Deficiency.

2.3.2 In the event that the Unit demonstrates a Capacity Deficiency not in excess of the Threshold Amount, the Company may assess the Seller an offset charge therefor only if and to the extent that the Company is assessed any charges by NEPOOL as a result of such Capacity Deficiency.

2.4 During the Testing Period, the Unit may generate Test Power. The Company agrees to take and pay for any Test Power offered for sale, up to the Company's Entitlement thereof, subject to the following conditions: (i) the tests conducted during the Testing Period shall be performed in accordance with Good Utility Practice, (ii) the administrative committee established pursuant to Article 17.6 of this Agreement shall be kept informed of operations during the Test Period, and (iii) the Company shall pay for any Test Power monthly at a price determined pursuant to the Company's effective, generally available Rate P-1 "Power Purchase" rate (as of the date hereof, MDPU No. 404), or any generally available replacement therefor as may be issued by the Company from time to time.

ARTICLE 3. Effective Date and Term.

3.1 This Agreement shall become effective when all necessary approvals have been received, in a form acceptable to both parties, from the MDPU; provided, however, that the Company's obligation to purchase electric capacity and related energy (other than pursuant to Article 2.4 of this Agreement) shall not commence until the Actual In-Service Date. Unless sooner terminated in accordance with any applicable

provision hereof, this Agreement shall remain in full force and effect until December 31, 2011.

3.2 If all transmission services necessary to deliver power hereunder have not been secured within twenty-four (24) months following the date first above-written, either party may terminate this Agreement upon sixty (60) days written notice to the other.

ARTICLE 4. Dispatchability.

4.1 The Unit shall be subject to Economic Dispatch at the direction of the Company or NEPOOL; provided, however, that the Unit shall be subject to Economic Dispatch at the sole direction of NEPOOL if, and only if, such dispatch is fully in accordance with the provisions of this Article 4. The Company or NEPOOL, as appropriate, may call for up to three hundred (300) stops (that is, when the Unit is to be reduced to a zero percent (0%) load level) and up to three hundred (300) restarts of the Unit per year. The Unit shall be subject to changes in the level of its output at the direction of the Company or NEPOOL, as appropriate, provided that such changes are within the Unit's reasonable design limitations.

4.2 Subject to the provisions of Article 10 of this Agreement, if the Seller fails to dispatch the Unit as called for by the Company or NEPOOL, as appropriate, then the following terms and conditions shall apply:

4.2.1 Company shall calculate the uneconomic incremental production costs it incurs that are attributable to such failure of the Seller (the "Incremental Production Cost Penalty"). The Company shall also not pay for any electric energy produced at the Unit as a result of the Seller's failure to comply with the calls of the Company or NEPOOL, as appropriate, pursuant to Article 4.1 above. The Incremental Production Cost Penalty shall be the amount, if any, by which the production costs that the Company experienced during the period of the Seller's failure to dispatch the Unit as called for by the Company or NEPOOL, as appropriate, exceed the production costs that the Company would have experienced during such period had the Seller complied with the call of the Company or NEPOOL, as appropriate, to dispatch the Unit.

4.2.2 Notwithstanding the foregoing, if and to the extent that the dispatch of the Unit, as prescribed in Article 4.1, becomes proscribed because the Seller has declared that it must operate the Unit under a minimum load level of forty-four (44) megawatts (or less), then the provisions of Article 4.2.1 relating to the Incremental Production Cost Penalty shall not apply; provided, however, that such condition may not exceed two-thousand (2,000) hours in any calendar year, nor shall the aggregate share of the Company's and its affiliate Commonwealth Electric Company (which pursuant to an agreement between it and the Seller, dated as of the date hereof, is purchasing an equal percentage of the electric capacity and related energy to be produced by the Unit) of such minimum load exceed fifteen (15) megawatts; and provided further that this Article 4.2.2 shall apply only so long as a FERC-approved system exchange agreement with New England Power Company in respect of the electric energy resulting by reason of such minimum load condition is in place.

4.3 The Company shall net any Incremental Production Cost Penalty against any payments due the Seller for any electric capacity and energy purchased by the

Billing Amount for a Billing Period is owed to the Company, such Net Billing Amount shall be billed to the Seller and the Seller shall reimburse the Company therefor according to the same standards as are established for payments to the Seller.

ARTICLE 5. Purchase Price.

From and after the Actual In-Service Date, the Company shall pay the Seller each month, in accordance with the provisions of Article 8 of this Agreement, an amount equal to the Total Purchase Price, as determined in accordance with Appendix B attached hereto.

ARTICLE 6. Delivery by the Seller.

6.1 The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electric energy at or near the Design Capacity on a continuous twenty-four (24) hour basis for the full term of this Agreement. The Seller agrees that it will limit its sales of the thermal output of the Unit to two hundred thousand thirty-one (231,000) pounds per hour unless, in the judgment of the Company, any increased sales would not adversely affect the ability of the Seller to be capable of so operating the Unit and of fulfilling its obligations under this Agreement.

6.2 As of the date hereof, the parties expect that the Delivery Point will consist of a point of interconnection between the Company's and an adjacent utility's transmission systems of three hundred forty-five thousand volts (345 kV) nominal (the "Interconnection Voltage"). The parties recognize that it could become necessary or appropriate in the future to designate a different point of interconnection between the Company's and an adjacent utility's transmission systems of a differing voltage, such as one hundred fifteen thousand volts (115 kV) nominal. In the event that the parties so agree in the future, the Interconnection Voltage shall be defined accordingly, and further, the Company shall be entitled to recalculate any wheeling losses reflected in the definition of "Delivered Energy" contained in Article 1 of this Agreement. In any case, electric energy generated by the Unit shall be delivered to the Company at the Delivery Point in the form of three (3) phase, sixty (60) hertz, alternating current at the Interconnection Voltage.

6.3 The Seller may from time to time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance or repair upon the Unit. The Seller shall comply with the provisions of NEPOOL Operating Procedure No. 5 as in effect from time to time when planning any scheduled maintenance or repair upon the Unit. If the Seller should fail to comply with such NEPOOL Operating Procedure, then the Company may assess the Seller a charge each Billing Period during which such non-compliance occurs, which charge shall be calculated and collected pursuant to the provisions of Articles 4.2 and 4.3 of this Agreement governing the Incremental Production Cost Penalty. The Seller shall promptly inform the Company, both orally and in writing, of each scheduled or unscheduled withdrawal of the Unit from service, and shall notify the Company of the reasons therefor and the expected duration thereof when such information is known.

ARTICLE 7. Meters and Metering.

7.1 The Company shall review and approve the metering installations required to record the quantities of electricity purchased from the Seller, such approval not to be unreasonably withheld. Such metering equipment will be capable, inter alia, of providing data required to determine kilowatts purchased during each hour of the month as well as total kilowatthours purchased each month under the terms of this Agreement. The Seller shall install, own, operate, and maintain such metering equipment, which equipment shall be located at the Seller's high voltage bus or buses. If, for any reason, it is impractical to install meters at such bus or buses, appropriate adjustments shall be made to reflect the actual amount of electric energy that would have been recorded by meters located at such bus or buses, as agreed to by the Company and the Seller.

7.2 The Seller shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards. The metering equipment shall be sealed, and the Seller shall comply with any reasonable request of the Company with regard to the presence of the Company's representative when such seals are to be broken or when the meters are to be inspected, tested, or adjusted. The Company may at any time request a test of the accuracy of any metering equipment installed pursuant hereto and shall bear the costs thereof in the event that said requests are made more frequently than once in each twelve (12) months. The results of all meter calibrations or tests, regardless of whether performed at the Company's request, shall be open to examination by the Company at all reasonable times.

7.3 Any meter tested and found to register less than or equal to one half of one percent (0.5%) above or below the recognized comparative standard shall be considered correct and accurate. If the metering fails to operate or, as a result of such tests, the metering equipment is found to be defective or inaccurate, the Seller shall restore it to a condition of accuracy or replace it. In such event, appropriate adjustments shall be agreed to by the Seller and the Company and reflected in the next monthly statement of the Seller rendered pursuant to Article 8.1 of this Agreement. Such adjustments shall correct all measurements made by the defective or inaccurate meter for either (i) the actual period during which inaccurate measurements were made, if determinable to the mutual satisfaction of the Company and the Seller, or (ii) if such period is not determinable, for a period equal to one half of the time elapsed since the last prior test, but in no event greater than twelve (12) months.

7.4 Other provisions of this Article notwithstanding, the Company may elect to install its own metering equipment in supplement to the Seller's metering equipment. Should any metering equipment installed by the Seller fail to register the amount of electric energy delivered to the Company during any period, the Company's metering equipment shall, if so installed, be used to determine the amount of electric energy so delivered. If the Company wishes its metering equipment to be so used, the Company agrees to operate, maintain, and read such equipment according to the standard established by this Article with respect to the Seller's metering equipment. The Seller agrees, upon the request of the Company, to provide a suitable location at the Site for installation of the Company's meters at no cost to the Company.

7.5 Upon the written request of the Company, the Seller shall install, own, operate, and maintain, pursuant to the provisions of this Article, such telemetering equipment and data circuits as the Company may reasonably require for the transmission of various metered values to its operations center. The design equipment and data circuits shall

be approved by the Company prior to their installation by the Seller, such approval not to be unreasonably withheld. Upon the failure of the Seller to install such telemetering equipment and data circuits within a reasonable period following the request of the Company to do so, the Company may install such equipment and data circuits at the expense of the Seller.

ARTICLE 8. Billing and Payment.

8.1 The Seller shall render monthly statements for the Billing Period then most recently ended within ten (10) business days following the close of such Billing Period, detailing the amount of Delivered Energy during such Billing Period. Any amount payable hereunder not paid within thirty (30) days from the date of receipt by the Company of such monthly statement (or, if such date is not a business day, then by the next business day thereafter) shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current prime interest rate on commercial loans then in effect at the First National Bank of Boston from the date of such receipt of such monthly statement until the date of payment.

8.2 In the event that any data required for billing purposes hereunder are unavailable when needed for such billing, the unavailable data may be estimated by the Seller, subject to any required adjustment, based upon actual data, in a subsequent Billing Period. The Seller shall make all data upon which any estimated data are based available to the Company. No late payment charge shall be imposed on amounts owed by the Company to the Seller, or by the Seller to the Company, as a result of any such subsequent adjustment.

8.3 Neither the Company nor the Seller shall have the right to challenge any monthly statement rendered or received hereunder, to invoke arbitration of the same, or to bring any court or administrative action of any kind questioning the propriety of said monthly statement, after a period of one (1) year from the date such monthly statement was rendered. In the event that any such monthly statement depends in whole or part upon estimated data, this one (1) year limitation period shall be deemed to begin in the Billing Period in which such estimated data are adjusted to actual.

ARTICLE 9. Governmental Regulation.

9.1 As soon as practicable after execution, this Agreement shall be submitted by the Company to the MDPU in accordance with the regulations of the MDPU as set forth at 220 C.M.R. 8.00.

9.2 Each party hereto shall be responsible for taking all necessary actions to satisfy any regulatory requirements that may be imposed by any federal, state, or municipal statute, rule, regulation, or ordinance that may be in effect from time to time relative to the performance of such party hereunder.

9.3 This Agreement and all rights and obligations of the parties hereunder are subject to all applicable state and federal laws and all duly promulgated orders and duly authorized actions of governmental authorities.

ARTICLE 10. Liability and Force Majeure.

10.1 The parties hereto shall be excused from performing hereunder and shall not be liable in damages or otherwise if and to the extent that they are unable to do so or are prevented from doing so by statute or regulation, or by action of any court or public authority having or purporting to have jurisdiction in the premises; or by reasons of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or regulatory agency, or any other cause, regardless of whether similar thereto, beyond the reasonable control of the affected party. Each party shall have the obligation to operate in accordance with Good Utility Practice at all times and to use diligent effort to overcome and remove any cause of failure to perform. The party subject to any such event of force majeure shall promptly inform the other party thereof, both orally and in writing, setting forth the nature of such event and its expected duration.

10.2 Neither the Company nor the Seller shall, in any event, be liable to the other or to any third party for any consequential, indirect, or special damages to persons or property, whether arising in tort, contract, or otherwise, by reason of this Agreement or any services performed or undertaken to be performed by the Company or the Seller hereunder.

10.3 Whenever the Company's system or any system with which it is directly or indirectly interconnected experiences a System Emergency, or whenever it is necessary or desirable to aid in the restoration of service on its system or on any system with which it is directly or indirectly interconnected, the Company may, in its reasonable judgment, curtail or interrupt the taking of electric energy hereunder, provided such curtailment or interruption shall continue only for so long as is reasonably necessary. Such curtailment, interruption, or reduction shall not be deemed to be a default by the Company nor shall the Company be liable therefor to the Seller or to any other party. The Company will provide the Seller with such notice as is reasonably practical under the circumstances regarding the nature, extent, and expected duration of a System Emergency.

10.4 The Company and the Seller agree that each shall be responsible for the electricity on its respective side of the Delivery Point and shall indemnify, save harmless, and defend the other against all claims, demands, costs, or expenses for loss, damage, or injury to persons or property in any manner directly or indirectly arising from, connected with, or growing out of the presence, use, or transmission of electricity over the wires, cables, devices, or appurtenances owned by it. The Company and the Seller each assumes full responsibility in connection with the service rendered hereunder for its respective wires, cables, and other devices used in connection with such service. Each party hereto shall be solely liable for all claims of its own employees arising from any worker's compensation laws.

10.5 Neither by inspection, by non-rejection, nor in any other way does either party give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any equipment, apparatus, or devices installed on the other party's premises.

ARTICLE 11. Governing Law.

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the Commonwealth of Massachusetts.

ARTICLE 12. Arbitration.

12.1 In the case of any dispute between the parties with respect to the interpretation of this Agreement or the performance of the same, either party may give notice in writing to the other of its desire to submit such questions to arbitration and may designate an arbitrator. Within thirty (30) days after the receipt of such notice the other party may, in writing, serve upon the party invoking such arbitration a notice designating an arbitrator on its behalf. The two arbitrators so chosen shall, within twenty (20) days after the appointment of the second arbitrator, in writing, designate a third arbitrator. Upon the failure of the party notified to appoint the second arbitrator within such time, the party invoking such arbitration may proceed with the single arbitrator. If the first and second arbitrators are unable to agree on a third arbitrator within twenty (20) days of the appointment of the second arbitrator, the first and second arbitrator shall invoke the services of the American Arbitration Association to appoint a third arbitrator. This third arbitrator shall, to the extent practicable, have special competence and experience with respect to the subject matter under consideration. An arbitrator so appointed shall have full authority to act pursuant to this Article. No arbitrator, whether chosen by a party hereto or appointed, shall have the power to amend or add to this Agreement. Unless the parties otherwise agree, the place of any arbitration held pursuant to this Article 12 shall be Boston, Massachusetts.

12.2 The party calling the arbitration shall, within twenty (20) days after either the failure of the other party to name an arbitrator or the appointment of the third arbitrator, as the case may be, fix, in writing, a time and a place of hearing, to be not less than twenty (20) days from the delivery of notice to the other party. The arbitrator or arbitrators (the "Arbitrators") shall, thereupon, proceed promptly to hear and determine the controversy pursuant to the then current rules of the American Arbitration Association for the conduct of commercial arbitration proceedings, except that if such rules conflict with the then current provisions of the laws of the Commonwealth of Massachusetts relating to arbitration, such conflict shall be governed by the then current provisions of such laws of the Commonwealth of Massachusetts. The Arbitrators shall fix a time within which the matter shall be submitted to them by either or both of the parties, and shall render a decision within ten (10) days after the final submission from the parties to them unless, for good reasons to be certified by them in writing, the Arbitrators extend such time. The decision of the single arbitrator, or two of the three arbitrators, shall be taken as the arbitration decision. Such decision shall be made in writing and in duplicate, and one copy shall be delivered to each of the parties. The arbitrators by their award shall determine the manner in which the expenses of the arbitration shall be borne, except that each party shall pay the costs of its own counsel. Each party shall accept and abide by the arbitration decision. The award of the Arbitrators shall be final except as otherwise provided by applicable law. Judgment upon such award may be entered by the prevailing party in any court having jurisdiction thereof, or application may be made by such party to any such court for judicial acceptance of such award and an order of enforcement.

12.3 The party on which a demand for arbitration pursuant to this Article 12 is served shall have the right to remove the dispute that is the subject of such a demand by petitioning an appropriate regulatory forum where such dispute can receive recognition and cognizance (including, without limitation, the MDPU and the FERC); provided however, that such right shall not apply to disputes that involve

issues wholly operational or technical; and provided further, that in the event the applicable regulatory agency does not from the date of such petition: (i) accept the petition for jurisdiction within thirty (30) days; (ii) conduct and commence adjudicatory hearings (as applicable) within sixty (60) days; or (iii) issue a decision on the subject dispute within one-hundred eighty (180) days, then the party calling the arbitration shall have the right to invoke the arbitration process in accordance with Paragraphs 12.1 and 12.2, above.

ARTICLE 13. Insurance.

13.1 From and after the Actual In-Service Date, the Seller shall (i) keep the Unit insured, at all times, by means of a policy or policies of insurance, in amounts not less than that reasonably required by the Company, protecting against loss or damage to the Unit by fire, lightning, and other casualties normally insured against with a uniform standard extended coverage endorsement; and (ii) maintain comprehensive general liability insurance as described in Appendix C attached hereto. The Company shall be a named insured in these policies, which policies shall contain a waiver of subrogation in favor of the named insured. All policies, or copies thereof, together with a certificate from the insurers evidencing that the policies are currently in force, shall be delivered to the Company.

13.2 Such insurance shall be provided by policies that shall be written by such companies and in such form as shall be generally commercially available and acceptable to the Company, such acceptance not to be unreasonably withheld; shall be primary and without right to contribution from other insurance that may be available; shall provide that, with respect to the Company, the insurance shall not be invalidated by any action or inaction by the Seller including, without limitation, any representation made by or on behalf of the Seller in the procurement of such insurance; and shall provide that such insurance shall not be canceled or amended without at least thirty (30) days prior written notice to the Company.

13.3 Not less than thirty (30) days prior to the expiration date of each policy obtained by the Seller in accordance with this Article, the Seller shall deliver to the Company a renewal policy or policies accompanied by evidence of payment of the premium therefor.

13.4 The amount of any proceeds of insurance described in this Article remaining after deducting all expenses (including attorney fees) incurred in the collection of such proceeds from the gross proceeds thereof shall be applied to the prompt repair, restoration, modification, or improvement of that portion of the Unit damaged or destroyed by such casualty, unless the Seller and the Company (in coordination with other purchasers) have agreed that such repair, restoration, modification, or improvement is not practicable under the circumstances.

ARTICLE 14. Preservation of the Unit.

14.1 The Seller in its sound discretion may sell or otherwise dispose of only that machinery, equipment, or other personal property constituting part of the Unit that the Seller determines has become inadequate, obsolete, worn out, unsuitable, undesirable, or unnecessary, provided that (i) substitute property having equal or greater utility, but not necessarily the same function, in the operation of the Unit is installed at the Unit and such removal and substitution would not materially impair

the efficiency of operation of the Unit, adversely affect the structural integrity or electrical output of the Unit, or change the nature of the Unit to the extent that it would not constitute the type of electricity generation facility operated prior to such replacement; and (ii) the prior written consent of the Company is obtained, which consent shall not be unreasonably withheld, and which consent shall not be required for removals and substitutions made during the course of ordinary and routine repair and maintenance. The Seller shall promptly report to the Company each such removal, substitution, sale, or other disposition. In addition, not less often than semi-annually, the Seller shall make available to the Company's representatives on the administrative committee described in Article 17.6 of this Agreement all records with respect to prior dispositions and substitutions, together with information as to planned dispositions and substitutions during the next six (6) months.

14.2 The Seller shall pay or cause to be paid all taxes, payments in lieu of taxes, assessments, and other charges now or hereafter levied against the Unit or any part thereof, together with any penalties or interest on any of the foregoing; subject to the right of the Seller and other parties in interest to contest in good faith the levying of such charges. The Seller shall promptly notify the Company as to any impending lien to be imposed upon the Site due to the nonpayment of any such charges, and upon the request of the Company, shall exhibit to the Company receipts for the payment thereof.

14.3 The Seller warrants that it holds, and that at the time security will be furnished to the Company pursuant to Article 15 it will hold, a leasehold interest in the Site for the full anticipated term of this Agreement, subject only to any mortgages, liens, leases, or other encumbrances existing as of record and copies of which will have been provided to the Company at the time of furnishing such security. The Seller also warrants that it holds, and that at the time security will be furnished to the Company pursuant to Article 15 it will hold, either a leasehold interest in the Unit for the full anticipated term of this Agreement or good record and marketable title to the Unit, subject only to any mortgages, liens, or other encumbrances existing as of record and copies of which will have been provided to the Company at the time of furnishing such security. The Seller shall not enter into any transaction involving the transfer, sale, or lease of the Site or the Unit, or any interest therein, without the prior written consent of the Company in each case obtained, which consent shall not be unreasonably withheld. Such transfer, sale, or lease shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against an entity that might thereby obtain title to or possession of the Site or Unit.

14.4 The Seller will maintain the Unit and the Site, or cause the Unit and the Site to be maintained, in accordance with Good Utility Practice; will not commit or suffer any waste thereof or the conduct of any nuisance or unlawful occupation or business on, or use of, the Unit or the Site; and will comply, or cause compliance, with all statutes, ordinances, and requirements of any governmental authority relating to the Unit and the Site; and the Seller at its expense shall provide the Company with a report, on a biennial basis for the first ten (10) years of the term of this Agreement and on an annual basis thereafter, prepared by a nationally recognized firm of consulting engineers of Seller's choosing and approved by the Company, such approval not to be unreasonably withheld, attesting to the fact that the Unit is being maintained in accordance with Good Utility Practice. If substantial items affecting long-term efficient operation of the Unit that are described in any such annual report as being in need of correction are not corrected within six (6) months following such annual report, the Company may withhold payment each month of that portion of the Total

Purchase price equal to one sixth (1/6) of the amount required to correct such items, with such amounts to be held in escrow by the Company until the cited items have been corrected, upon which correction the escrowed funds shall be released to the Seller. Notwithstanding the foregoing, if any such correction is not made within twelve (12) months from the date of such annual report, the Company may elect to cause such correction to be made and the escrowed funds shall be applied to cover the costs of such correction. In the event that the Seller challenges the validity of any item contained in such report and the parties are unable to resolve upon such item, the matter shall be set for arbitration in accordance with the provisions of Article 12 of this Agreement. No such challenge or arbitration shall affect the Company's rights to withhold and place in escrow amounts necessary to correct such item as set forth herein.

14.5 The Company and any persons authorized by the Company shall have the right to enter and inspect the Unit at all reasonable times upon reasonable prior written notice to the Seller and in coordination with the Lessor's reasonable requirements concerning access to the Site, and to examine Unit operating manuals and maintenance records.

ARTICLE 15. Security of Continued Performance.

The parties to this Agreement acknowledge that the Company and its ratepayers will incur costs hereunder such that the Company and its ratepayers expect to receive full consideration therefor only to the extent that the Seller's obligations hereunder are fully performed and electric capacity and related energy from the Unit are sold to the Company for the full anticipated term of this Agreement. Accordingly, in order to secure such complete performance of the Seller's obligations and the continued sale of electric capacity and related energy from the Unit to the Company, the Seller, prior to the Actual In-Service Date, shall provide to the Company security in the form and scope set forth below.

15.1 Mortgage and Security Agreement. The Seller shall execute and deliver to the Company a mortgage and security agreement creating liens and security interests in the Unit, the Seller's leasehold interest in the Site, all improvements upon the Site, and all rents, profits, income, and other benefits derived from the foregoing, subordinate only to the lien securing amounts lent for the acquisition of the Site and for the construction, establishment, and operation of the Unit; or to the lien of the institutional or unaffiliated lenders securing amounts otherwise lent in respect of the Unit. Such liens and security interests of the Company shall secure (i) all amounts paid by the Company to the Seller pursuant to this Agreement in excess of the Company's actual avoided costs, and (ii) performance of the Seller's obligations under this Agreement for the full anticipated term thereof, including all damages resulting from the Seller's failure to perform such obligations. Such mortgage and security agreement shall be in form and substance acceptable to the Company.

15.2 Declaration of Easements, Covenants, and Restrictions. The Seller shall cause to be granted to the Company an unsubordinated declaration of easements, covenants, and restrictions encumbering the Site for a period equal to the anticipated full term of this Agreement (the "Declaration"), which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. The Declaration shall grant to the Company easements for access to the Site and for the placement and operation of facilities thereon, as well as create restrictions and covenants to the effect that no electricity produced at the Site shall be sold unless and until the Company's Entitlement of such electricity is tendered to the Company in accordance

with this Agreement. The Declaration shall be in form and substance acceptable to the Company, shall run with the Site, shall be binding upon the successors of the Seller, and shall inure to the benefit of the Company and its successors.

15.3 Accommodation Agreement. The Seller shall cause any lender of funds to the Seller for the acquisition of the Site, for the construction, establishment, or operation of Unit, or otherwise in respect of the Unit (the "Lender") to execute and deliver an Accommodation Agreement, which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. Under the Accommodation Agreement, the Lender shall agree: (i) to make its own interests subject to the Declaration; (ii) to honor this Agreement to the extent the Lender is in possession of the Site or Unit; (iii) to transfer interests in the Site or Unit only upon the condition that the transferee become obligated to honor this Agreement; and (iv) not to disturb the Company's enjoyment of rights under this Agreement. The Seller shall similarly cause the Lessor to execute and deliver an Accommodation Agreement, making the interests of the Lessor subject to those of the Company pursuant to the Company's mortgage and security agreement and the Declaration.

15.4 Letter of Credit. The Seller shall provide, in form and substance acceptable to the Company, an irrevocable letter of credit in favor of the Company, which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. The Seller shall maintain such letter of credit throughout the period during which payments by the Company to the Seller are expected to exceed the Company's projected avoided costs, as set forth according to the following schedule:

From	Through	Amount
September 1, 1993	December 31, 1993	$ 377,327
January 1, 1994	December 31, 1994	$2,318,311
January 1, 1995	December 31, 1995	$3,665,206
January 1, 1996	December 31, 1996	$5,108,747
January 1, 1997	December 31, 1997	$5,736,826
January 1, 1998	December 31, 1998	$6,255,072
January 1, 1999	December 31, 1999	$6,142,306
January 1, 2000	December 31, 2000	$4,994,779
January 1, 2001	December 31, 2001	$3,912,748
January 1, 2002	December 31, 2002	$ 359,895

15.5 Coordination with Other Secured Parties. Each of the Company and the Seller (on its own behalf and on behalf of the Lender and the Lessor) agrees to negotiate in good faith reciprocally with respect to accommodating the various interests of the Company, the Lender and the Lessor at the time when the Seller has secured commitments for financing the Unit; provided, however, that the foregoing shall not diminish the obligation of the Seller, the Lender and the Lessor to fulfill the obligations due to be performed respectively by them hereunder. The Company further agrees to liaise with other purchasers of the electric output from the Unit with respect to coordinating their respective entitlements thereto.

ARTICLE 16. Rights of the Company with Respect to Expansion of the Unit and Extension of Unit Life.

The Seller shall not enter into any contract for the sale of electricity from any addition to or expansion of the Unit beyond the Design Capacity, from any other electric generation facilities located at the Site, or for any period beyond the term of this Agreement, until and

unless (i) the Seller shall have first offered to enter into a contract with the Company on terms substantially the same as those specified in any proposal or letter of intent between the Seller and any other party with respect thereto, and (ii) the Company does not accept such offer within thirty (30) days of the date presented to the Company in writing and be ready and willing to enter into a contract reflecting such business terms within sixty (60) days thereafter. The Company acknowledges and understands that other purchasers of electricity produced by the Unit may require similar rights to purchase electric energy generated by additions to or expansion of the Unit and during periods beyond the term of the original power purchase agreements entered into by such other purchasers, and the Company agrees that its rights pursuant to this Article 16 will relate only to such portion of any such expansion or extension as is equal to the Company's Entitlement. The Seller agrees to keep the Company fully and promptly apprised, through the administrative committee described in Article 17.6 of this Agreement, of any plans the Seller may develop for any addition to or expansion of the Unit or the development of any other generation facilities at the Site, which information the Company agrees not to disclose except with the Seller's prior written permission.

ARTICLE 17. Miscellaneous Provisions.

17.1 This Agreement shall constitute the entire agreement between the parties hereto relating to the subject matter hereof, and all previous agreements, discussions, communications, and correspondence with respect to the subject matter hereof shall be superseded by the execution of this Agreement.

17.2 This Agreement may not be modified or amended except in writing signed by or on behalf of both parties by their duly authorized officers.

17.3 In the event that any or all of the NEPOOL standards referred to herein shall cease to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that do not materially alter the obligations of the Seller as such obligations existed under the NEPOOL standards.

17.4 This Agreement shall inure to the benefit of and bind the respective successors and assigns of the parties hereto, provided however, that no assignment by either party (or any successor or assignee thereof) of its rights and obligations hereunder (except an assignment by the Company of such rights and obligations to a wholly-owned subsidiary or an affiliate wholly-owned by the same holding Company, or an assignment by the Seller of such rights and obligations to such a subsidiary or affiliate whose principal functions are to own and operate the Unit), shall be made or become effective without the prior written consent of the other party in each case obtained, which consent shall not be unreasonably withheld. All assignments by the Seller or the Seller's successors and assigns shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against any entity that might obtain title to or possession of the Site or Unit.

17.5 Notwithstanding any assignments of rights or duties hereunder, neither party shall be relieved of any duties or responsibilities under this Agreement and this Agreement shall continue in accordance with its terms and each party shall be and remain liable to the other under all provisions of this Agreement unless the other party has expressly consented in writing to such release of duties and responsibilities, such consent not to be unreasonably withheld. Further, any payments made by one party to an assignee of the other party or any other actions taken by such party with respect

to such assignee shall be in full satisfaction of any duties or responsibilities that the party would otherwise owe to the other party, as if made directly or taken with respect to such other party.

17.6 The parties hereto agree to establish an administrative committee, which shall serve informational functions only. Unless otherwise agreed by the administrative committee, such committee shall meet at least once each calendar quarter prior to the Actual In-Service Date and at least twice each year thereafter. The Company and the Seller shall have equal representation upon such committee.

17.7 The Company's obligations hereunder are conditioned upon the Unit being certified, on the Actual In-Service Date, as a Qualifying Facility. Further, the Seller shall use its best efforts to maintain such certification of QF status throughout the term of this Agreement. If, despite such efforts, certification of the Unit's QF status is revoked, suspended, or otherwise terminated after the Actual In-Service Date, the Seller shall use its best efforts to regain such certification and the Company and the Seller agree to continue to purchase and sell electric capacity and related energy from the Unit in accordance with the terms of this Agreement, including, without limitation, the purchase price provisions of Article 5 of this Agreement.

17.8 Any written notice required to be given hereunder shall be given by certified or registered mail, postage prepaid, return receipt requested, or by hand or personal delivery, at the addresses specified below, or at such other addresses as may be specified in writing by the party in question:

To the Seller: Howard D. Lutz, President
Altresco Financial, Inc.
Suite 1200
600 S. Cherry Street
Denver, Colorado 80222

(with a copy to: David S. Rosenzweig, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, Massachusetts 02110)

To the Company: Cambridge Electric Light Company
2421 Cranberry Highway
Wareham, Massachusetts 02571
Attention: Michael R. Kirkwood

(with a copy to: Michael F. Donlan, Esq.
Rich, May, Bilodeau & Flaherty, P.C.
294 Washington Street
Boston, Massachusetts 02108)

Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept.

17.9 If any provision of this Agreement is found to be prohibited or unenforceable, the remainder of this Agreement shall not be affected thereby and shall be valid and enforceable to the extent permitted by law.

In witness whereof, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

ALTRESCO PITTSFIELD, L.P.

By Altresco, Inc.,

Its General Partner.

By _____,

Its Vice President.

CAMBRIDGE ELECTRIC LIGHT COMPANY

By _____,

Its _____.

17.9 If any provision of this Agreement is found to be prohibited or unenforceable, the remainder of this Agreement shall not be affected thereby and shall be valid and enforceable to the extent permitted by law.

In witness whereof, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

ALTRESCO PITTSFIELD, L.P.

By Altresco, Inc.,

Its General Partner.

By _____,

Its _____.

CAMBRIDGE ELECTRIC LIGHT COMPANY

By _____,

Its President & Chief Operating Officer.

APPENDIX A

DESCRIPTION OF SITE

The Unit is located at the General Electric Plastics and Ordinance Groups' facility in Pittsfield, Massachusetts. The Site Lease and Steam Sale Agreement have been executed with General Electric.

The base plant configuration is a combined cycle power plant featuring three General Electric combustion turbine generators (GTGs), three heat recovery steam generators (HRSGs), a single condensing steam turbine (STG) with water cooled condenser, and supporting systems required for safe, environmentally sound, reliable and economic plant operation.

The supplementary fired HRSGs will supply high pressure superheated steam to the steam turbine to produce a nominal 40 MW of electricity augmenting the nominal 40 MW from each GTG. After subtracting auxiliary loads, the estimated total plant net electrical output is a nominal 160 MW at annual average conditions. Approximately 78,000 lb/hr of 210 psig process steam will be let down from the HRSG high pressure header system and delivered to General Electric's facility.

The cogeneration project occupies approximately 5.0 acres of area within the General Electric facility.

The facility has contracts to supply fuel utilizing a 365-day firm supply of natural gas, with facility requirements at approximately 31.5 million cubic feet per day (MMCFPD).

In the event of an emergency gas supply interruption, the Unit is capable of burning low sulfur distillate fuel oil as a backup fuel.

This Unit has been in commercial operation since August, 1990.

APPENDIX B

1. Total Purchase Price

Each Billing Period, commencing with the Actual In-Service Date, the Company shall pay to the Seller the Total Purchase Price, in accordance with the following formula:

Total Purchase Price = Monthly Capacity Charge + Monthly Energy Charge + Monthly Gas Transportation Demand Cost + Monthly Capital Cost + Transmission Charge,

> Where Monthly Capacity Charge is defined and computed as set forth in Section 2 of this Appendix B, Monthly Energy Charge is defined and computed as set forth in Section 3 of this Appendix B, Monthly Gas Transportation Demand Cost is defined and computed as set forth in Section 4 of this Appendix B, Monthly Capital Cost is defined and computed as set forth in Section 5 of this Appendix B, and Transmission Charge is defined and computed as set forth in Section 7 of this Appendix B; provided, however, that for every Billing Period following the fifteenth (15th) anniversary of the Actual In-Service Date through the remaining term of this Agreement, the Total Purchase Price shall not exceed an amount equal to the sum of (i) the Company's actual avoided costs for the Company's Capacity Entitlement, which avoided costs shall be calculated by the Company, on a per-megawatt (per-MW) basis, and furnished to the Seller prior to such fifteenth (15th) anniversary, plus (ii) the Company's actual avoided cost for the Delivered Energy, as determined pursuant to the Company's effective, generally available Rate P-1 "Power Purchase" rate or any generally available replacement therefor as may be issued by the Company from time to time.

The following definition shall be used in this Appendix B:

Company's Available Kilowatthours shall be equal to the product of (i) the actual Equivalent Availability Factor for the Unit during the applicable Billing Period as calculated in accordance with NEPOOL CRS No. 33, as amended and supplemented from time to time, and as reported in the NEPOOL document entitled "Interim Report for NEPOOL Capability Responsibility"; multiplied by (ii) the Company's Capacity Entitlement; multiplied by (iii) the number of hours in the applicable Billing Period.

2. Monthly Capacity Charge

The Monthly Capacity Charge shall be equal to the product of (i) the Company's Capacity Entitlement; (ii) four dollars and fifty-one cents per kilowatt ($4.51/kW); (iii) an index factor represented by the quantity K/L; and (iv) the Availability Adjustment, defined and computed as set forth in Section 6 of this Appendix B;

> Where K shall be equal to 134.7 through calendar year 1990; and, in each calendar year thereafter, K shall be equal to the Consumer Price Index for Urban Wage Earners and Clerical Workers, unadjusted for seasonal

variations, 1982-1984 = 100, all items indexed for Boston, Massachusetts, as published in the Bureau of Labor Statistics' CPI Detailed Report (the "CPI Index") for November of the preceding calendar year, provided, however, that if a CPI Index is not published for November, then K shall be equal to the CPI Index for the first preceding month for which a CPI Index is published, and

Where L shall be equal to 134.7, which is the CPI Index for November 1989.

3. Monthly Energy Charge

The Monthly Energy Charge shall be equal to the product of (i) the Delivered Energy and (ii) the Kilowatthour Charge:

where the Kilowatthour Charge is equal to the product of (i) one and thirty-six hundredths cents per kilowatthour ($0.0136/kWh) and (ii) an index factor represented by the quantity M/N,

where M shall be equal to the monthly weighted average sum of the following three fuel components, where each is expressed in dollars per MMBtu: (i) 50% weighting for the monthly average of the daily quotes for No. 6 oil (2.2% sulfur) in Platt's Oilgram, Estimated New York Harbor Spot Price, low cargo quotation, assuming 6.3 MMBtu per barrel; (ii) 40% weighting for the Tennessee Gas Pipeline Company's Current Average Cost of Purchased Gas (or its successor rate) as specified in Tennessee Gas Pipeline Company's FERC Gas Tariff; and (iii) 10% weighting for New England Power Company's weighted average delivered cost of coal as reported in the most recently submitted FERC Form 423; and

where N is $2.05/MMBtu.

Commencing on the fifth (5th) anniversary of the Actual In-Service Date pursuant to this Agreement, either the Company or the Seller shall have the right, exercisable not more than once every five years during the remainder of the term of this Agreement, to require renegotiation of the pricing provisions in this Appendix by written notice. The purpose of any such renegotiation shall be to modify Monthly Energy Charge, above, in a manner that will: (i) achieve a price of gas that, taking into account the cost of transportation to the Unit, is competitive with and comparable to the prices of long-term, firm baseload supplies delivered at the city gate to local distribution companies in Connecticut, Massachusetts, and Rhode Island; and (ii) achieve a price of gas that will allow the Unit to be dispatched as a baseload fossil fuel electric generating plant operating at a capacity factor (equal to Net Electric Output divided by the product of the number of hours in a year times the Unit's Design Capacity) of seventy-five percent (75%). In the event the two preceding objectives of any renegotiation are in conflict, the second provision, relating to baseload operation at a seventy-five percent (75%) capacity factor, shall prevail. The Company and the Seller agree that the Kilowatthour Charge shall not be increased or decreased by more than seven and one-half percent (7.5%) at the time of any such renegotiation. The Company and Seller further agree that the base value of the Kilowatthour Charge shall be redefined at the time of any renegotiation in the following manner. In the month following any increase or decrease in the Kilowatthour Charge as a result of renegotiation, the numeric component of the Kilowatthour Charge (i.e., $0.0136 per kilowatthour) shall be set equal to the value of the Kilowatthour Charge for the month in which the value of the Kilowatthour Charge was increased or

decreased as a result of the renegotiation. The value of "M" shall be as defined above. The value of "N" shall be equal to the value of "M" for the month in which the value of the Kilowatthour Charge was increased or decreased as a result of renegotiation.

Notwithstanding the above, in the event that the Seller must operate the Unit under a minimum load level, as described in Article 4.2.2 of this Agreement, the Company shall pay the Seller on a monthly basis, for all kilowatthours produced at such minimum load level (within the limitations set forth in Article 4.2.2), the product of (a) the Delivered Energy, and (b) the Minimum Load Energy Charge, where the Minimum Load Energy Charge shall be the lesser of:

(i) ninety percent (90%) of "G", as defined and calculated in accordance with Article V(B) of New England Power Company's ("NEP") December 9, 1987 Agreement with the Seller with respect to the Unit (the "1987 Agreement"), as amended and as in effect from time to time, or

(ii) "Rate Y", as defined and calculated in accordance with Schedule H of the 1987 Agreement.

At the beginning of each Billing Period, NEP shall calculate and provide to the Company the value of "G" and "Rate Y" for such Billing Period. Such calculations shall be based on the best information available to NEP at the time they are made. Subsequent true-ups to reflect actuals shall not be made.

4. Monthly Gas Transportation Demand Cost

The Monthly Gas Transportation Demand Cost shall be equal to the product of (i) the Company's Available Kilowatthours during the applicable Billing Period, and (ii) the following amounts during each calendar year:

Contract Year		Contract Year	
1992:	$0.0174/kWh	2002:	$0.0201/kWh
1993:	0.0169	2003:	0.0204
1994:	0.0168	2004:	0.0206
1995:	0.0169	2005:	0.0209
1996:	0.0171	2006:	0.0213
1997:	0.0172	2007:	0.0217
1998:	0.0173	2008:	0.0221
1999:	0.0193	2009:	0.0226
2000:	0.0196	2010:	0.0231
2001:	0.0198	2011:	0.0236

5. Monthly Capital Cost

The Monthly Capital Cost shall be equal to the product of (i) the Company's Available Kilowatthours during the applicable Billing Period, and (ii) two and eighteen-hundredths cents per kilowatthour ($0.0218/kWh).

6. Availability Adjustment

Each Billing Period, the Availability Adjustment shall be applied to the Monthly Capacity Charge, based on the ability of the Seller to operate the Unit as measured on a moving, twelve month, cumulative equivalent availability factor basis. The Availability Adjustment shall be determined each Billing Period in accordance with the following:

$$\text{Availability Adjustment} = \frac{EAF}{0.8725};$$

provided, however, that if EAF minus 0.8725 is greater than or equal to -0.05 and less than or equal to +0.05 in the applicable Billing Period, then the Availability Adjustment shall equal 1; and

Where EAF is equal to the moving-average cumulative Equivalent Availability Factor for the Unit for the preceding twelve (12) Billing Periods as calculated in accordance with NEPOOL CRS No. 33, as amended and supplemented from time to time, and as reported in the NEPOOL document entitled "Interim Report for NEPOOL Capability Responsibility"; provided, however, that EAF shall never exceed a value of 1.

7. Transmission Charge

The Transmission Charge shall be the incremental transmission costs actually incurred by the Seller and necessary to wheel the Unit's capacity and related energy to the Company through the Boston Edison Company system to the Delivery Point pursuant to Boston Edison Company's applicable FERC-approved transmission tariff as amended from time-to-time; provided, however, the Transmission Charge payable by the Company hereunder to the Seller shall not exceed fifteen dollars ($15) per kilowatt-year.

8. In the event that any or all of the indices or publications referred to in this Appendix B shall cease to be established or published, the Company and the Seller shall agree upon reasonable substitute indices or publications.

APPENDIX C

LIABILITY INSURANCE

From and after the Actual In-Service Date, the Seller shall take out, carry, and maintain, or cause to be taken out, carried, and maintained, comprehensive general liability insurance, including automobile and contractual liability, and liability arising out of aircraft or watercraft, if applicable, with a combined single limit per occurrence of a least five million dollars ($5,000,000) applicable to bodily injury, sickness or death, and loss of or damage to property, subject to an aggregate limit of not less than five million dollars ($5,000,000) for products and completed operations.

AMENDMENT

TO

POWER SALE AGREEMENT

BETWEEN

CAMBRIDGE ELECTRIC LIGHT COMPANY

AND

ALTRESCO PITTSFIELD LIMITED PARTNERSHIP

[1A-72]

AMENDMENT TO POWER SALE AGREEMENT
BY AND BETWEEN CAMBRIDGE ELECTRIC LIGHT COMPANY
AND ALTRESCO PITTSFIELD, L.P.

AMENDMENT dated as of this 7th day of ~~October~~ November, 1994, by and between Cambridge Electric Light Company, a Massachusetts corporation with a usual place of business at 2421 Cranberry Highway, Wareham, Massachusetts ("Company") and Altresco Pittsfield, L.P., a Delaware limited partnership with a principal place of business at One Bowdoin Square, Boston, Massachusetts ("Seller"), to the Power Sale Agreement dated February 20, 1992 ("Agreement").

WHEREAS the Company, pursuant to the Agreement and subject specifically to the provisions contained in Article 2.1 of the Agreement, purchases 17.2 percent of the electricity produced by the Seller's electric cogeneration facility, which is capable of generating approximately one-hundred sixty (160) megawatts ("MW") of electricity and which is located at a site owned by General Electric in Pittsfield, Massachusetts (the "Facility" or "Unit"); and

WHEREAS, the Total Purchase Price for electricity purchased by the Company pursuant to Section 1 of Appendix B of the Agreement includes a component known as the Monthly Energy Charge, which component is defined in Section 3 of Appendix B of the Agreement; and

WHEREAS, the Monthly Energy Charge is calculated, in part, by reference to the Tennessee Gas Pipeline Company's ("Tennessee") Current Average Cost of Purchased Gas, also known as the Weighted Average Cost of Gas ("WACOG"), or its successor index, as specified in Tennessee's approved Federal Energy Regulatory Commission ("FERC") Gas Tariff; and

WHEREAS, Tennessee's WACOG ceased to be available as of July, 1992 as a consequence of the restructuring of Tennessee's services pursuant to FERC Order No. 636, and no successor index to Tennessee's WACOG exists; and

WHEREAS, the Company and the Seller have agreed upon the terms of an index to replace Tennessee's WACOG for purposes of calculating the Monthly Energy Charge, and desire to execute this Amendment for purposes of memorializing their agreement.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein, the Company and the Seller agree as follows:

1. Unless otherwise defined herein, capitalized terms shall have the same meaning given to them in the Agreement.

2. For the purposes of determining the Monthly Energy Charge as defined in Section 3 of Appendix B of the Agreement, the first ~~paragraph~~ sentence of said section shall be deleted in its entirety and the following shall be substituted in place thereof: GAK JJK

The Monthly Energy Charge shall be equal to the product of (i) the Delivered Energy and (ii) the Kilowatthour Charge,

where the Kilowatthour Charge is equal to the product of (i) one and thirty-six hundredths cents per kilowatthour ($0.0136/kWh) and (ii) an index factor represented by the quantity M/N,

where M shall be equal to the monthly weighted average sum of the following three fuel components, each expressed in U.S. dollars per MMBtu:

(a) 50% weighting for the monthly average of the daily quotes during the Billing Period for No. 6 residual 2.2% sulfur fuel oil as listed in Platt's Oilgram under the heading "Estimated New York Harbor Spot Price," using the low cargo quotation, and assuming 6.3 MMBtu per barrel; and

(b) 40% weighting for the average of the T2 spot price for each of the twelve (12) months immediately preceding the Billing Period, where the T2 spot price for any month shall be equal to the arithmetic average of the following six indices for such month: the Louisiana & Offshore (zone 1) and Texas (zone 0) indices for Tennessee and the East Louisiana, West Louisiana, East Texas and South Texas indices for the Texas Eastern Transmission Corporation, or their successor indices, each as published in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, by reference to the table entitled "Prices of Spot Gas Delivered to Pipelines...," provided that at least four of the six indices, or their successor indices, are so published for any month, and if at least four of the six indices are not so published for any month, the parties shall determine mutually acceptable substitute indices to use for the calculation of the T2 spot price; and

(c) 10% weighting for New England Power Company's weighted average delivered cost of coal as reported in the most recently submitted FERC Form 423 for New England Power Company from time to time, and

where N is $1.61/MMBtu.

3. The Company shall submit this Amendment to the Massachusetts Department of Public Utilities for approval. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

4. All other terms and conditions of said Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

CAMBRIDGE ELECTRIC LIGHT COMPANY

By: James J. Keane

Title: Vice President
Power Supply & Transmission

ALTRESCO PITTSFIELD, L.P.
BY JMC ALTRESCO, INC.
ITS GENERAL PARTNER

By: _____

Vice President

Title: _____

SECOND AMENDMENT TO POWER PURCHASE AGREEMENT
BETWEEN CAMBRIDGE ELECTRIC COMPANY AND PITTSFIELD GENERATING COMPANY, L.P.
DATED FEBRUARY 20, 1992

Second Amendment, dated as of November 21, 1996 to the Power Purchase Agreement dated February 20, 1992, as amended (herein referred to as the "Agreement") between Cambridge Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company") and Pittsfield Generating Company, L.P., formerly known as Altresco Pittsfield, L.P., a Delaware limited partnership with a place of business at One Bowdoin Square, Boston, Massachusetts (the "Seller"). (Unless otherwise stated, all capitalized terms herein are as defined in the Agreement.)

Recitals

(a) This Second Amendment modifies certain terms of the Agreement. The Agreement provides for the sale by the Seller and the purchase by the Company of a 17.2 percent entitlement of the electric capacity and related energy produced by the Unit.

(b) Article 4.1 of the Agreement states in pertinent part: "The unit shall be subject to Economic Dispatch at the direction of the Company or NEPOOL."

(c) Article 6.1 of the Agreement states in pertinent part: "The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electricity at or near the Design Capacity on a continuous twenty-four (24) hour basis for the full term of this Agreement."

(d) Article 6.3 of the Agreement states in pertinent part: "The Seller may from time-to-time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance on the Unit."

Accordingly, the Seller and Company, each in consideration of the mutual covenants set forth herein, hereby agree as follows:

SECTION ONE: AMENDMENT TO SECTION 6 of the AGREEMENT

Section 6 of the Agreement shall be amended by adding the following provision:

6.4 Short-term Power Purchases. Seller and Company agree that, from time to time, they may agree to allow and accommodate the short-term purchase by Company of electricity from other market sources in replacement of the purchase of electricity that would otherwise occur pursuant to the Agreement, and that the terms and conditions of such arrangements shall be negotiated on a case-by-case basis and agreed to in writing, but that the Agreement shall otherwise remain in full force and effect.

SECTION TWO: NO OTHER AMENDMENTS OR MODIFICATIONS

All other terms and conditions of the Agreement not specifically amended herein shall remain in full force and effect.

IN WITNESS WHEREOF, the Seller and the Company have caused this Second Amendment to be duly executed as the day and year Second written above.

CAMBRIDGE ELECTRIC COMPANY

By: James J. Keane

Its: Vice President - Power Supply & Transmission

PITTSFIELD GENERATING COMPANY, L.P.

By: George J. Trumbull

Its: Vice President

CAMBRIDGE ELECTRIC LIGHT COMPANY

Year	Transition Base Case Revenues	Transition Pittsfield Buyout Revenues	Customer Savings
Col.A	Col.B	Col.C	Col.E
2004	$ 5.822	$ 5.822	$ -
2005	20.631	23.414	$ (2.783)
2006	18.753	10.896	$ 7.857
2007	15.669	13.794	$ 1.875
2008	8.084	11.426	$ (3.342)
2009	1.258	1.258	$ -
2010	2.685	2.685	$ -
2011	1.080	1.080	$ -
2012	0.973	0.973	$ -
2013	0.876	0.876	$ -
2014	0.892	0.892	$ -
2015	0.891	0.891	$ -
2016	0.685	0.685	$ -
2017	0.750	0.750	$ -
2018	0.763	0.763	$ -
2019	0.752	0.752	$ -
2020	0.793	0.793	$ -
2021	0.998	0.998	$ -
2022	0.075	0.075	$ -
2023	0.101	0.101	$ -
2024	0.101	0.101	$ -
2025	0.066	0.066	$ -
2026	0.086	0.086	$ -
Total	$ 82.784	$ 79.177	$ 3.607
NPV	$ 61.649	$ 58.673	$ 2.976
Discount Rate	7.720%		

Discounted at Cambridge After Tax Discount Rate
used in the Company's Restructuring Filing

Sources:
Col: B from Exhibit NSTAR-CAM-GOL-3, Col.D
Col: C from Exhibit NSTAR-CAM-GOL-4, Col.D
Col: D = Col.B minus Col.D

Cambridge Electric Light Company
Transition Charge Calculation
$ in Millions

Year	GWH Delivered	Transition Charge Billed	**Revenues for Delivered GWH**	Total Fixed Component	Total Variable Component	Total Other Adjustment	Prior Year Deferral	Interest on Deferral	**Expenses**	(Over) Under Collection
Col. A	Col. B	Col. C	**Col. D**	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2002										$ 1.100
2003	1,639.566	0.248	**$ 4.067**	$ (2.520)	$ 3.550	$ (2.228)	$ 1.100	$ 0.042	**$ (0.056)**	(4.123)
2004	**1,651.019**	**0.353**	**5.822**	**(2.421)**	**13.948**	**0.327**	**(4.123)**	**(0.109)**	**7.622**	**1.800**
2005	1,684.039	1.225	**20.631**	(2.291)	20.744	0.348	1.800	0.030	**20.631**	-
2006	1,717.720	1.092	**18.753**	(2.160)	20.612	0.301	-	-	**18.753**	-
2007	1,752.074	0.894	**15.669**	(2.028)	17.384	0.313	-	-	**15.669**	-
2008	1,787.115	0.452	**8.084**	(1.895)	9.658	0.321	-	-	**8.084**	-
2009	1,822.857	0.069	**1.258**	(1.773)	2.760	0.271	-	-	**1.258**	-
2010	1,859.314	0.144	**2.685**	-	2.491	0.194	-	-	**2.685**	-
2011	1,896.500	0.057	**1.080**	-	0.882	0.198	-	-	**1.080**	-
2012	1,934.430	0.050	**0.973**	-	0.764	0.209	-	-	**0.973**	-
2013	1,973.119	0.044	**0.876**	-	0.763	0.113	-	-	**0.876**	-
2014	2,012.581	0.044	**0.892**	-	0.761	0.131	-	-	**0.892**	-
2015	2,052.833	0.043	**0.891**	-	0.763	0.128	-	-	**0.891**	-
2016	2,093.890	0.033	**0.685**	-	0.594	0.091	-	-	**0.685**	-
2017	2,135.768	0.035	**0.750**	-	0.639	0.111	-	-	**0.750**	-
2018	2,178.483	0.035	**0.763**	-	0.655	0.108	-	-	**0.763**	-
2019	2,222.053	0.034	**0.752**	-	0.671	0.081	-	-	**0.752**	-
2020	2,266.494	0.035	**0.793**	-	0.689	0.104	-	-	**0.793**	-
2021	2,311.824	0.043	**0.998**	-	0.895	0.103	-	-	**0.998**	-
2022	2,358.060	0.003	**0.075**	-	-	0.075	-	-	**0.075**	-
2023	2,405.221	0.004	**0.101**	-	-	0.101	-	-	**0.101**	-
2024	2,453.325	0.004	**0.101**	-	-	0.101	-	-	**0.101**	-
2025	2,502.392	0.003	**0.066**	-	-	0.066	-	-	**0.066**	-
2026	2,552.440	0.003	**0.086**	-	-	0.086	-	-	**0.086**	-

Col. B: 2003 - 12 months actual; 2004 - 5 months actual, 7 months forecast; years 2005 and beyond assumes 2% growth per annum.
Col. C: 2003 & 2004 = Col. D / Col. B; Post 2004 = Col. J / Col. B.
Col. D: 2003 per Page 2, Line 15; 2004 = Col. B * Col. C; Post 2004 = Col. J.
Col. E: Page 3, Col. H.
Col. F: Page 4, Col. M.
Col. G: Page 5, Col. K.
Col. H: Col. K prior year.
Col. I: Col. H times interest rate on customer deposits; 2002 ending balance = 3.83%; 2003 ending balance = 2.64%; Post 2003 = 1.65%.
Col. J: Sum Cols. E thru Col. I.
Col. K: 2002 per D.T.E. 02-80B (Settlement); 2003 and later = Col. J - Col. D.

Cambridge Electric Light Company
Actual 2003 Transition Revenues
$ in Millions

Line	Description	GWH	A/C #	Per Book $	Total
1	2003 Transition Billed Revenues:				
2	Residential Transition	194.744	440160	$ 0.367	
3	Commercial Transition	1,408.726	442500	4.384	
4	Industrial Transition	34.234	442430	0.116	
5	Street Light Transition	8.348	444060	0.016	
6	Total Billed Revenues	1,646.052			**$ 4.883**
7	2003 Transition Unbilled Revenues:			Value	
8	Less: Residential Transition Unbilled @ 12/31/02	(10.466)			
9	Plus: Residential Transition Unbilled @ 12/31/03	9.564	440162	$ (0.106)	
10	Less: Commercial Transition Unbilled @ 12/31/02	(73.966)			
11	Plus: Commercial Transition Unbilled @ 12/31/03	69.285	442505	(0.666)	
12	Less: Industrial Transition Unbilled @ 12/31/02	(3.518)			
13	Plus: Industrial Transition Unbilled @ 12/31/03	2.615	442435	(0.044)	
14	Total Unbilled Revenues	(6.486)			**(0.816)**
15	Total 2003 Transition Revenues	1,639.566	0.248		**$ 4.067**

Cambridge Electric Light Company
Summary of Transition Charge - Fixed Component
$ in Millions

	Cambridge Electric Light Company		Residual Value Credit				
Year	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Cambridge Generation Recovery/(Proceeds)	Amortization of Cambridge Generation Recovery/(Proceeds)	Pre-Tax Return on Canal Related Generation Recovery/(Proceeds)	Amortization of Canal Related Generation Recovery/(Proceeds)	Net Fixed Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003	$ 0.013	$ 0.024	$ (0.855)	$ (1.704)	$ -	$ 0.002	$ (2.520)
2004	0.011	0.024	(0.732)	(1.726)	-	0.002	(2.421)
2005	0.009	0.024	(0.600)	(1.726)	-	0.002	(2.291)
2006	0.007	0.024	(0.467)	(1.726)	-	0.002	(2.160)
2007	0.006	0.024	(0.334)	(1.726)	-	0.002	(2.028)
2008	0.004	0.024	(0.200)	(1.726)	0.001	0.002	(1.895)
2009	0.001	0.029	(0.067)	(1.731)	-	(0.005)	(1.773)

Note: Amounts per Exhibit CAM-JFL-2(DTE 03-118(Supp)).
Col H = Sum Cols. B through G.

Cambridge Electric Light Company
Summary of Transition Charge - Variable Component
$ in Millions

Year	Actual Nuclear Decomm	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Transmission In Support Of Remote Generating Units	Actual Power Contract Buyouts	Actual Payments in Lieu of Property Taxes	Revenue Credits & Damages, Costs, or net Recoveries	Wholesale Credits/Debits (Belmont)	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$ 4.834	$ 22.167	$ 13.926	$ 8.241	$ 0.956	$ (0.070)	$ -	$ (9.851)	$ (0.097)	$ (0.463)	$ -	$ 3.550
2004	6.128	19.951	13.185	6.766	0.963	-	-	-	-	(0.372)	0.463	13.948
2005	8.017	20.022	8.514	11.508	0.847	-	-	-	-	-	0.372	20.744
2006	7.070	20.342	7.482	12.860	0.682	-	-	-	-	-	-	20.612
2007	4.842	18.855	6.960	11.895	0.647	-	-	-	-	-	-	17.384
2008	2.340	13.921	7.243	6.678	0.640	-	-	-	-	-	-	9.658
2009	1.976	7.789	7.789	-	0.784	-	-	-	-	-	-	2.760
2010	1.712	7.872	7.872	-	0.779	-	-	-	-	-	-	2.491
2011	-	8.407	8.298	0.109	0.773	-	-	-	-	-	-	0.882
2012	-	1.045	1.049	(0.004)	0.768	-	-	-	-	-	-	0.764
2013	-	-	-	-	0.763	-	-	-	-	-	-	0.763
2014	-	-	-	-	0.761	-	-	-	-	-	-	0.761
2015	-	-	-	-	0.763	-	-	-	-	-	-	0.763
2016	-	-	-	-	0.594	-	-	-	-	-	-	0.594
2017	-	-	-	-	0.639	-	-	-	-	-	-	0.639
2018	-	-	-	-	0.655	-	-	-	-	-	-	0.655
2019	-	-	-	-	0.671	-	-	-	-	-	-	0.671
2020	-	-	-	-	0.689	-	-	-	-	-	-	0.689
2021	-	-	-	-	0.895	-	-	-	-	-	-	0.895

Col. B: Page 6, Col. H.
Col. C: 2003 - Exhibit CAM-JFL-4, Page 3, Line 5(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-CAM-GOL-5, Page 3, Line 3.
Col. D: 2003 - Exhibit CAM-JFL-4, Page 2, Line 9(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-CAM-GOL-5, Page 2, Line 7.
Col. E: Col. C - Col. D.
Col. F: Page 7, Col. J.
Col. G: Seabrook Buyout Adjustment.
Col. I: Blackstone Sale Excess Proceeds.
Col. J: Total Revenue less Transmission related revenue & allocated wholesale generation costs
Col. K: Exhibit CAM-HCL-6.
Col. L: Reversal of Prior Year Rate Design Adjustment (-Col. K(prior year)).
Col. M: Col. B + Col. E+ Col. F + Col. G + Col. H + Col. I + Col. J + Col. K + Col. L

Cambridge Electric Light Company
Summary of Transition Charge - Other Adjustments
$ in Millions

					Mitigation Incentive					
Year	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Gain on Sale of Utility Land	Other Adjustment	Hydro Quebec Transmission	Fixed Component (Page 8)	Seabrook Buydown (Page 9)	Vermont Yankee Buydown (Page 10)	Seabrook Buyout (Page 11)	Total Other Adjustments
Col. A	Col B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$ (2.498)	$ 0.408	$ -	$ (0.445)	$ 0.008	$ 0.127	$ 0.127	$ (0.004)	$ 0.049	$ (2.228)
2004		-			0.006	0.122	0.124	0.044	0.031	0.327
2005		-			0.006	0.117	0.120	0.060	0.045	0.348
2006		-			0.006	0.111	0.117	0.022	0.045	0.301
2007		-			0.006	0.105	0.114	0.063	0.025	0.313
2008		-			0.006	0.099	0.110	0.066	0.040	0.321
2009		-			-	0.093	0.106	0.029	0.043	0.271
2010		-			-		0.103	0.070	0.021	0.194
2011		-			-		0.100	0.059	0.039	0.198
2012		-			-		0.096	0.072	0.041	0.209
2013		-			-		0.093		0.020	0.113
2014		-			-		0.089		0.042	0.131
2015		-			-		0.086		0.042	0.128
2016		-			-		0.083		0.008	0.091
2017		-			-		0.079		0.032	0.111
2018		-			-		0.075		0.033	0.108
2019		-			-		0.073		0.008	0.081
2020		-			-		0.069		0.035	0.104
2021		-			-		0.065		0.038	0.103
2022		-					0.063		0.012	0.075
2023		-					0.059		0.042	0.101
2024		-					0.055		0.046	0.101
2025		-					0.051		0.015	0.066
2026		-					0.046		0.040	0.086

Col. B: Amount received from E.I.S. - November 2003.

Col. C: 2003 equals 4 percent of excess proceeds of Blackstone Sale (page 4, column I), 4 percent of Seabrook Buyout Adjustment (page 4, column G) and 2003 adjustment to actual of Column I.

Col. E: Page 12, Col. E.

Col. F: Equals 4 percent of Page 7, Col. E.

Cambridge Electric Light Company
Summary of Transition Charge - Decommissioning
$ in Millions

Year	Seabrook Unit 1	Seabrook Unit 2	Yankee Atomic	Connecticut Yankee	Maine Yankee	Vermont Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003 *	$ -	$ -	$ 0.649	$ 1.902	$ 2.283	$ -	$ 4.834
2004 **	-	-	1.110	2.749	2.269	-	6.128
2005	-	-	1.113	4.508	2.396	-	8.017
2006	-	-	0.280	4.470	2.320	-	7.070
2007	-	-	0.280	2.314	2.248	-	4.842
2008	-	-	0.280	-	2.060	-	2.340
2009	-	-	0.280	-	1.696	-	1.976
2010	-	-	0.280	-	1.432	-	1.712

* 12 months actual.
** 5 months actual, 7 months forecast.
Note: Cols. B, C, & G subject to final reconciliation of sale transaction.

Cambridge Electric Light Company
Transmission in Support of Remote Generation
$ in Millions

Year	Seabrook 1	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Line 331 Equalizer	Canal Unit 1 Transfer	Canal Section A	Canal Section B	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
2003 *	$ 0.001	$ 0.122	$ 0.734	$ (0.190)	$ 0.146	$ -	$ 0.004	$ 0.139	$ 0.956
2004 **	-	0.119	0.705	(0.148)	0.146	-	0.004	0.137	0.963
2005	-	0.119	0.778	(0.150)	-	-	0.003	0.097	0.847
2006	-	0.062	0.770	(0.150)	-	-	-	-	0.682
2007	-	0.035	0.762	(0.150)	-	-	-	-	0.647
2008	-	0.036	0.754	(0.150)	-	-	-	-	0.640
2009	-	0.037	0.747	-	-	-	-	-	0.784
2010	-	0.038	0.741	-	-	-	-	-	0.779
2011	-	0.039	0.734	-	-	-	-	-	0.773
2012	-	0.040	0.728	-	-	-	-	-	0.768
2013	-	0.041	0.722	-	-	-	-	-	0.763
2014	-	0.043	0.718	-	-	-	-	-	0.761
2015	-	0.044	0.719	-	-	-	-	-	0.763
2016	-	0.045	0.549	-	-	-	-	-	0.594
2017	-	0.047	0.592	-	-	-	-	-	0.639
2018	-	0.048	0.607	-	-	-	-	-	0.655
2019	-	0.049	0.622	-	-	-	-	-	0.671
2020	-	0.051	0.638	-	-	-	-	-	0.689
2021	-	0.053	0.842	-	-	-	-	-	0.895

* 12 months actual.

** 5 months actual, 7 months forecast.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive Summary - Fixed
$ in Millions

Line	Description	2003	2004	2005	2006	2007	2008	2009
1	Residual Value Credit (Debit):							
2	Cambridge (Exhibit 2, Page 3, Line 25) Excess Proceeds	$5.938	$5.633	$5.328	$5.023	$4.718	$4.412	$4.114
3	Cambridge (Exhibit 2, Page 4, Line 20) Blackstone	0.089	0.115	0.109	0.103	0.097	0.091	0.086
4	Canal (Exhibit 2, Page 5, Line 20) Excess Proceeds	1.573	1.535	1.497	1.459	1.421	1.383	1.345
5	Cambridge (Exhibit 2, Page 6, Line 20) Seabrook Buydown (EIS)	(0.920)	(0.897)	(0.875)	(0.853)	(0.831)	(0.809)	(0.783)
6	Cambridge (Exhibit 2, Page 7, Line 20) Seabrook Buydown (Kendall)	(3.468)	(3.290)	(3.111)	(2.933)	(2.755)	(2.577)	(2.402)
7	Total	3.212	3.096	2.948	2.799	2.650	2.500	2.360
8	Less - Owned Generation per Compliance Filing:							
9	Cambridge (Exhibit 2, Page 2, Line 21) Embedded Cost (Blackstone)	0.037	0.035	0.033	0.031	0.030	0.028	0.030
10	Net Incremental Gain on Sale of Owned Gen (L7 - L9)	3.175	3.061	2.915	2.768	2.620	2.472	2.330
11	Transition Charge Mitigation Incentive Mechanism @ 4%	$0.127	$0.122	$0.117	$0.111	$0.105	$0.099	$0.093

Cambridge Electric Light Company
Transition Charge Mitigation Incentive - Seabrook Buydown
$ in Millions

	Original Forecast			Revised Forecast				Transition		
Year	Power Contract Total Obligation	Assumed Market Value	Total Filed Case	Power Contract Total Obligation	Assumed Market Value	Total Actual	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$ 6.398	$ 2.195	$ 4.203	$ 3.225	$ 2.195	$ 1.030	$ 3.173	$ 0.127	1,639.566	0.00775
2004	6.189	2.513	3.676	3.098	2.513	0.585	3.091	0.124	1,651.019	0.00751
2005	6.310	2.372	3.938	3.304	2.372	0.932	3.006	0.120	1,684.039	0.00713
2006	6.269	2.438	3.831	3.355	2.438	0.917	2.914	0.117	1,717.720	0.00681
2007	6.058	2.802	3.256	3.220	2.802	0.418	2.838	0.114	1,752.074	0.00651
2008	6.199	2.665	3.534	3.453	2.665	0.788	2.746	0.110	1,787.115	0.00616
2009	6.172	2.667	3.505	3.513	2.667	0.846	2.659	0.106	1,822.857	0.00582
2010	5.946	3.077	2.869	3.366	3.077	0.289	2.580	0.103	1,859.314	0.00554
2011	6.119	2.878	3.241	3.626	2.878	0.748	2.493	0.100	1,896.500	0.00527
2012	6.096	2.915	3.181	3.696	2.915	0.781	2.400	0.096	1,934.430	0.00496
2013	5.866	3.284	2.582	3.538	3.284	0.254	2.328	0.093	1,973.119	0.00471
2014	6.066	3.049	3.017	3.832	3.049	0.783	2.234	0.089	2,012.581	0.00442
2015	6.060	3.129	2.931	3.915	3.129	0.786	2.145	0.086	2,052.833	0.00419
2016	5.814	3.564	2.250	3.742	3.564	0.178	2.072	0.083	2,093.890	0.00396
2017	6.054	3.316	2.738	4.072	3.316	0.756	1.982	0.079	2,135.768	0.00370
2018	6.056	3.385	2.671	4.169	3.385	0.784	1.887	0.075	2,178.483	0.00344
2019	5.803	3.820	1.983	3.981	3.820	0.161	1.822	0.073	2,222.053	0.00329
2020	6.080	3.510	2.570	4.356	3.510	0.846	1.724	0.069	2,266.494	0.00304
2021	6.108	3.569	2.539	4.477	3.569	0.908	1.631	0.065	2,311.824	0.00281
2022	5.843	4.016	1.827	4.275	4.016	0.259	1.568	0.063	2,358.060	0.00267
2023	6.181	3.695	2.486	4.711	3.695	1.016	1.470	0.059	2,405.221	0.00245
2024	6.240	3.761	2.479	4.877	3.761	1.116	1.363	0.055	2,453.325	0.00224
2025	5.847	4.234	1.613	4.577	4.234	0.343	1.270	0.051	2,502.392	0.00204
2026	6.003	3.895	2.108	4.850	3.895	0.955	1.153	0.046	2,552.440	0.00180

Col B: See DTE 98-78, Schedule 1, Page 11, Column (1).
Col C: See DTE 98-78, Schedule 1, Page 12, Column (1) times NERA Base Load Market Forecast.
Col D: Col. C - Col. D.
See DTE 99-89 for revised amounts for Cols. E and F.
Col G: Col E - Col F.
Col H: Col. C - Col. G.
Col I: Col. H Multiplied by 4%.
Col J: Page 1, Col. B.
Col K: Col. I/Col. J Multiplied by 100.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive - Vermont Yankee Buydown
$ in Millions

	Original Forecast					Revised Forecast					Transition		
Year	Nuclear Decom Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Filed Case	Nuclear Decom Costs	Power Contract Total Obligation	Assumed Market Value	Total Actual	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
2003	$0.488	$ 4.102	4.944	$ (0.842)	$(0.354)	$ -	$ 4.697	$ 4.944	$ (0.247)	$ (0.107)	$ (0.004)	1,639.566	(0.00024)
2004	0.488	4.744	4.755	(0.011)	0.477		4.133	4.755	(0.622)	1.099	0.044	1,651.019	0.00267
2005	0.488	4.829	3.701	1.128	1.616		3.816	3.701	0.115	1.501	0.060	1,684.039	0.00356
2006	0.488	4.319	4.305	0.014	0.502		4.264	4.305	(0.041)	0.543	0.022	1,717.720	0.00128
2007	0.488	4.920	3.952	0.968	1.456		3.825	3.952	(0.127)	1.583	0.063	1,752.074	0.00360
2008	0.588	5.039	4.170	0.869	1.457		3.976	4.170	(0.194)	1.651	0.066	1,787.115	0.00369
2009	0.588	4.719	4.709	0.010	0.598		4.580	4.709	(0.129)	0.727	0.029	1,822.857	0.00159
2010	0.588	5.321	4.341	0.980	1.568		4.153	4.341	(0.188)	1.756	0.070	1,859.314	0.00376
2011	0.588	5.136	4.490	0.646	1.234		4.251	4.490	(0.239)	1.473	0.059	1,896.500	0.00311
2012	0.147	2.892	1.283	1.609	1.756		1.232	1.283	(0.051)	1.807	0.072	1,934.430	0.00372

See DTE 01-94 for original amounts for Cols. B through E.

Col. F: Col. B + Col. E.

See DTE 01-94 for revised amounts for Cols. G through I.

Col. J: Col G + Col H - Col I

Col. K: Col. F - Col. J

Col. L: Col. K Multiplied by 4%.

Col. M: Page 1, Col. B.

Col. N: Col. L/Col. M Multiplied by 100.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buyout
$ in Millions

	Original Forecast						Revised Forecast				
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Transmission in Support of Remote Generation	Total Filed Case	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$0.141	$3.225	$2.195	$1.030	$0.046	$1.217	$ -	$1.217	$0.049	1,639.566	0.00299
2004	0.147	3.098	2.513	0.585	0.046	0.778		0.778	0.031	1,651.019	0.00188
2005	0.153	3.304	2.372	0.932	0.045	1.130		1.130	0.045	1,684.039	0.00267
2006	0.159	3.355	2.438	0.917	0.045	1.121		1.121	0.045	1,717.720	0.00262
2007	0.166	3.220	2.802	0.418	0.044	0.628		0.628	0.025	1,752.074	0.00143
2008	0.173	3.453	2.665	0.788	0.044	1.005		1.005	0.040	1,787.115	0.00224
2009	0.180	3.513	2.667	0.846	0.043	1.069		1.069	0.043	1,822.857	0.00236
2010	0.188	3.366	3.077	0.289	0.043	0.520		0.520	0.021	1,859.314	0.00113
2011	0.196	3.626	2.878	0.748	0.042	0.986		0.986	0.039	1,896.500	0.00206
2012	0.204	3.696	2.915	0.781	0.042	1.027		1.027	0.041	1,934.430	0.00212
2013	0.212	3.538	3.284	0.254	0.041	0.507		0.507	0.020	1,973.119	0.00101
2014	0.221	3.832	3.049	0.783	0.041	1.045		1.045	0.042	2,012.581	0.00209
2015	0.230	3.915	3.129	0.786	0.040	1.056		1.056	0.042	2,052.833	0.00205
2016	(0.004)	3.742	3.564	0.178	0.028	0.202		0.202	0.008	2,093.890	0.00038
2017	(0.003)	4.072	3.316	0.756	0.035	0.788		0.788	0.032	2,135.768	0.00150
2018	(0.003)	4.169	3.385	0.784	0.036	0.817		0.817	0.033	2,178.483	0.00151
2019	(0.003)	3.981	3.820	0.161	0.036	0.194		0.194	0.008	2,222.053	0.00036
2020	(0.003)	4.356	3.510	0.846	0.037	0.880		0.880	0.035	2,266.494	0.00154
2021	(0.002)	4.477	3.569	0.908	0.037	0.943		0.943	0.038	2,311.824	0.00164
2022	(0.002)	4.275	4.016	0.259	0.037	0.294		0.294	0.012	2,358.060	0.00051
2023	(0.002)	4.711	3.695	1.016	0.038	1.052		1.052	0.042	2,405.221	0.00175
2024	(0.002)	4.877	3.761	1.116	0.039	1.153		1.153	0.046	2,453.325	0.00188
2025	(0.001)	4.577	4.234	0.343	0.039	0.381		0.381	0.015	2,502.392	0.00060
2026	(0.001)	4.850	3.895	0.955	0.040	0.994		0.994	0.040	2,552.440	0.00157

Column Notes:

Col. B: See DTE 01-79, Exhibit CAM-BKR-1, Page 6, Columns B & C.
Col. C: See Page 9, Column E.
Col. D: See Page 9, Column F.
Col. E: Col. C - Col. D.
Col. F: See DTE 99-90, Schedule 1, Page 7, Column (1).
Col. G: Col. B + Col. E + Col. F.
Col. H: Estimated Buyout Amount per DTE 02-34.
Col. I: Col. G - Col. H.
Col. J: Col. I Multiplied by 4%.
Col. K: See Page 1, Col. B.
Col. L: Col. J/Col. K Multiplied by 100.

Cambridge Electric Light Company
Blackstone Station Revenue Credit
$ in Millions

Year	Blackstone Station Costs	Blackstone Station Revenues	Variance	Revenue Credit Applied
Col. A	Col. B	Col. C	Col. D	Col. E
2003	$ 0.040	$ 0.485	$ (0.445)	$ (0.445)

Note:
Revenues - Lease of Blackstone by Harvard.
Costs - 2003 property insurance, A & G salaries, water bill,
and personal property taxes.
Blackstone Sale effective April 8, 2003.

Cambridge Electric Light Company
Power Contract Obligations
Annual Obligations in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	Total
Col. A	Col. B	Col. C	Col. D
Jan - May			
Jun - Sep			
Oct - Dec			
2004			
Jan - Feb			
Mar - Dec			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

REDACTED

Note:
Updated from CAM-JFL-3 (supp) in D.T.E. 03-118
with latest forecast from CEA

Cambridge Electric Light Company
Power Contract Obligations
Annual Market in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E
Jan - May				
Jun - Sep				
Oct - Dec				
2004				
Jan - Feb				
Mar - Dec				
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				

REDACTED

Note:
Cols B and C are updated from CAM-JFL-3 (supp) in D.T.E. 03-118
with latest forecast from CEA
Col.D = Col.E minus Cols. B & C
Col.E for Jan 2004 through Feb 2005 (Standard Offer period) is equal
to the transfer price from NSTAR-GOL-5 & 7 (page 1, line 7)
Col.E for March 2005 onwards = Col.B + Col.C

Cambridge Electric Light Company
Power Contract Obligations
Annual Above Market in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E
Jan - May				
Jun - Sep				
Oct - Dec				
2004				
Jan - Feb				
Mar - Dec				
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				

REDACTED

Note:
Annual above Market = Annual Obligation (p.13) minus Annual Market (p.14)

Cambridge Electric Light Company
Transition Charge Calculation
$ in Millions

Year	GWH Delivered	Transition Charge Billed	**Revenues for Delivered GWH**	Total Fixed Component	Total Variable Component	Total Other Adjustment	Prior Year Deferral	Interest on Deferral	**Expenses**	(Over) Under Collection
Col. A	Col. B	Col. C	**Col. D**	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2002										$ 1.100
2003	1,639.566	0.248	**$ 4.067**	$ (2.520)	$ 3.550	$ (2.228)	$ 1.100	$ 0.042	**$ (0.056)**	(4.123)
2004	**1,651.019**	**0.353**	**5.822**	**(2.421)**	**13.709**	**0.472**	**(4.123)**	**(0.109)**	**7.528**	**1.706**
2005	1,684.039	1.390	**23.414**	(2.291)	23.623	0.348	1.706	0.028	**23.414**	-
2006	1,717.720	0.634	**10.896**	(2.160)	12.755	0.301	-	-	**10.896**	-
2007	1,752.074	0.787	**13.794**	(2.028)	15.509	0.313	-	-	**13.794**	-
2008	1,787.115	0.639	**11.426**	(1.895)	13.000	0.321	-	-	**11.426**	-
2009	1,822.857	0.069	**1.258**	(1.773)	2.760	0.271	-	-	**1.258**	-
2010	1,859.314	0.144	**2.685**	-	2.491	0.194	-	-	**2.685**	-
2011	1,896.500	0.057	**1.080**	-	0.882	0.198	-	-	**1.080**	-
2012	1,934.430	0.050	**0.973**	-	0.764	0.209	-	-	**0.973**	-
2013	1,973.119	0.044	**0.876**	-	0.763	0.113	-	-	**0.876**	-
2014	2,012.581	0.044	**0.892**	-	0.761	0.131	-	-	**0.892**	-
2015	2,052.833	0.043	**0.891**	-	0.763	0.128	-	-	**0.891**	-
2016	2,093.890	0.033	**0.685**	-	0.594	0.091	-	-	**0.685**	-
2017	2,135.768	0.035	**0.750**	-	0.639	0.111	-	-	**0.750**	-
2018	2,178.483	0.035	**0.763**	-	0.655	0.108	-	-	**0.763**	-
2019	2,222.053	0.034	**0.752**	-	0.671	0.081	-	-	**0.752**	-
2020	2,266.494	0.035	**0.793**	-	0.689	0.104	-	-	**0.793**	-
2021	2,311.824	0.043	**0.998**	-	0.895	0.103	-	-	**0.998**	-
2022	2,358.060	0.003	**0.075**	-	-	0.075	-	-	**0.075**	-
2023	2,405.221	0.004	**0.101**	-	-	0.101	-	-	**0.101**	-
2024	2,453.325	0.004	**0.101**	-	-	0.101	-	-	**0.101**	-
2025	2,502.392	0.003	**0.066**	-	-	0.066	-	-	**0.066**	-
2026	2,552.440	0.003	**0.086**	-	-	0.086	-	-	**0.086**	-

Col. B: 2003 - 12 months actual; 2004 - 5 months actual, 7 months forecast; years 2005 and beyond assumes 2% growth per annum.
Col. C: 2003 & 2004 = Col. D / Col. B; Post 2004 = Col. J / Col. B.
Col. D: 2003 per Page 2, Line 15; 2004 = Col. B * Col. C; Post 2004 = Col. J.
Col. E: Page 3, Col. H.
Col. F: Page 4, Col. M.
Col. G: Page 5, Col. K.
Col. H: Col. K prior year.
Col. I: Col. H times interest rate on customer deposits; 2002 ending balance = 3.83%; 2003 ending balance = 2.64%; Post 2003 = 1.65%.
Col. J: Sum Cols. E thru Col. I.
Col. K: 2002 per D.T.E. 02-80B (Settlement); 2003 and later = Col. J - Col. D.

Cambridge Electric Light Company
Actual 2003 Transition Revenues
$ in Millions

Line	Description	GWH	A/C #	Per Book $	Total
1	2003 Transition Billed Revenues:				
2	Residential Transition	194.744	440160	$ 0.367	
3	Commercial Transition	1,408.726	442500	4.384	
4	Industrial Transition	34.234	442430	0.116	
5	Street Light Transition	8.348	444060	0.016	
6	Total Billed Revenues	1,646.052			**$ 4.883**
7	2003 Transition Unbilled Revenues:			Value	
8	Less: Residential Transition Unbilled @ 12/31/02	(10.466)			
9	Plus: Residential Transition Unbilled @ 12/31/03	9.564	440162	$ (0.106)	
10	Less: Commercial Transition Unbilled @ 12/31/02	(73.966)			
11	Plus: Commercial Transition Unbilled @ 12/31/03	69.285	442505	(0.666)	
12	Less: Industrial Transition Unbilled @ 12/31/02	(3.518)			
13	Plus: Industrial Transition Unbilled @ 12/31/03	2.615	442435	(0.044)	
14	Total Unbilled Revenues	(6.486)			**(0.816)**
15	Total 2003 Transition Revenues	1,639.566	0.248		**$ 4.067**

Cambridge Electric Light Company
Summary of Transition Charge - Fixed Component
$ in Millions

	Cambridge Electric Light Company		Residual Value Credit				
Year	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Cambridge Generation Recovery/(Proceeds)	Amortization of Cambridge Generation Recovery/(Proceeds)	Pre-Tax Return on Canal Related Generation Recovery/(Proceeds)	Amortization of Canal Related Generation Recovery/(Proceeds)	Net Fixed Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003	$ 0.013	$ 0.024	$ (0.855)	$ (1.704)	$ -	$ 0.002	$ (2.520)
2004	0.011	0.024	(0.732)	(1.726)	-	0.002	(2.421)
2005	0.009	0.024	(0.600)	(1.726)	-	0.002	(2.291)
2006	0.007	0.024	(0.467)	(1.726)	-	0.002	(2.160)
2007	0.006	0.024	(0.334)	(1.726)	-	0.002	(2.028)
2008	0.004	0.024	(0.200)	(1.726)	0.001	0.002	(1.895)
2009	0.001	0.029	(0.067)	(1.731)	-	(0.005)	(1.773)

Note: Amounts per Exhibit CAM-JFL-2(DTE 03-118(Supp)).
Col H = Sum Cols. B through G.

Cambridge Electric Light Company
Summary of Transition Charge - Variable Component
$ in Millions

Year	Actual Nuclear Decomm	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Transmission In Support Of Remote Generating Units	Actual Power Contract Buyouts	Actual Payments in Lieu of Property Taxes	Revenue Credits & Damages, Costs, or net Recoveries	Wholesale Credits/Debits (Belmont)	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$ 4.834	$ 22.167	$ 13.926	$ 8.241	$ 0.956	$ (0.070)	$ -	$ (9.851)	$ (0.097)	$ (0.463)	$ -	$ 3.550
2004	6.128	18.225	11.698	6.527	0.963	-	-	-	-	(0.372)	0.463	13.709
2005	8.017	18.880	4.493	14.387	0.847	-	-	-	-	-	0.372	23.623
2006	7.070	9.018	4.015	5.003	0.682	-	-	-	-	-	-	12.755
2007	4.842	13.547	3.527	10.020	0.647	-	-	-	-	-	-	15.509
2008	2.340	13.670	3.650	10.020	0.640	-	-	-	-	-	-	13.000
2009	1.976	4.067	4.067	-	0.784	-	-	-	-	-	-	2.760
2010	1.712	3.950	3.950	-	0.779	-	-	-	-	-	-	2.491
2011	-	4.264	4.155	0.109	0.773	-	-	-	-	-	-	0.882
2012	-	1.045	1.049	(0.004)	0.768	-	-	-	-	-	-	0.764
2013	-	-	-	-	0.763	-	-	-	-	-	-	0.763
2014	-	-	-	-	0.761	-	-	-	-	-	-	0.761
2015	-	-	-	-	0.763	-	-	-	-	-	-	0.763
2016	-	-	-	-	0.594	-	-	-	-	-	-	0.594
2017	-	-	-	-	0.639	-	-	-	-	-	-	0.639
2018	-	-	-	-	0.655	-	-	-	-	-	-	0.655
2019	-	-	-	-	0.671	-	-	-	-	-	-	0.671
2020	-	-	-	-	0.689	-	-	-	-	-	-	0.689
2021	-	-	-	-	0.895	-	-	-	-	-	-	0.895

Col. B: Page 6, Col. H.
Col. C: 2003 - Exhibit CAM-JFL-4, Page 3, Line 5(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-CAM-GOL-6, Page 3, Line 3.
Col. D: 2003 - Exhibit CAM-JFL-4, Page 2, Line 9(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-CAM-GOL-6, Page 2, Line 7.
Col. E: Col. C - Col. D.
Col. F: Page 7, Col. J.
Col. G: Seabrook Buyout Adjustment.
Col. I: Blackstone Sale Excess Proceeds.
Col. J: Total Revenue less Transmission related revenue & allocated wholesale generation costs
Col. K: Exhibit CAM-HCL-6.
Col. L: Reversal of Prior Year Rate Design Adjustment (-Col. K(prior year)).
Col. M: Col. B + Col. E+ Col. F + Col. G + Col. H + Col. I + Col. J + Col. K + Col. L

Cambridge Electric Light Company
Summary of Transition Charge - Other Adjustments
$ in Millions

					Mitigation Incentive					
Year	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Gain on Sale of Utility Land	Other Adjustment	Hydro Quebec Transmission	Fixed Component (Page 8)	Seabrook Buydown (Page 9)	Vermont Yankee Buydown (Page 10)	Seabrook Buyout (Page 11)	Total Other Adjustments
Col. A	Col B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$ (2.498)	$ 0.408	$ -	$ (0.445)	$ 0.008	$ 0.127	$ 0.127	$ (0.004)	$ 0.049	$ (2.228)
2004		0.145			0.006	0.122	0.124	0.044	0.031	0.472
2005		-			0.006	0.117	0.120	0.060	0.045	0.348
2006		-			0.006	0.111	0.117	0.022	0.045	0.301
2007		-			0.006	0.105	0.114	0.063	0.025	0.313
2008		-			0.006	0.099	0.110	0.066	0.040	0.321
2009		-			-	0.093	0.106	0.029	0.043	0.271
2010		-			-		0.103	0.070	0.021	0.194
2011		-			-		0.100	0.059	0.039	0.198
2012		-			-		0.096	0.072	0.041	0.209
2013		-			-		0.093		0.020	0.113
2014		-			-		0.089		0.042	0.131
2015		-			-		0.086		0.042	0.128
2016		-			-		0.083		0.008	0.091
2017		-			-		0.079		0.032	0.111
2018		-			-		0.075		0.033	0.108
2019		-			-		0.073		0.008	0.081
2020		-			-		0.069		0.035	0.104
2021		-			-		0.065		0.038	0.103
2022		-					0.063		0.012	0.075
2023		-					0.059		0.042	0.101
2024		-					0.055		0.046	0.101
2025		-					0.051		0.015	0.066
2026		-					0.046		0.040	0.086

Col. B: Amount received from E.I.S. - November 2003.

Col. C: 2003 equals 4 percent of excess proceeds of Blackstone Sale (page 4, column I), 4 percent of Seabrook Buyout Adjustment (page 4, column G) and 2003 adjustment to actual of Column I. 2004 equals the NPV of 4% of the Altresco-Pittsfield savings (page 16, column G).

Col. E: Page 12, Col. E.

Col. F: Equals 4 percent of Page 7, Col. E.

Cambridge Electric Light Company
Summary of Transition Charge - Decommissioning
$ in Millions

Year	Seabrook Unit 1	Seabrook Unit 2	Yankee Atomic	Connecticut Yankee	Maine Yankee	Vermont Yankee	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003 *	$ -	$ -	$ 0.649	$ 1.902	$ 2.283	$ -	$ 4.834
2004 **	-	-	1.110	2.749	2.269	-	6.128
2005	-	-	1.113	4.508	2.396	-	8.017
2006	-	-	0.280	4.470	2.320	-	7.070
2007	-	-	0.280	2.314	2.248	-	4.842
2008	-	-	0.280	-	2.060	-	2.340
2009	-	-	0.280	-	1.696	-	1.976
2010	-	-	0.280	-	1.432	-	1.712

* 12 months actual.
** 5 months actual, 7 months forecast.
Note: Cols. B, C, & G subject to final reconciliation of sale transaction.

Cambridge Electric Light Company
Transmission in Support of Remote Generation
$ in Millions

Year	Seabrook 1	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Line 331 Equalizer	Canal Unit 1 Transfer	Canal Section A	Canal Section B	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J
2003 *	$ 0.001	$ 0.122	$ 0.734	$ (0.190)	$ 0.146	$ -	$ 0.004	$ 0.139	$ 0.956
2004 **	-	0.119	0.705	(0.148)	0.146	-	0.004	0.137	0.963
2005	-	0.119	0.778	(0.150)	-	-	0.003	0.097	0.847
2006	-	0.062	0.770	(0.150)	-	-	-	-	0.682
2007	-	0.035	0.762	(0.150)	-	-	-	-	0.647
2008	-	0.036	0.754	(0.150)	-	-	-	-	0.640
2009	-	0.037	0.747	-	-	-	-	-	0.784
2010	-	0.038	0.741	-	-	-	-	-	0.779
2011	-	0.039	0.734	-	-	-	-	-	0.773
2012	-	0.040	0.728	-	-	-	-	-	0.768
2013	-	0.041	0.722	-	-	-	-	-	0.763
2014	-	0.043	0.718	-	-	-	-	-	0.761
2015	-	0.044	0.719	-	-	-	-	-	0.763
2016	-	0.045	0.549	-	-	-	-	-	0.594
2017	-	0.047	0.592	-	-	-	-	-	0.639
2018	-	0.048	0.607	-	-	-	-	-	0.655
2019	-	0.049	0.622	-	-	-	-	-	0.671
2020	-	0.051	0.638	-	-	-	-	-	0.689
2021	-	0.053	0.842	-	-	-	-	-	0.895

* 12 months actual.

** 5 months actual, 7 months forecast.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive Summary - Fixed
$ in Millions

Line	Description	2003	2004	2005	2006	2007	2008	2009
1	Residual Value Credit (Debit):							
2	Cambridge (Exhibit 2, Page 3, Line 25) Excess Proceeds	$5.938	$5.633	$5.328	$5.023	$4.718	$4.412	$4.114
3	Cambridge (Exhibit 2, Page 4, Line 20) Blackstone	0.089	0.115	0.109	0.103	0.097	0.091	0.086
4	Canal (Exhibit 2, Page 5, Line 20) Excess Proceeds	1.573	1.535	1.497	1.459	1.421	1.383	1.345
5	Cambridge (Exhibit 2, Page 6, Line 20) Seabrook Buydown (EIS)	(0.920)	(0.897)	(0.875)	(0.853)	(0.831)	(0.809)	(0.783)
6	Cambridge (Exhibit 2, Page 7, Line 20) Seabrook Buydown (Kendall)	(3.468)	(3.290)	(3.111)	(2.933)	(2.755)	(2.577)	(2.402)
7	Total	3.212	3.096	2.948	2.799	2.650	2.500	2.360
8	Less - Owned Generation per Compliance Filing:							
9	Cambridge (Exhibit 2, Page 2, Line 21) Embedded Cost (Blackstone)	0.037	0.035	0.033	0.031	0.030	0.028	0.030
10	Net Incremental Gain on Sale of Owned Gen (L7 - L9)	3.175	3.061	2.915	2.768	2.620	2.472	2.330
11	Transition Charge Mitigation Incentive Mechanism @ 4%	$0.127	$0.122	$0.117	$0.111	$0.105	$0.099	$0.093

Cambridge Electric Light Company
Transition Charge Mitigation Incentive - Seabrook Buydown
$ in Millions

	Original Forecast			Revised Forecast				Transition		
Year	Power Contract Total Obligation	Assumed Market Value	Total Filed Case	Power Contract Total Obligation	Assumed Market Value	Total Actual	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$ 6.398	$ 2.195	$ 4.203	$ 3.225	$ 2.195	$ 1.030	$ 3.173	$ 0.127	1,639.566	0.00775
2004	6.189	2.513	3.676	3.098	2.513	0.585	3.091	0.124	1,651.019	0.00751
2005	6.310	2.372	3.938	3.304	2.372	0.932	3.006	0.120	1,684.039	0.00713
2006	6.269	2.438	3.831	3.355	2.438	0.917	2.914	0.117	1,717.720	0.00681
2007	6.058	2.802	3.256	3.220	2.802	0.418	2.838	0.114	1,752.074	0.00651
2008	6.199	2.665	3.534	3.453	2.665	0.788	2.746	0.110	1,787.115	0.00616
2009	6.172	2.667	3.505	3.513	2.667	0.846	2.659	0.106	1,822.857	0.00582
2010	5.946	3.077	2.869	3.366	3.077	0.289	2.580	0.103	1,859.314	0.00554
2011	6.119	2.878	3.241	3.626	2.878	0.748	2.493	0.100	1,896.500	0.00527
2012	6.096	2.915	3.181	3.696	2.915	0.781	2.400	0.096	1,934.430	0.00496
2013	5.866	3.284	2.582	3.538	3.284	0.254	2.328	0.093	1,973.119	0.00471
2014	6.066	3.049	3.017	3.832	3.049	0.783	2.234	0.089	2,012.581	0.00442
2015	6.060	3.129	2.931	3.915	3.129	0.786	2.145	0.086	2,052.833	0.00419
2016	5.814	3.564	2.250	3.742	3.564	0.178	2.072	0.083	2,093.890	0.00396
2017	6.054	3.316	2.738	4.072	3.316	0.756	1.982	0.079	2,135.768	0.00370
2018	6.056	3.385	2.671	4.169	3.385	0.784	1.887	0.075	2,178.483	0.00344
2019	5.803	3.820	1.983	3.981	3.820	0.161	1.822	0.073	2,222.053	0.00329
2020	6.080	3.510	2.570	4.356	3.510	0.846	1.724	0.069	2,266.494	0.00304
2021	6.108	3.569	2.539	4.477	3.569	0.908	1.631	0.065	2,311.824	0.00281
2022	5.843	4.016	1.827	4.275	4.016	0.259	1.568	0.063	2,358.060	0.00267
2023	6.181	3.695	2.486	4.711	3.695	1.016	1.470	0.059	2,405.221	0.00245
2024	6.240	3.761	2.479	4.877	3.761	1.116	1.363	0.055	2,453.325	0.00224
2025	5.847	4.234	1.613	4.577	4.234	0.343	1.270	0.051	2,502.392	0.00204
2026	6.003	3.895	2.108	4.850	3.895	0.955	1.153	0.046	2,552.440	0.00180

Col B: See DTE 98-78, Schedule 1, Page 11, Column (1).
Col C: See DTE 98-78, Schedule 1, Page 12, Column (1) times NERA Base Load Market Forecast.
Col D: Col. C - Col. D.
See DTE 99-89 for revised amounts for Cols. E and F.
Col G: Col E - Col F.
Col H: Col. C - Col. G.
Col I: Col. H Multiplied by 4%.
Col J: Page 1, Col. B.
Col K: Col. I/Col. J Multiplied by 100.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive - Vermont Yankee Buydown
$ in Millions

	Original Forecast					Revised Forecast					Transition		
Year	Nuclear Decom Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Filed Case	Nuclear Decom Costs	Power Contract Total Obligation	Assumed Market Value	Total Actual	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
2003	$0.488	$ 4.102	4.944	$ (0.842)	$(0.354)	$ -	$ 4.697	$ 4.944	$ (0.247)	$ (0.107)	$ (0.004)	1,639.566	(0.00024)
2004	0.488	4.744	4.755	(0.011)	0.477		4.133	4.755	(0.622)	1.099	0.044	1,651.019	0.00267
2005	0.488	4.829	3.701	1.128	1.616		3.816	3.701	0.115	1.501	0.060	1,684.039	0.00356
2006	0.488	4.319	4.305	0.014	0.502		4.264	4.305	(0.041)	0.543	0.022	1,717.720	0.00128
2007	0.488	4.920	3.952	0.968	1.456		3.825	3.952	(0.127)	1.583	0.063	1,752.074	0.00360
2008	0.588	5.039	4.170	0.869	1.457		3.976	4.170	(0.194)	1.651	0.066	1,787.115	0.00369
2009	0.588	4.719	4.709	0.010	0.598		4.580	4.709	(0.129)	0.727	0.029	1,822.857	0.00159
2010	0.588	5.321	4.341	0.980	1.568		4.153	4.341	(0.188)	1.756	0.070	1,859.314	0.00376
2011	0.588	5.136	4.490	0.646	1.234		4.251	4.490	(0.239)	1.473	0.059	1,896.500	0.00311
2012	0.147	2.892	1.283	1.609	1.756		1.232	1.283	(0.051)	1.807	0.072	1,934.430	0.00372

See DTE 01-94 for original amounts for Cols. B through E.

Col. F: Col. B + Col. E.

See DTE 01-94 for revised amounts for Cols. G through I.

Col. J: Col G + Col H - Col I

Col. K: Col. F - Col. J

Col. L: Col. K Multiplied by 4%.

Col. M: Page 1, Col. B.

Col. N: Col. L/Col. M Multiplied by 100.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buyout
$ in Millions

	Original Forecast						Revised Forecast				
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Transmission in Support of Remote Generation	Total Filed Case	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$0.141	$3.225	$2.195	$1.030	$0.046	$1.217	$0.000	$1.217	$0.049	1,639.566	0.00299
2004	0.147	3.098	2.513	0.585	0.046	0.778		0.778	0.031	1,651.019	0.00188
2005	0.153	3.304	2.372	0.932	0.045	1.130		1.130	0.045	1,684.039	0.00267
2006	0.159	3.355	2.438	0.917	0.045	1.121		1.121	0.045	1,717.720	0.00262
2007	0.166	3.220	2.802	0.418	0.044	0.628		0.628	0.025	1,752.074	0.00143
2008	0.173	3.453	2.665	0.788	0.044	1.005		1.005	0.040	1,787.115	0.00224
2009	0.180	3.513	2.667	0.846	0.043	1.069		1.069	0.043	1,822.857	0.00236
2010	0.188	3.366	3.077	0.289	0.043	0.520		0.520	0.021	1,859.314	0.00113
2011	0.196	3.626	2.878	0.748	0.042	0.986		0.986	0.039	1,896.500	0.00206
2012	0.204	3.696	2.915	0.781	0.042	1.027		1.027	0.041	1,934.430	0.00212
2013	0.212	3.538	3.284	0.254	0.041	0.507		0.507	0.020	1,973.119	0.00101
2014	0.221	3.832	3.049	0.783	0.041	1.045		1.045	0.042	2,012.581	0.00209
2015	0.230	3.915	3.129	0.786	0.040	1.056		1.056	0.042	2,052.833	0.00205
2016	(0.004)	3.742	3.564	0.178	0.028	0.202		0.202	0.008	2,093.890	0.00038
2017	(0.003)	4.072	3.316	0.756	0.035	0.788		0.788	0.032	2,135.768	0.00150
2018	(0.003)	4.169	3.385	0.784	0.036	0.817		0.817	0.033	2,178.483	0.00151
2019	(0.003)	3.981	3.820	0.161	0.036	0.194		0.194	0.008	2,222.053	0.00036
2020	(0.003)	4.356	3.510	0.846	0.037	0.880		0.880	0.035	2,266.494	0.00154
2021	(0.002)	4.477	3.569	0.908	0.037	0.943		0.943	0.038	2,311.824	0.00164
2022	(0.002)	4.275	4.016	0.259	0.037	0.294		0.294	0.012	2,358.060	0.00051
2023	(0.002)	4.711	3.695	1.016	0.038	1.052		1.052	0.042	2,405.221	0.00175
2024	(0.002)	4.877	3.761	1.116	0.039	1.153		1.153	0.046	2,453.325	0.00188
2025	(0.001)	4.577	4.234	0.343	0.039	0.381		0.381	0.015	2,502.392	0.00060
2026	(0.001)	4.850	3.895	0.955	0.040	0.994		0.994	0.040	2,552.440	0.00157

Column Notes:

Col. B: See DTE 01-79, Exhibit CAM-BKR-1, Page 6, Columns B & C.
Col. C: See Page 9, Column E.
Col. D: See Page 9, Column F.
Col. E: Col. C - Col. D.
Col. F: See DTE 99-90, Schedule 1, Page 7, Column (1).
Col. G: Col. B + Col. E + Col. F.
Col. H: Estimated Buyout Amount per DTE 02-34.
Col. I: Col. G - Col. H.
Col. J: Col. I Multiplied by 4%.
Col. K: See Page 1, Col. B.
Col. L: Col. J/Col. K Multiplied by 100.

Cambridge Electric Light Company
Blackstone Station Revenue Credit
$ in Millions

Year	Blackstone Station Costs	Blackstone Station Revenues	Variance	Revenue Credit Applied
Col. A	Col. B	Col. C	Col. D	Col. E
2003	$ 0.040	$ 0.485	$ (0.445)	$ (0.445)

Note:
Revenues - Lease of Blackstone by Harvard.
Costs - 2003 property insurance, A & G salaries, water bill,
and personal property taxes.
Blackstone Sale effective April 8, 2003.

Cambridge Electric Light Company
Power Contract Obligations
Annual Obligations in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	Total
Col. A	Col. B	Col. C	Col. D
Jan - May			
Jun - Sep			
Oct - Dec			
2004			
Jan - Feb	REDACTED		
Mar - Dec			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			

Note:
Updated from CAM-JFL-3 (supp) in D.T.E. 03-118
with latest forecast from CEA adjusted for the buyout
of Altresco-Pittsfield.
Differences from NSTAR-CAM-GOL-3 indicated by shading.

Cambridge Electric Light Company
Power Contract Obligations
Annual Market in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E
Jan - May				
Jun - Sep				
Oct - Dec				
2004				
Jan - Feb				
Mar - Dec				
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				

REDACTED

Note:
Cols B and C are updated from CAM-JFL-3 (supp) in D.T.E. 03-118
with latest forecast from CEA.
Col.D = Col.E minus Cols. B & C
Col.E for Jan 2004 through Feb 2005 (Standard Offer period) is equal
to the transfer price from NSTAR-GOL-6 & 8 (page 1, line 7)
Col.E for March 2005 onwards = Col.B + Col.C
Differences from NSTAR-CAM-GOL-3 indicated by shading.

Cambridge Electric Light Company
Power Contract Obligations
Annual Above Market in Millions of Dollars

Year	Vermont Yankee	Altresco-Pittsfield	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E
Jan - May				
Jun - Sep				
Oct - Dec				
2004				
Jan - Feb				
Mar - Dec				
2005				
2006				
2007				
2008				
2009				
2010				
2011				
2012				

REDACTED

Note:
Annual above Market = Annual Obligation (p.13) minus Annual Market (p.14)
Differences from NSTAR-CAM-GOL-3 indicated by shading.

Cambridge Electric Light Company
Transition Charge Mitigation Incentive Mechanism - Altresco-Pittsfield Buyout
$ in Millions

	Original Forecast			Revised Forecast				
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								

REDACTED

Column Notes:

Col. B: See Exhibit NSTAR-CAM-GOL-3, Page 13, Col. C.
Col. C: See Exhibit NSTAR-CAM-GOL-3, Page 14, Col. C.
Col. D: Col. B - Col. C.
Col. E: See Page 15, Col. C.
Col. F: Col. D - Col. E.
Col. G: Col. F Multiplied by 4%.
Col. H: See Page 1, Col. B.
Col. I: Col. G/Col. H Multiplied by 100.

Cambridge Electric Light Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-03	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues [page 5, line 6]		$ (4.700)	$ (4.711)	$ (4.447)	$ (4.523)	$ (4.226)	$ (4.334)	$ (4.881)	$ (5.434)	$ (4.855)	$ (4.410)	$ (4.310)	$ (4.378)	$ (55.209)	$ (22.607)	$ (19.504)	$ (13.098)
2	Standard Offer Expense [minus line 1 minus prior mo. line 5]		4.698	4.711	4.447	4.523	4.226	4.334	4.881	5.434	4.855	4.410	4.310	4.378	55.207	22.605	19.504	13.098
3	Standard Offer Deferral (Over) / Under Recovery		(0.002)	-	-	-	-	-	-	-	-	-	-	-	(0.002)	(0.002)	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ 0.002**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**				
6	Standard Offer Expense Detail															-	-	-
7	NUG Purchases [line 9 minus line 8]		$ 0.209	$ 1.393	$ 0.963	$ 0.837	$ 0.887	$ 1.109	$ 0.983	$ 0.802	$ 1.596	$ 1.533	$ 1.550	$ 1.323	$ 13.185	$ 4.289	$ 4.490	$ 4.406
8	Short Term Market Transactions [page 4, line 5]		4.489	3.318	3.484	3.686	3.339	3.225	3.898	4.632	3.259	2.877	2.760	3.055	42.022	18.316	15.014	8.692
9	Standard Offer Expense [line 2]		$ 4.698	$ 4.711	$ 4.447	$ 4.523	$ 4.226	$ 4.334	$ 4.881	$ 5.434	$ 4.855	$ 4.410	$ 4.310	$ 4.378	$ 55.207	$ 22.605	$ 19.504	$ 13.098
	Annual Interest Rate		1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%				

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Jan - May	$ 4.289
Jun - Sep	$ 4.490
Oct - Dec	$ 4.406

Cambridge Electric Light Company
Monthly NUG Generation
GWH

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	VT yankee																
2	Altresco-Pittsfield Replacement Power																
3	Altresco-Pittsfield																
4	NUGs Generation																
5	Less: Assumed Line Losses @ 1.95%																
6	Net GWH Delivered																
7	Dist Co Settlement Price (line 8 / line 6)																
8	Cost of NUG Purchases (page 1, line 7)																

REDACTED

Cambridge Electric Light Company
Total NUG Cost
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Vermont Yankee																
2	Altresco - Pittsfield																
3	Total NUG Cost																

REDACTED

Cambridge Electric Light Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
	Cost																
1	Short Term SO	$ 3.312	$ 2.412	$ 2.580	$ 2.240	$ 2.268	$ 2.322	$ 3.011	$ 3.211	$ 2.331	$ 2.074	$ 2.036	$ 2.253	$ 30.050	$ 12.812	$ 10.875	$ 6.363
2	Mirant	2.024	1.638	1.651	1.707	1.592	1.542	1.668	1.778	1.559	1.440	1.365	1.472	19.436	8.612	6.547	4.277
3	Short Term SO Sales	(0.847)	(0.732)	(0.747)	(0.261)	(0.521)	(0.639)	(0.781)	(0.357)	(0.631)	(0.637)	(0.641)	(0.670)	(7.464)	(3.108)	(2.408)	(1.948)
4	Altresco-Pittsfield Replacement Power	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total ST Market Cost	$ 4.489	$ 3.318	$ 3.484	$ 3.686	$ 3.339	$ 3.225	$ 3.898	$ 4.632	$ 3.259	$ 2.877	$ 2.760	$ 3.055	$ 42.022	$ 18.316	$ 15.014	$ 8.692
6	GWH																
7	Short Term SO Sales (page 2, line 4)	(16.233)	(14.169)	(16.319)	(6.227)	(13.271)	(15.898)	(16.429)	(7.543)	(15.898)	(16.429)	(15.898)	(16.429)	(170.743)			
8																	
9	ST Sales Price/MWH						40.20	47.55	47.35	39.70	38.75	40.35	40.80				

Note:
Short term SO sales on line 3 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Cambridge Electric Light Company
Standard Offer Revenue
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues																
2	Residential	$ 0.654	$ 0.567	$ 0.463	$ 0.528	$ 0.387	$ 0.457	$ 0.556	$ 0.678	$ 0.528	$ 0.458	$ 0.481	$ 0.527	$ 6.284	$ 2.599	$ 2.219	$ 1.466
3	Commercial	3.917	4.018	3.857	3.877	3.709	3.744	4.177	4.585	4.161	3.811	3.700	3.721	47.277	19.378	16.667	11.232
4	Industrial	0.076	0.081	0.084	0.077	0.095	0.113	0.129	0.151	0.143	0.116	0.104	0.103	1.272	0.413	0.536	0.323
5	Street Light	0.053	0.045	0.043	0.041	0.035	0.020	0.019	0.020	0.023	0.025	0.025	0.027	0.376	0.217	0.082	0.077
6	Total Standard Offer Revenues	$ 4.700	$ 4.711	$ 4.447	$ 4.523	$ 4.226	$ 4.334	$ 4.881	$ 5.434	$ 4.855	$ 4.410	$ 4.310	$ 4.378	$ 55.209	$ 22.607	$ 19.504	$ 13.098
7	Standard Offer Price						$0.05100	$0.05100	$0.05100	$0.05100	$0.05100	$0.05100	$0.05100				
8	SOSFA Price						$0.01223	$0.01223	$0.01223	$0.01223	$0.01223	$0.01223	$0.01223				
9	GWH Sales																
10	Standard Offer GWH Sales	75.516	74.539	70.349	71.709	66.882	68.536	77.212	85.947	76.775	69.754	68.171	69.235	874.625	358.995	308.470	207.160

Cambridge Electric Light Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-03	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues [page 5, line 6]		$ (4.700)	$ (4.711)	$ (4.447)	$ (4.523)	$ (4.226)	$ (4.334)	$ (4.881)	$ (5.434)	$ (4.855)	$ (4.410)	$ (4.310)	$ (4.378)	$ (55.209)	$ (22.607)	$ (19.504)	$ (13.098)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		4.698	4.711	4.447	4.523	4.226	4.334	4.881	5.434	4.855	4.410	4.310	4.378	55.207	22.605	19.504	13.098
3	Standard Offer Deferral (Over) / Under Recovery		(0.002)	-	-	-	-	-	-	-	-	-	-	-	(0.002)	(0.002)	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ 0.002**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**				
6	Standard Offer Expense Detail																	
7	NUG Purchases [line 9 minus line 8]		$ 0.209	$ 1.393	$ 0.963	$ 0.837	$ 0.887	$ 1.109	$ 0.983	$ 0.802	$ 1.596	$ 1.023	$ 1.068	$ 0.828	$ 11.698	$ 4.289	$ 4.490	$ 2.919
8	Short Term Market Transactions [page 4, line 5]		4.489	3.318	3.484	3.686	3.339	3.225	3.898	4.632	3.259	3.387	3.242	3.550	43.509	18.316	15.014	10.179
9	Standard Offer Expense [line 2]		$ 4.698	$ 4.711	$ 4.447	$ 4.523	$ 4.226	$ 4.334	$ 4.881	$ 5.434	$ 4.855	$ 4.410	$ 4.310	$ 4.378	$ 55.207	$ 22.605	$ 19.504	$ 13.098
	Annual Interest Rate		1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%				

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Jan - May	$ 4.289
Jun - Sep	$ 4.490
Oct - Dec	$ 2.919

Cambridge Electric Light Company
Monthly NUG Generation
GWH

Line	Description		Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	VT yankee																	
2	Altresco-Pittsfield Replacement Power																	
3	Altresco-Pittsfield																	
4	NUGs Generation																	
5	Less: Assumed Line Losses @	1.95%																
6	Net GWH Delivered																	
7	Dist Co Settlement Price (line 8 / line 6)																	
8	Cost of NUG Purchases (page 1, line 7)																	

REDACTED

Cambridge Electric Light Company
Total NUG Cost
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Vermont Yankee																
2	Altresco - Pittsfield																
3	Total NUG Cost																

REDACTED

Cambridge Electric Light Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
	Cost																
1	Short Term SO	$ 3.312	$ 2.412	$ 2.580	$2.240	$ 2.268	$ 2.322	$ 3.011	$ 3.211	$ 2.331	$ 2.074	$ 2.036	$ 2.253	$30.050	$ 12.812	$ 10.875	$ 6.363
2	Mirant	2.024	1.638	1.651	1.707	1.592	1.542	1.668	1.778	1.559	1.440	1.365	1.472	19.436	8.612	6.547	4.277
3	Short Term SO Sales	(0.847)	(0.732)	(0.747)	(0.261)	(0.521)	(0.639)	(0.781)	(0.357)	(0.631)	(0.938)	(0.945)	(0.987)	(8.386)	(3.108)	(2.408)	(2.870)
4	Altresco-Pittsfield Replacement Power	-	-	-	-	-	-	-	-	-	0.811	0.786	0.812	2.409	-	-	2.409
5	Total ST Market Cost	$ 4.489	$ 3.318	$ 3.484	$3.686	$ 3.339	$ 3.225	$ 3.898	$ 4.632	$ 3.259	$ 3.387	$ 3.242	$ 3.550	$43.509	$ 18.316	$ 15.014	$ 10.179
6	GWH																
7	Short Term SO Sales (page 2, line 4)	(16.233)	(14.169)	(16.319)	(6.227)	(13.271)	(15.898)	(16.429)	(7.543)	(15.898)	(24.198)	(23.418)	(24.199)	(193.802)	(66.219)	(55.768)	(71.815)
8																	
9	ST Sales Price/MWH						40.20	47.55	47.35	39.70	38.75	40.35	40.80				

Note
Short term SO sales on line 3 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Cambridge Electric Light Company
Standard Offer Revenue
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues																
2	Residential	$ 0.654	$ 0.567	$ 0.463	$ 0.528	$ 0.387	$ 0.457	$ 0.556	$ 0.678	$ 0.528	$ 0.458	$ 0.481	$ 0.527	$ 6.284	$ 2.599	$ 2.219	$ 1.466
3	Commercial	3.917	4.018	3.857	3.877	3.709	3.744	4.177	4.585	4.161	3.811	3.700	3.721	47.277	19.378	16.667	11.232
4	Industrial	0.076	0.081	0.084	0.077	0.095	0.113	0.129	0.151	0.143	0.116	0.104	0.103	1.272	0.413	0.536	0.323
5	Street Light	0.053	0.045	0.043	0.041	0.035	0.020	0.019	0.020	0.023	0.025	0.025	0.027	0.376	0.217	0.082	0.077
6	Total Standard Offer Revenues	$ 4.700	$ 4.711	$ 4.447	$ 4.523	$ 4.226	$ 4.334	$ 4.881	$ 5.434	$ 4.855	$ 4.410	$ 4.310	$ 4.378	$ 55.209	$ 22.607	$ 19.504	$ 13.098
7	Standard Offer Price						$0.05100	$0.05100	$0.05100	$0.05100	$0.05100	$0.05100	$0.05100				
8	SOSFA Price						$0.01223	$0.01223	$0.01223	$0.01223	$0.01223	$0.01223	$0.01223				
9	GWH Sales																
10	Standard Offer GWH Sales	75.516	74.539	70.349	71.709	66.882	68.536	77.212	85.947	76.775	69.754	68.171	69.235	874.625	358.995	308.470	207.160

Cambridge Electric Light Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-04	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues [page 5, line 6]		$ (4.775)	$ (4.714)	$ (9.489)	$ (9.489)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		4.775	4.714	9.489	9.489
3	Standard Offer Deferral (Over) / Under Recovery		-	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ -**	**$ -**	**$ -**		**$ -**
6	Standard Offer Expense Detail					
7	NUG Purchases [line 9 minus line 8]		$ 0.296	$ 1.430	$ 1.726	$ 1.726
8	Short Term Market Transactions [page 4, line 5]		4.479	3.284	7.763	7.763
9	Standard Offer Expense [line 2]		$ 4.775	$ 4.714	$ 9.489	$ 9.489
	Annual Interest Rate		1.65%	1.65%		

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Jan - Feb $ 1.726

Cambridge Electric Light Company
Monthly NUG Generation
GWH

Line	Description		Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	VT yankee					
2	Altresco-Pittsfield Replacement Power					
3	Altresco-Pittsfield					
4	NUGs Generation					
5	Less: Assumed Line Losses @	1.95%				
6	Net GWH Delivered					
7	Dist Co Settlement Price (line 8 / line 6)					
8	Cost of NUG Purchases (page 1, line 7)					

REDACTED

Cambridge Electric Light Company
Total NUG Cost
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Vermont Yankee				
2	Altresco - Pittsfield				
3	Total NUG Cost				

REDACTED

Cambridge Electric Light Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
	Cost				
1	Short Term SO	$ 3.312	$ 2.412	$ 5.724	$ 5.724
2	Mirant	2.024	1.638	3.662	3.662
3	Short Term SO Sales	(0.857)	(0.766)	(1.623)	(1.623)
4	Altresco-Pittsfield Replacement Power	-	-	-	-
5	Total ST Market Cost	$ 4.479	$ 3.284	$ 7.763	$ 7.763
6	GWH				
7	Short Term SO Sales (page 2, line 4)	(16.429)	(14.839)	(31.268)	(31.268)
8					
9	ST Sales Price/MWH	52.15	51.60		

Note
Short term SO sales on line 3 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Cambridge Electric Light Company
Standard Offer Revenue
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues				
2	Residential	$ 0.658	$ 0.567	$ 1.225	$ 1.225
3	Commercial	3.987	4.021	8.008	8.008
4	Industrial	0.077	0.081	0.158	0.158
5	Street Light	0.053	0.045	0.098	0.098
6	Total Standard Offer Revenues	$ 4.775	$ 4.714	$ 9.489	$ 9.489
7	Standard Offer Price	$ 0.05100	$ 0.05100		
8	SOSFA Price	$ 0.01223	$ 0.01223		
9	GWH Sales				
10	Standard Offer GWH Sales	75.516	74.539	150.055	150.055

Cambridge Electric Light Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-04	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues [page 5, line 6]		$ (4.775)	$ (4.714)	$ (9.489)	$ (9.489)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		4.775	4.714	$ 9.489	9.489
3	Standard Offer Deferral (Over) / Under Recovery		-	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ -**	**$ -**	**$ -**		**$ -**
6	Standard Offer Expense Detail					
7	NUG Purchases [line 9 minus line 8]		$ (0.098)	$ 1.078	$ 0.980	$ 0.980
8	Short Term Market Transactions [page 4, line 5]		4.873	3.636	$ 8.509	8.509
9	Standard Offer Expense [line 2]		$ 4.775	$ 4.714	$ 9.489	$ 9.489
	Annual Interest Rate		1.65%	1.65%		

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Cambridge Electric Light Company
Monthly NUG Generation
GWH

Line	Description		Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	VT yankee					
2	Altresco-Pittsfield Replacement Power					
3	Altresco-Pittsfield					
4	NUGs Generation					
5	Less: Assumed Line Losses @	1.95%				
6	Net GWH Delivered					
7	Dist Co Settlement Price (line 8 / line 6)					
8	Cost of NUG Purchases (page 1, line 7)					

REDACTED

Cambridge Electric Light Company
Total NUG Cost
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Vermont Yankee				
2	Altresco - Pittsfield				
3	Total NUG Cost				

REDACTED

Cambridge Electric Light Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
	Cost				
1	Short Term SO	$ 3.312	$ 2.412	$ 5.724	$ 5.724
2	Mirant	2.024	1.638	3.662	3.662
3	Short Term SO Sales	(0.463)	(0.414)	(0.877)	(0.877)
4	Altresco-Pittsfield Replacement Power	-	-	-	-
5	Total ST Market Cost	$ 4.873	$ 3.636	$ 8.509	$ 8.509
6	GWH				
7	Short Term SO Sales (page 2, line 4)	(8.886)	(8.026)	(16.912)	(16.912)
8					
9	ST Sales Price/MWH	52.15	51.60		

Note
Short term SO sales on line 3 are calculated using the Short Term SO GWH on line 7 by the selling price on line 15
on line 7 by the selling price on line 9.

Cambridge Electric Light Company
Standard Offer Revenue
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues				
2	Residential	$ 0.658	$ 0.567	$ 1.225	$ 1.225
3	Commercial	3.987	4.021	8.008	8.008
4	Industrial	0.077	0.081	0.158	0.158
5	Street Light	0.053	0.045	0.098	0.098
6	Total Standard Offer Revenues	$ 4.775	$ 4.714	$ 9.489	$ 9.489
7	Standard Offer Price	$ 0.05100	$ 0.05100		
8	SOSFA Price	$ 0.01223	$ 0.01223		
9	GWH Sales				
10	Standard Offer GWH Sales	75.516	74.539	150.055	150.055

EXHIBIT NSTAR-COM-GOL-1

POWER SALE AGREEMENT

by and between

ALTRESCO PITTSFIELD, L.P.

and

COMMONWEALTH ELECTRIC COMPANY

for a 17.2 percent entitlement
to the electric capacity and related energy
to be produced by
an approximately 160 megawatt gas-fired
cogeneration facility
located in Pittsfield, Massachusetts

[1A-74]

POWER SALE AGREEMENT

Agreement entered into this 20th day of February, 1992 by and between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company"), and Altresco Pittsfield, L.P., a Delaware limited partnership duly authorized to do business in the Commonwealth of Massachusetts with its principal place of business at 600 South Cherry Street, Denver, Colorado (the "Seller").

The Seller operates an electric cogeneration facility, consisting of a gas-fired, combined cycle generation plant, together with housings and other integral equipment, and which is capable of generating approximately one-hundred sixty megawatts (160 MW) of electricity (the "Unit"). The Unit is located in Pittsfield, Massachusetts, at a site owned by General Electric Company (the "Lessor"), more particularly described in Appendix A attached hereto (the "Site"). The Seller has leased the Site from the Lessor for the full anticipated term of this Agreement. The Seller wishes to sell and deliver and the Company wishes to purchase and take delivery of a percentage of the electric capacity and related energy produced by the Unit, pursuant to the terms and conditions set forth in this Agreement.

Therefore, the parties, each in consideration of the agreements of the other, hereby agree as follows.

ARTICLE 1. Definitions.

When used with initial capitalizations, whether in the singular or in the plural, the following terms shall have the following meanings.

Actual In-Service Date shall be the later to occur of (i) September 1, 1993, or (ii) the date on which all transmission services necessary to deliver power hereunder are secured pursuant to Article 3.2 of this Agreement.

Billing Period shall mean any calendar month in which the Unit produces electricity pursuant to this Agreement and for which the Company is obligated to pay for such electricity produced for such month pursuant to this Agreement.

Capability shall mean the maximum dependable load carrying ability of the Unit during the applicable Seasonal Period (exclusive of capacity required for Unit use). Capability shall be determined by the NEPOOL Operations Committee in accordance with NEPOOL Criteria, Rules and Standards ("CRS") Nos. 4 and 26. In the event that CRS No. 4 or No. 26 ceases to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that would have the same effect as these CRS's in determining Capability.

Capability Audit shall mean a test of the Unit's Capability conducted periodically pursuant to the provisions of Section 8.13 of the NEPOOL Agreement or any properly issued replacement therefor created from time to time during the term of this Agreement.

Capacity Deficiency shall mean the amount, if any, by which the Company's Capacity Entitlement is less than twenty-five thousand kilowatts (25,000 kW) during the Summer Period and is less than twenty-seven thousand kilowatts (27,000 kW) during the Winter Period.

Company's Capacity Entitlement shall be equal to the product of (i) the Company's Entitlement, multiplied by (ii) the audited Capability during the applicable Seasonal Period; provided, however, that the Company's Capacity Entitlement shall not exceed the maximum amount of electric capacity that the Company is obligated to purchase in accordance with Article 2.1 of this Agreement.

Company's Entitlement shall mean 17.2 percent (17.2%), which is the ratio of the Summer Period Contract Capacity to the Summer Period Design Capacity.

Company's Solicitation shall mean the Second Request for Proposals for Qualifying Facility Generation, dated 1990, issued by the Company pursuant to the regulations of the MDPU as set forth at 220 C.M.R. 8.00.

Contract Capacity shall mean twenty-five thousand kilowatts (25,000 kW) during the Summer Period and twenty-eight thousand, four-hundred kilowatts (28,400 kW) during the Winter Period.

Delivered Energy shall mean, for each Billing Period, the product of (i) 0.99 and (ii) the kilowatthours metered during the Billing Period pursuant to Article 7 of this Agreement minus the Non-Pool transmission losses (in kilowatthours) as may be applicable to the wheeling agreement pursuant to which the Company's Entitlement to electricity produced by the Unit will be transmitted to the Delivery Point.

Delivery Point shall mean the point at which the Company's transmission or distribution system connects with the transmission or distribution system of New England Power Company, which is the adjacent utility that is wheeling the electricity produced by the Seller to be purchased by the Company.

Design Capacity shall mean one-hundred forty-five megawatts (145 MW) during the Summer Period and one-hundred sixty-five megawatts (165 MW) during the Winter Period.

Economic Dispatch shall mean the operation of the Unit in accordance with such procedures as may be established by NEPOOL from time to time to foster the objective of satisfying the energy requirements of the participants of NEPOOL at the lowest practicable cost.

FERC shall mean the Federal Energy Regulatory Commission.

Good Utility Practice shall mean the practice, methods, and acts (including but not limited to the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should have been known at the time a decision was made, would have been expected to accomplish the desired result in a manner consistent with law, regulation, reliability, safety, environmental protection, economy, and expediency. With respect to the Unit, Good Utility Practice includes but is not limited to taking reasonable steps to ensure the following.

(1) That adequate materials, resources, and supplies, including fuel, are available to meet the Unit's needs;

(2) That sufficient operating personnel are available and are adequately experienced, trained, and licensed as necessary to operate the Unit properly and efficiently, and who are capable of responding to emergency conditions whether caused by events on or off the Site;

(3) That preventative, routine, and non-routine maintenance and repairs are performed on a basis that ensures reliable long-term and safe operation, and are performed by knowledgeable, trained, and experienced personnel utilizing proper equipment and tools;

(4) That appropriate monitoring and testing are performed to ensure that equipment is functioning as designed;

(5) That equipment is not operated recklessly, or in a manner that is unsafe to workers, the general public, or the environment, or without regard to defined limitations such as steam pressure, temperature, and moisture content, chemical content of make-up water, flood conditions, safety inspection requirements, operating voltage, current, frequency, rotational speed, polarity, synchronization, or control system limits;

(6) That equipment will function properly under both normal and emergency conditions; and

(7) That the Unit is operated in conformance with NEPOOL CRS's and Operating Procedures, and NEPEX dispatch instructions.

MDPU shall mean the Massachusetts Department of Public Utilities.

NEPOOL shall mean the New England Power Pool. The term "NEPOOL" shall include NEPEX, the central dispatching agency, as defined in Section 15.22 of the NEPOOL Agreement, operating through such satellite dispatching centers as the NEPOOL Management Committee may determine to be appropriate.

NEPOOL Agreement shall mean the New England Power Pool Agreement, dated September 1, 1971, as amended.

Qualifying Facility ("QF") shall mean a cogeneration facility or a small power production facility that meets the requirements of Subpart B of the regulations of the FERC as set forth at 18 C.F.R. 292, et seq., implementing the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. § 2601, et seq.), and is so certified by the FERC in accordance with its procedures.

Seasonal Period shall mean either the Summer Period, June through September, or the Winter Period, October through May, as appropriate.

System Emergency shall mean an imminent condition on the Company's or a neighboring utility's system that is likely to result in significant disruption of service or is likely to endanger life or property.

Testing Period shall mean any period during which the Unit is being tested and may produce electric energy prior to the Actual In-Service Date.

Test Power shall mean any electric energy produced by the Unit during the Testing Period.

ARTICLE 2. Sale of Power.

2.1 The Seller agrees to sell and deliver and the Company agrees to purchase and take delivery of the Company's Entitlement of electric capacity and related energy produced by the Unit during the term of this Agreement; provided, however, that in

no event shall the Company be obligated to purchase electric capacity and related energy in excess of twenty-six megawatts (26 MW) during the Summer Period and twenty-nine and one-half megawatts (29.5 MW) during the Winter Period; and provided further, that in no event shall the Company be obligated to purchase and take delivery of related energy in excess of twenty-eight megawatts (28 MW) per hour during the Summer Period and thirty megawatts (30 MW) per hour during the Winter Period, except for those hours during which NEPOOL has ordered the Unit to be operated under Operating Procedure 4 conditions. The Seller may refrain from selling and delivering such electric energy as it may need from time to time to satisfy Unit requirements.

2.2 The Unit shall be staffed, tested, operated, and maintained in accordance with Good Utility Practice and in a manner consistent with the standards applicable to generating facilities owned and operated by participants in NEPOOL, as such standards may be in effect from time to time during the term of this Agreement. The Seller also agrees to make the Unit available for NEPOOL dispatch in accordance with the provisions of Section 12.2 of the NEPOOL Agreement.

2.3 In addition to the foregoing, the Seller shall undergo upon the request of the Company periodic Capability Audits.

2.3.1 In the event that the Unit demonstrates a Capacity Deficiency in excess of one megawatt (1 MW) (the "Threshold Amount"), the Company may assess the Seller an offset charge each month, which charge shall be equal to one twelfth (1/12) of the sum of the annual Capability Responsibility Adjustment Charge plus the annual Capability Responsibility Deficiency Charge, established from time to time by NEPOOL pursuant to the provisions of Section 9.4 of the NEPOOL Agreement, multiplied by such Capacity Deficiency.

2.3.2 In the event that the Unit demonstrates a Capacity Deficiency not in excess of the Threshold Amount, the Company may assess the Seller an offset charge therefor only if and to the extent that the Company is assessed any charges by NEPOOL as a result of such Capacity Deficiency.

2.4 During the Testing Period, the Unit may generate Test Power. The Company agrees to take and pay for any Test Power offered for sale, up to the Company's Entitlement thereof, subject to the following conditions: (i) the tests conducted during the Testing Period shall be performed in accordance with Good Utility Practice, (ii) the administrative committee established pursuant to Article 17.6 of this Agreement shall be kept informed of operations during the Test Period, and (iii) the Company shall pay for any Test Power monthly at a price determined pursuant to the Company's effective, generally available Rate P-1 "Power Purchase" rate (as of the date hereof, MDPU No. 251), or any generally available replacement therefor as may be issued by the Company from time to time.

ARTICLE 3. Effective Date and Term.

3.1 This Agreement shall become effective when all necessary approvals have been received, in a form acceptable to both parties, from the MDPU; provided, however, that the Company's obligation to purchase electric capacity and related energy (other than pursuant to Article 2.4 of this Agreement) shall not commence until the Actual In-Service Date. Unless sooner terminated in accordance with any applicable

provision hereof, this Agreement shall remain in full force and effect until December 31, 2011.

3.2 If all transmission services necessary to deliver power hereunder have not been secured within twenty-four (24) months following the date first above-written, either party may terminate this Agreement upon sixty (60) days written notice to the other.

ARTICLE 4. Dispatchability.

4.1 The Unit shall be subject to Economic Dispatch at the direction of the Company or NEPOOL; provided, however, that the Unit shall be subject to Economic Dispatch at the sole direction of NEPOOL if, and only if, such dispatch is fully in accordance with the provisions of this Article 4. The Company or NEPOOL, as appropriate, may call for up to three hundred (300) stops (that is, when the Unit is to be reduced to a zero percent (0%) load level) and up to three hundred (300) restarts of the Unit per year. The Unit shall be subject to changes in the level of its output at the direction of the Company or NEPOOL, as appropriate, provided that such changes are within the Unit's reasonable design limitations.

4.2 Subject to the provisions of Article 10 of this Agreement, if the Seller fails to dispatch the Unit as called for by the Company or NEPOOL, as appropriate, then the following terms and conditions shall apply:

4.2.1 The Company shall calculate the uneconomic incremental production costs it incurs that are attributable to such failure of the Seller (the "Incremental Production Cost Penalty"). The Company shall also not pay for any electric energy produced at the Unit as a result of the Seller's failure to comply with the calls of the Company or NEPOOL, as appropriate, pursuant to Article 4.1 above. The Incremental Production Cost Penalty shall be the amount, if any, by which the production costs that the Company experienced during the period of the Seller's failure to dispatch the Unit as called for by the Company or NEPOOL, as appropriate, exceed the production costs that the Company would have experienced during such period had the Seller complied with the call of the Company or NEPOOL, as appropriate, to dispatch the Unit.

4.2.2 Notwithstanding the foregoing, if and to the extent that the dispatch of the Unit, as prescribed in Article 4.1, becomes proscribed because the Seller had declared that it must operate the Unit under a minimum load level of forty-four (44) megawatts (or less), then the provisions of Article 4.2.1 relating to the Incremental Production Cost Penalty shall not apply; provided, however, that such condition may not exceed two-thousand (2,000) hours in any calendar year, nor shall the aggregate share of the Company and its affiliate Cambridge Electric Light Company (which pursuant to an agreement between it and the Seller, dated as of the date hereof, is purchasing an equal percentage of the electric capacity and related energy to be produced by the Unit) of such minimum load exceed fifteen (15) megawatts; and provided further that this Article 4.2.2 shall apply only so long as a FERC-approved system exchange agreement with New England Power Company in respect of the electric energy resulting by reason of such minimum load condition is in place.

4.3 The Company shall net any Incremental Production Cost Penalty against any payments due the Seller for any electric capacity and energy purchased by the

Company during the Billing Period ("Net Billing Amount"). In the event that the Net Billing Amount for a Billing Period is owed to the Company, such Net Billing Amount shall be billed to the Seller and the Seller shall reimburse the Company therefor according to the same standards as are established for payments to the Seller.

ARTICLE 5. Purchase Price.

From and after the Actual In-Service Date, the Company shall pay the Seller each month, in accordance with the provisions of Article 8 of this Agreement, an amount equal to the Total Purchase Price, as determined in accordance with Appendix B attached hereto.

ARTICLE 6. Delivery by the Seller.

6.1 The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electric energy at or near the Design Capacity on a continuous twenty-four (24) hour basis for the full term of this Agreement. The Seller agrees that it will limit its sales of the thermal output of the Unit to two hundred thirty-one thousand (231,000) pounds per hour unless, in the judgment of the Company, any increased sales would not adversely affect the ability of the Seller to be capable of so operating the Unit and of fulfilling its obligations under this Agreement.

6.2 As of the date hereof, the parties expect that the Delivery Point will consist of a point of interconnection between the Company's and an adjacent utility's transmission systems of three hundred forty-five thousand volts (345 kV) nominal (the "Interconnection Voltage"). The parties recognize that it could become necessary or appropriate in the future to designate a different point of interconnection between the Company's and an adjacent utility's transmission systems of a differing voltage, such as one hundred fifteen thousand volts (115 kV) nominal. In the event that the parties so agree in the future, the Interconnection Voltage shall be defined accordingly, and further, the Company shall be entitled to recalculate any wheeling losses reflected in the definition of "Delivered Energy" contained in Article 1 of this Agreement. In any case, electric energy generated by the Unit shall be delivered to the Company at the Delivery Point in the form of three (3) phase, sixty (60) hertz, alternating current at the Interconnection Voltage.

6.3 The Seller may from time to time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance or repair upon the Unit. The Seller shall comply with the provisions of NEPOOL Operating Procedure No. 5 as in effect from time to time when planning any scheduled maintenance or repair upon the Unit. If the Seller should fail to comply with such NEPOOL Operating Procedure, then the Company may assess the Seller a charge each Billing Period during which such non-compliance occurs, which charge shall be calculated and collected pursuant to the provisions of Articles 4.2 and 4.3 of this Agreement governing the Incremental Production Cost Penalty. The Seller shall promptly inform the Company, both orally and in writing, of each scheduled or unscheduled withdrawal of the Unit from service, and shall notify the Company of the reasons therefor and the expected duration thereof when such information is known.

ARTICLE 7. Meters and Metering.

7.1 The Company shall review and approve the metering installations required to record the quantities of electricity purchased from the Seller, such approval not to be unreasonably withheld. Such metering equipment will be capable, inter alia, of providing data required to determine kilowatts purchased during each hour of the month as well as total kilowatthours purchased each month under the terms of this Agreement. The Seller shall install, own, operate, and maintain such metering equipment, which equipment shall be located at the Seller's high voltage bus or buses. If, for any reason, it is impractical to install meters at such bus or buses, appropriate adjustments shall be made to reflect the actual amount of electric energy that would have been recorded by meters located at such bus or buses, as agreed to by the Company and the Seller.

7.2 The Seller shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards. The metering equipment shall be sealed, and the Seller shall comply with any reasonable request of the Company with regard to the presence of the Company's representative when such seals are to be broken or when the meters are to be inspected, tested, or adjusted. The Company may at any time request a test of the accuracy of any metering equipment installed pursuant hereto and shall bear the costs thereof in the event that said requests are made more frequently than once in each twelve (12) months. The results of all meter calibrations or tests, regardless of whether performed at the Company's request, shall be open to examination by the Company at all reasonable times.

7.3 Any meter tested and found to register less than or equal to one half of one percent (0.5%) above or below the recognized comparative standard shall be considered correct and accurate. If the metering fails to operate or, as a result of such tests, the metering equipment is found to be defective or inaccurate, the Seller shall restore it to a condition of accuracy or replace it. In such event, appropriate adjustments shall be agreed to by the Seller and the Company and reflected in the next monthly statement of the Seller rendered pursuant to Article 8.1 of this Agreement. Such adjustments shall correct all measurements made by the defective or inaccurate meter for either (i) the actual period during which inaccurate measurements were made, if determinable to the mutual satisfaction of the Company and the Seller, or (ii) if such period is not determinable, for a period equal to one half of the time elapsed since the last prior test, but in no event greater than twelve (12) months.

7.4 Other provisions of this Article notwithstanding, the Company may elect to install its own metering equipment in supplement to the Seller's metering equipment. Should any metering equipment installed by the Seller fail to register the amount of electric energy delivered to the Company during any period, the Company's metering equipment shall, if so installed, be used to determine the amount of electric energy so delivered. If the Company wishes its metering equipment to be so used, the Company agrees to operate, maintain, and read such equipment according to the standard established by this Article with respect to the Seller's metering equipment. The Seller agrees, upon the request of the Company, to provide a suitable location at the Site for installation of the Company's meters at no cost to the Company.

7.5 Upon the written request of the Company, the Seller shall install, own, operate, and maintain, pursuant to the provisions of this Article, such telemetering equipment and data circuits as the Company may reasonably require for the transmission of various metered values to its operations center. The design equipment and data circuits shall

be approved by the Company prior to their installation by the Seller, such approval not to be unreasonably withheld. Upon the failure of the Seller to install such telemetering equipment and data circuits within a reasonable period following the request of the Company to do so, the Company may install such equipment and data circuits at the expense of the Seller.

ARTICLE 8. Billing and Payment.

8.1 The Seller shall render monthly statements for the Billing Period then most recently ended within ten (10) business days following the close of such Billing Period, detailing the amount of Delivered Energy during such Billing Period. Any amount payable hereunder not paid within thirty (30) days from the date of receipt by the Company of such monthly statement (or, if such date is not a business day, then by the next business day thereafter) shall be subject to a late payment charge at the annual rate of two (2) percentage points over the current prime interest rate on commercial loans then in effect at the First National Bank of Boston from the date of such receipt of such monthly statement until the date of payment.

8.2 In the event that any data required for billing purposes hereunder are unavailable when needed for such billing, the unavailable data may be estimated by the Seller, subject to any required adjustment, based upon actual data, in a subsequent Billing Period. The Seller shall make all data upon which any estimated data are based available to the Company. No late payment charge shall be imposed on amounts owed by the Company to the Seller, or by the Seller to the Company, as a result of any such subsequent adjustment.

8.3 Neither the Company nor the Seller shall have the right to challenge any monthly statement rendered or received hereunder, to invoke arbitration of the same, or to bring any court or administrative action of any kind questioning the propriety of said monthly statement, after a period of one (1) year from the date such monthly statement was rendered. In the event that any such monthly statement depends in whole or part upon estimated data, this one (1) year limitation period shall be deemed to begin in the Billing Period in which such estimated data are adjusted to actual.

ARTICLE 9. Governmental Regulation.

9.1 As soon as practicable after execution, this Agreement shall be submitted by the Company to the MDPU in accordance with the regulations of the MDPU as set forth at 220 C.M.R. 8.00.

9.2 Each party hereto shall be responsible for taking all necessary actions to satisfy any regulatory requirements that may be imposed by any federal, state, or municipal statute, rule, regulation, or ordinance that may be in effect from time to time relative to the performance of such party hereunder.

9.3 This Agreement and all rights and obligations of the parties hereunder are subject to all applicable state and federal laws and all duly promulgated orders and duly authorized actions of governmental authorities.

ARTICLE 10. Liability and Force Majeure.

10.1 The parties hereto shall be excused from performing hereunder and shall not be liable in damages or otherwise if and to the extent that they are unable to do so or are prevented from doing so by statute or regulation, or by action of any court or public authority having or purporting to have jurisdiction in the premises; or by reasons of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or regulatory agency, or any other cause, regardless of whether similar thereto, beyond the reasonable control of the affected party. Each party shall have the obligation to operate in accordance with Good Utility Practice at all times and to use diligent effort to overcome and remove any cause of failure to perform. The party subject to any such event of force majeure shall promptly inform the other party thereof, both orally and in writing, setting forth the nature of such event and its expected duration.

10.2 Neither the Company nor the Seller shall, in any event, be liable to the other or to any third party for any consequential, indirect, or special damages to persons or property, whether arising in tort, contract, or otherwise, by reason of this Agreement or any services performed or undertaken to be performed by the Company or the Seller hereunder.

10.3 Whenever the Company's system or any system with which it is directly or indirectly interconnected experiences a System Emergency, or whenever it is necessary or desirable to aid in the restoration of service on its system or on any system with which it is directly or indirectly interconnected, the Company may, in its reasonable judgment, curtail or interrupt the taking of electric energy hereunder, provided such curtailment or interruption shall continue only for so long as is reasonably necessary. Such curtailment, interruption, or reduction shall not be deemed to be a default by the Company nor shall the Company be liable therefor to the Seller or to any other party. The Company will provide the Seller with such notice as is reasonably practical under the circumstances regarding the nature, extent, and expected duration of a System Emergency.

10.4 The Company and the Seller agree that each shall be responsible for the electricity on its respective side of the Delivery Point and shall indemnify, save harmless, and defend the other against all claims, demands, costs, or expenses for loss, damage, or injury to persons or property in any manner directly or indirectly arising from, connected with, or growing out of the presence, use, or transmission of electricity over the wires, cables, devices, or appurtenances owned by it. The Company and the Seller each assumes full responsibility in connection with the service rendered hereunder for its respective wires, cables, and other devices used in connection with such service. Each party hereto shall be solely liable for all claims of its own employees arising from any worker's compensation laws.

10.5 Neither by inspection, by non-rejection, nor in any other way does either party give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any equipment, apparatus, or devices installed on the other party's premises.

ARTICLE 11. Governing Law.

The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the Commonwealth of Massachusetts.

ARTICLE 12. Arbitration.

12.1 In the case of any dispute between the parties with respect to the interpretation of this Agreement or the performance of the same, either party may give notice in writing to the other of its desire to submit such questions to arbitration and may designate an arbitrator. Within thirty (30) days after the receipt of such notice the other party may, in writing, serve upon the party invoking such arbitration a notice designating an arbitrator on its behalf. The two arbitrators so chosen shall, within twenty (20) days after the appointment of the second arbitrator, in writing, designate a third arbitrator. Upon the failure of the party notified to appoint the second arbitrator within such time, the party invoking such arbitration may proceed with the single arbitrator. If the first and second arbitrators are unable to agree on a third arbitrator within twenty (20) days of the appointment of the second arbitrator, the first and second arbitrator shall invoke the services of the American Arbitration Association to appoint a third arbitrator. This third arbitrator shall, to the extent practicable, have special competence and experience with respect to the subject matter under consideration. An arbitrator so appointed shall have full authority to act pursuant to this Article. No arbitrator, whether chosen by a party hereto or appointed, shall have the power to amend or add to this Agreement. Unless the parties otherwise agree, the place of any arbitration held pursuant to this Article 12 shall be Boston, Massachusetts.

12.2 The party calling the arbitration shall, within twenty (20) days after either the failure of the other party to name an arbitrator or the appointment of the third arbitrator, as the case may be, fix, in writing, a time and a place of hearing, to be not less than twenty (20) days from the delivery of notice to the other party. The arbitrator or arbitrators (the "Arbitrators") shall, thereupon, proceed promptly to hear and determine the controversy pursuant to the then current rules of the American Arbitration Association for the conduct of commercial arbitration proceedings, except that if such rules conflict with the then current provisions of the laws of the Commonwealth of Massachusetts relating to arbitration, such conflict shall be governed by the then current provisions of such laws of the Commonwealth of Massachusetts. The Arbitrators shall fix a time within which the matter shall be submitted to them by either or both of the parties, and shall render a decision within ten (10) days after the final submission from the parties to them unless, for good reasons to be certified by them in writing, the Arbitrators extend such time. The decision of the single arbitrator, or two of the three arbitrators, shall be taken as the arbitration decision. Such decision shall be made in writing and in duplicate, and one copy shall be delivered to each of the parties. The arbitrators by their award shall determine the manner in which the expenses of the arbitration shall be borne, except that each party shall pay the costs of its own counsel. Each party shall accept and abide by the arbitration decision. The award of the Arbitrators shall be final except as otherwise provided by applicable law. Judgment upon such award may be entered by the prevailing party in any court having jurisdiction thereof, or application may be made by such party to any such court for judicial acceptance of such award and an order of enforcement.

12.3 The party on which a demand for arbitration pursuant to this Article 12 is served shall have the right to remove the dispute that is the subject of such a demand by petitioning an appropriate regulatory forum where such dispute can receive recognition and cognizance (including, without limitation, the MDPU and the FERC); provided however, that such right shall not apply to disputes that involve

issues wholly operational or technical; and provided further, that in the event the applicable regulatory agency does not from the date of such petition: (i) accept the petition for jurisdiction within thirty (30) days; (ii) conduct and commence adjudicatory hearings (as applicable) within sixty (60) days; or (iii) issue a decision on the subject dispute within one-hundred eighty (180) days, then the party calling the arbitration shall have the right to invoke the arbitration process in accordance with Paragraphs 12.1 and 12.2, above.

ARTICLE 13. Insurance.

13.1 From and after the Actual In-Service Date, the Seller shall (i) keep the Unit insured, at all times, by means of a policy or policies of insurance, in amounts not less than that reasonably required by the Company, protecting against loss or damage to the Unit by fire, lightning, and other casualties normally insured against with a uniform standard extended coverage endorsement; and (ii) maintain comprehensive general liability insurance as described in Appendix C attached hereto. The Company shall be a named insured in these policies, which policies shall contain a waiver of subrogation in favor of the named insured. All policies, or copies thereof, together with a certificate from the insurers evidencing that the policies are currently in force, shall be delivered to the Company.

13.2 Such insurance shall be provided by policies that shall be written by such companies and in such form as shall be generally commercially available and acceptable to the Company, such acceptance not to be unreasonably withheld; shall be primary and without right to contribution from other insurance that may be available; shall provide that, with respect to the Company, the insurance shall not be invalidated by any action or inaction by the Seller including, without limitation, any representation made by or on behalf of the Seller in the procurement of such insurance; and shall provide that such insurance shall not be canceled or amended without at least thirty (30) days prior written notice to the Company.

13.3 Not less than thirty (30) days prior to the expiration date of each policy obtained by the Seller in accordance with this Article, the Seller shall deliver to the Company a renewal policy or policies accompanied by evidence of payment of the premium therefor.

13.4 The amount of any proceeds of insurance described in this Article remaining after deducting all expenses (including attorney fees) incurred in the collection of such proceeds from the gross proceeds thereof shall be applied to the prompt repair, restoration, modification, or improvement of that portion of the Unit damaged or destroyed by such casualty, unless the Seller and the Company (in coordination with other purchasers) have agreed that such repair, restoration, modification, or improvement is not practicable under the circumstances.

ARTICLE 14. Preservation of the Unit.

14.1 The Seller in its sound discretion may sell or otherwise dispose of only that machinery, equipment, or other personal property constituting part of the Unit that the Seller determines has become inadequate, obsolete, worn out, unsuitable, undesirable, or unnecessary, provided that (i) substitute property having equal or greater utility, but not necessarily the same function, in the operation of the Unit is installed at the Unit and such removal and substitution would not materially impair

the efficiency of operation of the Unit, adversely affect the structural integrity or electrical output of the Unit, or change the nature of the Unit to the extent that it would not constitute the type of electricity generation facility operated prior to such replacement; and (ii) the prior written consent of the Company is obtained, which consent shall not be unreasonably withheld, and which consent shall not be required for removals and substitutions made during the course of ordinary and routine repair and maintenance. The Seller shall promptly report to the Company each such removal, substitution, sale, or other disposition. In addition, not less often than semi-annually, the Seller shall make available to the Company's representatives on the administrative committee described in Article 17.6 of this Agreement all records with respect to prior dispositions and substitutions, together with information as to planned dispositions and substitutions during the next six (6) months.

14.2 The Seller shall pay or cause to be paid all taxes, payments in lieu of taxes, assessments, and other charges now or hereafter levied against the Unit or any part thereof, together with any penalties or interest on any of the foregoing; subject to the right of the Seller and other parties in interest to contest in good faith the levying of such charges. The Seller shall promptly notify the Company as to any impending lien to be imposed upon the Site due to the nonpayment of any such charges, and upon the request of the Company, shall exhibit to the Company receipts for the payment thereof.

14.3 The Seller warrants that it holds, and that at the time security will be furnished to the Company pursuant to Article 15 it will hold, a leasehold interest in the Site for the full anticipated term of this Agreement, subject only to any mortgages, liens, leases, or other encumbrances existing as of record and copies of which will have been provided to the Company at the time of furnishing such security. The Seller also warrants that it holds, and that at the time security will be furnished to the Company pursuant to Article 15 it will hold, either a leasehold interest in the Unit for the full anticipated term of this Agreement or good record and marketable title to the Unit, subject only to any mortgages, liens, or other encumbrances existing as of record and copies of which will have been provided to the Company at the time of furnishing such security. The Seller shall not enter into any transaction involving the transfer, sale, or lease of the Site or the Unit, or any interest therein, without the prior written consent of the Company in each case obtained, which consent shall not be unreasonably withheld. Such transfer, sale, or lease shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against an entity that might thereby obtain title to or possession of the Site or Unit.

14.4 The Seller will maintain the Unit and the Site, or cause the Unit and the Site to be maintained, in accordance with Good Utility Practice; will not commit or suffer any waste thereof or the conduct of any nuisance or unlawful occupation or business on, or use of, the Unit or the Site; and will comply, or cause compliance, with all statutes, ordinances, and requirements of any governmental authority relating to the Unit and the Site; and the Seller at its expense shall provide the Company with a report, on a biennial basis for the first ten (10) years of the term of this Agreement and on an annual basis thereafter, prepared by a nationally recognized firm of consulting engineers of Seller's choosing and approved by the Company, such approval not to be unreasonably withheld, attesting to the fact that the Unit is being maintained in accordance with Good Utility Practice. If substantial items affecting long-term efficient operation of the Unit that are described in any such annual report as being in need of correction are not corrected within six (6) months following such annual report, the Company may withhold payment each month of that portion of the Total

Purchase price equal to one sixth (1/6) of the amount required to correct such items, with such amounts to be held in escrow by the Company until the cited items have been corrected, upon which correction the escrowed funds shall be released to the Seller. Notwithstanding the foregoing, if any such correction is not made within twelve (12) months from the date of such annual report, the Company may elect to cause such correction to be made and the escrowed funds shall be applied to cover the costs of such correction. In the event that the Seller challenges the validity of any item contained in such report and the parties are unable to resolve upon such item, the matter shall be set for arbitration in accordance with the provisions of Article 12 of this Agreement. No such challenge or arbitration shall affect the Company's rights to withhold and place in escrow amounts necessary to correct such item as set forth herein.

14.5 The Company and any persons authorized by the Company shall have the right to enter and inspect the Unit at all reasonable times upon reasonable prior written notice to the Seller and in coordination with the Lessor's reasonable requirements concerning access to the Site, and to examine Unit operating manuals and maintenance records.

ARTICLE 15. Security of Continued Performance.

The parties to this Agreement acknowledge that the Company and its ratepayers will incur costs hereunder such that the Company and its ratepayers expect to receive full consideration therefor only to the extent that the Seller's obligations hereunder are fully performed and electric capacity and related energy from the Unit are sold to the Company for the full anticipated term of this Agreement. Accordingly, in order to secure such complete performance of the Seller's obligations and the continued sale of electric capacity and related energy from the Unit to the Company, the Seller, prior to the Actual In-Service Date, shall provide to the Company security in the form and scope set forth below.

15.1 Mortgage and Security Agreement. The Seller shall execute and deliver to the Company a mortgage and security agreement creating liens and security interests in the Unit, the Seller's leasehold interest in the Site, all improvements upon the Site, and all rents, profits, income, and other benefits derived from the foregoing, subordinate only to the lien securing amounts lent for the acquisition of the Site and for the construction, establishment, and operation of the Unit; or to the lien of the institutional or unaffiliated lenders securing amounts otherwise lent in respect of the Unit. Such liens and security interests of the Company shall secure (i) all amounts paid by the Company to the Seller pursuant to this Agreement in excess of the Company's actual avoided costs, and (ii) performance of the Seller's obligations under this Agreement for the full anticipated term thereof, including all damages resulting from the Seller's failure to perform such obligations. Such mortgage and security agreement shall be in form and substance acceptable to the Company.

15.2 Declaration of Easements, Covenants, and Restrictions. The Seller shall cause to be granted to the Company an unsubordinated declaration of easements, covenants, and restrictions encumbering the Site for a period equal to the anticipated full term of this Agreement (the "Declaration"), which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. The Declaration shall grant to the Company easements for access to the Site and for the placement and operation of facilities thereon, as well as create restrictions and covenants to the effect that no electricity produced at the Site shall be sold unless and until the Company's Entitlement of such electricity is tendered to the Company in accordance

with this Agreement. The Declaration shall be in form and substance acceptable to the Company, shall run with the Site, shall be binding upon the successors of the Seller, and shall inure to the benefit of the Company and its successors.

15.3 Accommodation Agreement. The Seller shall cause any lender of funds to the Seller for the acquisition of the Site, for the construction, establishment, or operation of Unit, or otherwise in respect of the Unit (the "Lender") to execute and deliver an Accommodation Agreement, which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. Under the Accommodation Agreement, the Lender shall agree: (i) to make its own interests subject to the Declaration; (ii) to honor this Agreement to the extent the Lender is in possession of the Site or Unit; (iii) to transfer interests in the Site or Unit only upon the condition that the transferee become obligated to honor this Agreement; and (iv) not to disturb the Company's enjoyment of rights under this Agreement. The Seller shall similarly cause the Lessor to execute and deliver an Accommodation Agreement, making the interests of the Lessor subject to those of the Company pursuant to the Company's mortgage and security agreement and the Declaration.

15.4 Letter of Credit. The Seller shall provide, in form and substance acceptable to the Company, an irrevocable letter of credit in favor of the Company, which was offered by the Seller in order to obtain a higher ranking pursuant to the Company's Solicitation. The Seller shall maintain such letter of credit throughout the period during which payments by the Company to the Seller are expected to exceed the Company's projected avoided costs, as set forth according to the following schedule:

From	Through	Amount
September 1, 1993	December 31, 1993	$ 233,691
January 1, 1994	December 31, 1994	$1,926,663
January 1, 1995	December 31, 1995	$3,028,512
January 1, 1996	December 31, 1996	$4,208,628
January 1, 1997	December 31, 1997	$4,553,527
January 1, 1998	December 31, 1998	$4,810,488
January 1, 1999	December 31, 1999	$4,416,841
January 1, 2000	December 31, 2000	$2,988,934
January 1, 2001	December 31, 2001	$1,627,060

15.5 Coordination with Other Secured Parties. Each of the Company and the Seller (on its own behalf and on behalf of the Lender and the Lessor) agrees to negotiate in good faith reciprocally with respect to accommodating the various interests of the Company, the Lender and the Lessor at the time when the Seller has secured commitments for financing the Unit; provided, however, that the foregoing shall not diminish the obligation of the Seller, the Lender and the Lessor to fulfill the obligations due to be performed respectively by them hereunder. The Company further agrees to liaise with other purchasers of the electric output from the Unit with respect to coordinating their respective entitlements thereto.

ARTICLE 16. Rights of the Company with Respect to Expansion of the Unit and Extension of Unit Life.

The Seller shall not enter into any contract for the sale of electricity from any addition to or expansion of the Unit beyond the Design Capacity, from any other electric generation facilities located at the Site, or for any period beyond the term of this Agreement, until and

unless (i) the Seller shall have first offered to enter into a contract with the Company on terms substantially the same as those specified in any proposal or letter of intent between the Seller and any other party with respect thereto, and (ii) the Company does not accept such offer within thirty (30) days of the date presented to the Company in writing and be ready and willing to enter into a contract reflecting such business terms within sixty (60) days thereafter. The Company acknowledges and understands that other purchasers of electricity produced by the Unit may require similar rights to purchase electric energy generated by additions to or expansion of the Unit and during periods beyond the term of the original power purchase agreements entered into by such other purchasers, and the Company agrees that its rights pursuant to this Article 16 will relate only to such portion of any such expansion or extension as is equal to the Company's Entitlement. The Seller agrees to keep the Company fully and promptly apprised, through the administrative committee described in Article 17.6 of this Agreement, of any plans the Seller may develop for any addition to or expansion of the Unit or the development of any other generation facilities at the Site, which information the Company agrees not to disclose except with the Seller's prior written permission.

ARTICLE 17. Miscellaneous Provisions.

17.1 This Agreement shall constitute the entire agreement between the parties hereto relating to the subject matter hereof, and all previous agreements, discussions, communications, and correspondence with respect to the subject matter hereof shall be superseded by the execution of this Agreement.

17.2 This Agreement may not be modified or amended except in writing signed by or on behalf of both parties by their duly authorized officers.

17.3 In the event that any or all of the NEPOOL standards referred to herein shall cease to be established, or if the Company ceases participation in NEPOOL, the Company may impose reasonable substitute standards that do not materially alter the obligations of the Seller as such obligations existed under the NEPOOL standards.

17.4 This Agreement shall inure to the benefit of and bind the respective successors and assigns of the parties hereto, provided however, that no assignment by either party (or any successor or assignee thereof) of its rights and obligations hereunder (except an assignment by the Company of such rights and obligations to a wholly-owned subsidiary or an affiliate wholly-owned by the same holding Company, or an assignment by the Seller of such rights and obligations to such a subsidiary or affiliate whose principal functions are to own and operate the Unit), shall be made or become effective without the prior written consent of the other party in each case obtained, which consent shall not be unreasonably withheld. All assignments by the Seller or the Seller's successors and assigns shall be in such form as to assure that the Company's right to receive the electric output of the Site and Unit pursuant to the terms of this Agreement shall apply against any entity that might obtain title to or possession of the Site or Unit.

17.5 Notwithstanding any assignments of rights or duties hereunder, neither party shall be relieved of any duties or responsibilities under this Agreement and this Agreement shall continue in accordance with its terms and each party shall be and remain liable to the other under all provisions of this Agreement unless the other party has expressly consented in writing to such release of duties and responsibilities, such consent not to be unreasonably withheld. Further, any payments made by one party to an assignee of the other party or any other actions taken by such party with respect

to such assignee shall be in full satisfaction of any duties or responsibilities that the party would otherwise owe to the other party, as if made directly or taken with respect to such other party.

17.6 The parties hereto agree to establish an administrative committee, which shall serve informational functions only. Unless otherwise agreed by the administrative committee, such committee shall meet at least once each calendar quarter prior to the Actual In-Service Date and at least twice each year thereafter. The Company and the Seller shall have equal representation upon such committee.

17.7 The Company's obligations hereunder are conditioned upon the Unit being certified, on the Actual In-Service Date, as a Qualifying Facility. Further, the Seller shall use its best efforts to maintain such certification of QF status throughout the term of this Agreement. If, despite such efforts, certification of the Unit's QF status is revoked, suspended, or otherwise terminated after the Actual In-Service Date, the Seller shall use its best efforts to regain such certification and the Company and the Seller agree to continue to purchase and sell electric capacity and related energy from the Unit in accordance with the terms of this Agreement, including, without limitation, the purchase price provisions of Article 5 of this Agreement.

17.8 Any written notice required to be given hereunder shall be given by certified or registered mail, postage prepaid, return receipt requested, or by hand or personal delivery, at the addresses specified below, or at such other addresses as may be specified in writing by the party in question:

To the Seller: Howard D. Lutz, President
Altresco Financial, Inc.
Suite 1200
600 S. Cherry Street
Denver, Colorado 80222

(with a copy to: David S. Rosenzweig, Esq.
Keohane, DeTore & Keegan
21 Custom House Street
Boston, Massachusetts 02110)

To the Company: Commonwealth Electric Company
2421 Cranberry Highway
Wareham, Massachusetts 02571
Attention: Michael R. Kirkwood

(with a copy to: Michael F. Donlan, Esq.
Rich, May, Bilodeau & Flaherty, P.C.
294 Washington Street
Boston, Massachusetts 02108)

Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept.

17.9 If any provision of this Agreement is found to be prohibited or unenforceable, the remainder of this Agreement shall not be affected thereby and shall be valid and enforceable to the extent permitted by law.

In witness whereof, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

ALTRESCO PITTSFIELD, L.P.

By Altresco, Inc.,

Its General Partner.

By _____,

Its _____.

COMMONWEALTH ELECTRIC COMPANY

By _____,

Its President & Chief Operating Officer

17.9 If any provision of this Agreement is found to be prohibited or unenforceable, the remainder of this Agreement shall not be affected thereby and shall be valid and enforceable to the extent permitted by law.

In witness whereof, the parties have caused this Agreement to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

ALTRESCO PITTSFIELD, L.P.

By Altresco, Inc.,

Its General Partner.

By _____,

Its Vice President.

COMMONWEALTH ELECTRIC COMPANY

By _____,

Its _____.

APPENDIX A

DESCRIPTION OF SITE

The Unit is located at the General Electric Plastics and Ordinance Groups' facility in Pittsfield, Massachusetts. The Site Lease and Steam Sale Agreement have been executed with General Electric.

The base plant configuration is a combined cycle power plant featuring three General Electric combustion turbine generators (GTGs), three heat recovery steam generators (HRSGs), a single condensing steam turbine (STG) with water cooled condenser, and supporting systems required for safe, environmentally sound, reliable and economic plant operation.

The supplementary fired HRSGs will supply high pressure superheated steam to the steam turbine to produce a nominal 40 MW of electricity augmenting the nominal 40 MW from each GTG. After subtracting auxiliary loads, the estimated total plant net electrical output is a nominal 160 MW at annual average conditions. Approximately 78,000 lb/hr of 210 psig process steam will be let down from the HRSG high pressure header system and delivered to General Electric's facility.

The cogeneration project occupies approximately 5.0 acres of area within the General Electric facility.

The facility has contracts to supply fuel utilizing a 365-day firm supply of natural gas, with facility requirements at approximately 31.5 million cubic feet per day (MMCFPD).

In the event of an emergency gas supply interruption, the Unit is capable of burning low sulfur distillate fuel oil as a backup fuel.

This Unit has been in commercial operation since August, 1990.

APPENDIX B

1. Total Purchase Price

Each Billing Period, commencing with the Actual In-Service Date, the Company shall pay to the Seller the Total Purchase Price, in accordance with the following formula:

Total Purchase Price = Monthly Capacity Charge + Monthly Energy Charge + Monthly Gas Transportation Demand Cost + Monthly Capital Cost,

> Where Monthly Capacity Charge is defined and computed as set forth in Section 2 of this Appendix B, Monthly Energy Charge is defined and computed as set forth in Section 3 of this Appendix B, Monthly Gas Transportation Demand Cost is defined and computed as set forth in Section 4 of this Appendix B, and Monthly Capital Cost is defined and computed as set forth in Section 5 of this Appendix B; provided, however, that for every Billing Period following the fifteenth (15th) anniversary of the Actual In-Service Date through the remaining term of this Agreement, the Total Purchase Price shall not exceed an amount equal to the sum of (i) the Company's actual avoided costs for the Company's Capacity Entitlement, which avoided costs shall be calculated by the Company, on a per-megawatt (per-MW) basis, and furnished to the Seller prior to such fifteenth (15th) anniversary, plus (ii) the Company's actual avoided cost for the Delivered Energy, as determined pursuant to the Company's effective, generally available Rate P-1 "Power Purchase" rate or any generally available replacement therefor as may be issued by the Company from time to time.

The following definition shall be used in this Appendix B:

Company's Available Kilowatthours shall be equal to the product of (i) the actual Equivalent Availability Factor for the Unit during the applicable Billing Period as calculated in accordance with NEPOOL CRS No. 33, as amended and supplemented from time to time, and as reported in the NEPOOL document entitled "Interim Report for NEPOOL Capability Responsibility"; multiplied by (ii) the Company's Capacity Entitlement; multiplied by (iii) the number of hours in the applicable Billing Period.

2. Monthly Capacity Charge

The Monthly Capacity Charge shall be equal to the product of (i) the Company's Capacity Entitlement; (ii) four dollars and fifty-one cents per kilowatt ($4.51/kW); (iii) an index factor represented by the quantity K/L; and (iv) the Availability Adjustment, defined and computed as set forth in Section 6 of this Appendix B;

> Where K shall be equal to 134.7 through calendar year 1990; and, in each calendar year thereafter, K shall be equal to the Consumer Price Index for Urban Wage Earners and Clerical Workers, unadjusted for seasonal variations, 1982-1984 = 100, all items indexed for Boston, Massachusetts, as published in the Bureau of Labor Statistics' CPI Detailed Report (the "CPI

Index") for November of the preceding calendar year, provided, however, that if a CPI Index is not published for November, then K shall be equal to the CPI Index for the first preceding month for which a CPI Index is published, and

Where L shall be equal to 134.7, which is the CPI Index for November 1989.

3. Monthly Energy Charge

The Monthly Energy Charge shall be equal to the product of (i) the Delivered Energy and (ii) the Kilowatthour Charge:

where the Kilowatthour Charge is equal to the product of (i) one and thirty-six hundredths cents per kilowatthour ($0.0136/kWh) and (ii) an index factor represented by the quantity M/N,

where M shall be equal to the monthly weighted average sum of the following three fuel components, where each is expressed in dollars per MMBtu: (i) 50% weighting for the monthly average of the daily quotes for No. 6 oil (2.2% sulfur) in Platt's Oilgram, Estimated New York Harbor Spot Price, low cargo quotation, assuming 6.3 MMBtu per barrel; (ii) 40% weighting for the Tennessee Gas Pipeline Company's Current Average Cost of Purchased Gas (or its successor rate) as specified in Tennessee Gas Pipeline Company's FERC Gas Tariff; and (iii) 10% weighting for New England Power Company's weighted average delivered cost of coal as reported in the most recently submitted FERC Form 423; and

where N is $2.05/MMBtu.

Commencing on the fifth (5th) anniversary of the Actual In-Service Date pursuant to this Agreement, either the Company or the Seller shall have the right, exercisable not more than once every five years during the remainder of the term of this Agreement, to require renegotiation of the pricing provisions in this Appendix by written notice. The purpose of any such renegotiation shall be to modify Monthly Energy Charge, above, in a manner that will: (i) achieve a price of gas that, taking into account the cost of transportation to the Unit, is competitive with and comparable to the prices of long-term, firm baseload supplies delivered at the city gate to local distribution companies in Connecticut, Massachusetts, and Rhode Island; and (ii) achieve a price of gas that will allow the Unit to be dispatched as a baseload fossil fuel electric generating plant operating at a capacity factor (equal to Net Electric Output divided by the product of the number of hours in a year times the Unit's Design Capacity) of seventy-five percent (75%). In the event the two preceding objectives of any renegotiation are in conflict, the second provision, relating to baseload operation at a seventy-five percent (75%) capacity factor, shall prevail. The Company and the Seller agree that the Kilowatthour Charge shall not be increased or decreased by more than seven and one-half percent (7.5%) at the time of any such renegotiation. The Company and Seller further agree that the base value of the Kilowatthour Charge shall be redefined at the time of any renegotiation in the following manner. In the month following any increase or decrease in the Kilowatthour Charge as a result of renegotiation, the numeric component of the Kilowatthour Charge (i.e., $0.0136 per kilowatthour) shall be set equal to the value of the Kilowatthour Charge for the month in which the value of the Kilowatthour Charge was increased or decreased as a result of the renegotiation. The value of "M" shall be as defined

above. The value of "N" shall be equal to the value of "M" for the month in which the value of the Kilowatthour Charge was increased or decreased as a result of renegotiation.

Notwithstanding the above, in the event that the Seller must operate the Unit under a minimum load level, as described in Article 4.2.2 of this Agreement, the Company shall pay the Seller on a monthly basis, for all kilowatthours produced at such minimum load level (within the limitations set forth in Article 4.2.2), the product of (a) the Delivered Energy, and (b) the Minimum Load Energy Charge, where the Minimum Load Energy Charge shall be the lesser of:

(i) ninety percent (90%) of "G", as defined and calculated in accordance with Article V(B) of New England Power Company's ("NEP") December 9, 1987 Agreement with the Seller with respect to the Unit (the "1987 Agreement"), as amended and as in effect from time to time, or

(ii) "Rate Y", as defined and calculated in accordance with Schedule H of the 1987 Agreement.

At the beginning of each Billing Period, NEP shall calculate and provide to the Company the value of "G" and "Rate Y" for such Billing Period. Such calculations shall be based on the best information available to NEP at the time they are made. Subsequent true-ups to reflect actuals shall not be made.

4. Monthly Gas Transportation Demand Cost

The Monthly Gas Transportation Demand Cost shall be equal to the product of (i) the Company's Available Kilowatthours during the applicable Billing Period, and (ii) the following amounts during each calendar year:

Contract Year		Contract Year	
1992:	$0.0174/kWh	2002:	$0.0201/kWh
1993:	0.0169	2003:	0.0204
1994:	0.0168	2004:	0.0206
1995:	0.0169	2005:	0.0209
1996:	0.0171	2006:	0.0213
1997:	0.0172	2007:	0.0217
1998:	0.0173	2008:	0.0221
1999:	0.0193	2009:	0.0226
2000:	0.0196	2010:	0.0231
2001:	0.0198	2011:	0.0236

5. Monthly Capital Cost

The Monthly Capital Cost shall be equal to the product of (i) the Company's Available Kilowatthours during the applicable Billing Period, and (ii) two and eighteen-hundredths cents per kilowatthour ($0.0218/kWh).

6. Availability Adjustment

Each Billing Period, the Availability Adjustment shall be applied to the Monthly Capacity Charge, based on the ability of the Seller to operate the Unit as measured on a moving, twelve month, cumulative equivalent availability factor basis. The Availability Adjustment shall be determined each Billing Period in accordance with the following:

$$\text{Availability Adjustment} = \frac{EAF}{0.8725};$$

provided, however, that if EAF minus 0.8725 is greater than or equal to -0.05 and less than or equal to +0.05 in the applicable Billing Period, then the Availability Adjustment shall equal 1; and

Where EAF is equal to the moving-average cumulative Equivalent Availability Factor for the Unit for the preceding twelve (12) Billing Periods as calculated in accordance with NEPOOL CRS No. 33, as amended and supplemented from time to time, and as reported in the NEPOOL document entitled "Interim Report for NEPOOL Capability Responsibility"; provided, however, that EAF shall never exceed a value of 1.

7. In the event that any or all of the indices or publications referred to in this Appendix B shall cease to be established or published, the Company and the Seller shall agree upon reasonable substitute indices or publications.

APPENDIX C

LIABILITY INSURANCE

From and after the Actual In-Service Date, the Seller shall take out, carry, and maintain, or cause to be taken out, carried, and maintained, comprehensive general liability insurance, including automobile and contractual liability, and liability arising out of aircraft or watercraft, if applicable, with a combined single limit per occurrence of a least five million dollars ($5,000,000) applicable to bodily injury, sickness or death, and loss of or damage to property, subject to an aggregate limit of not less than five million dollars ($5,000,000) for products and completed operations.

AMENDMENT

TO

POWER SALE AGREEMENT

BETWEEN

COMMONWEALTH ELECTRIC COMPANY

AND

ALTRESCO PITTSFIELD LIMITED PARTNERSHIP

[1A-75]

AMENDMENT TO POWER SALE AGREEMENT
BY AND BETWEEN COMMONWEALTH ELECTRIC COMPANY
AND ALTRESCO PITTSFIELD, L.P.

AMENDMENT dated as of this 7th day of ~~October~~ November, 1994, by and between Commonwealth Electric Company, a Massachusetts corporation with a usual place of business at 2421 Cranberry Highway, Wareham, Massachusetts ("Company") and Altresco Pittsfield, L.P., a Delaware limited partnership with a principal place of business at One Bowdoin Square, Boston, Massachusetts ("Seller"), to the Power Sale Agreement dated February 20, 1992 ("Agreement").

WHEREAS the Company, pursuant to the Agreement and subject specifically to the provisions contained in Article 2.1 of the Agreement, purchases 17.2 percent of the electricity produced by the Seller's electric cogeneration facility, which is capable of generating approximately one-hundred sixty (160) megawatts ("MW") of electricity and which is located at a site owned by General Electric in Pittsfield, Massachusetts (the "Facility" or "Unit"); and

WHEREAS, the Total Purchase Price for electricity purchased by the Company pursuant to Section 1 of Appendix B of the Agreement includes a component known as the Monthly Energy Charge, which component is defined in Section 3 of Appendix B of the Agreement; and

WHEREAS, the Monthly Energy Charge is calculated, in part, by reference to the Tennessee Gas Pipeline Company's ("Tennessee") Current Average Cost of Purchased Gas, also known as the Weighted Average Cost of Gas ("WACOG"), or its successor index, as specified in Tennessee's approved Federal Energy Regulatory Commission ("FERC") Gas Tariff; and

WHEREAS, Tennessee's WACOG ceased to be available as of July, 1992 as a consequence of the restructuring of Tennessee's services pursuant to FERC Order No. 636, and no successor index to Tennessee's WACOG exists; and

WHEREAS, the Company and the Seller have agreed upon the terms of an index to replace Tennessee's WACOG for purposes of calculating the Monthly Energy Charge, and desire to execute this Amendment for purposes of memorializing their agreement.

NOW, THEREFORE, in consideration of the mutual covenants set forth herein, the Company and the Seller agree as follows:

1. Unless otherwise defined herein, capitalized terms shall have the same meaning given to them in the Agreement.

2. For the purposes of determining the Monthly Energy Charge as defined in Section 3 of Appendix B of the Agreement, the first ~~paragraph~~ sentence of said section shall be deleted in its entirety and the following shall be substituted in place thereof:

The Monthly Energy Charge shall be equal to the product of (i) the Delivered Energy and (ii) the Kilowatthour Charge,

where the Kilowatthour Charge is equal to the product of (i) one and thirty-six hundredths cents per kilowatthour ($0.0136/kWh) and (ii) an index factor represented by the quantity M/N,

where M shall be equal to the monthly weighted average sum of the following three fuel components, each expressed in U.S. dollars per MMBtu:

(a) 50% weighting for the monthly average of the daily quotes during the Billing Period for No. 6 residual 2.2% sulfur fuel oil as listed in Platt's Oilgram under the heading "Estimated New York Harbor Spot Price," using the low cargo quotation, and assuming 6.3 MMBtu per barrel; and

(b) 40% weighting for the average of the T2 spot price for each of the twelve (12) months immediately preceding the Billing Period, where the T2 spot price for any month shall be equal to the arithmetic average of the following six indices for such month: the Louisiana & Offshore (zone 1) and Texas (zone 0) indices for Tennessee and the East Louisiana, West Louisiana, East Texas and South Texas indices for the Texas Eastern Transmission Corporation, or their successor indices, each as published in the first of the month edition of Inside F.E.R.C.'s Gas Market Report, by reference to the table entitled "Prices of Spot Gas Delivered to Pipelines...," provided that at least four of the six indices, or their successor indices, are so published for any month, and if at least four of the six indices are not so published for any month, the parties shall determine mutually acceptable substitute indices to use for the calculation of the T2 spot price; and

(c) 10% weighting for New England Power Company's weighted average delivered cost of coal as reported in the most recently submitted FERC Form 423 for New England Power Company from time to time, and

where N is $1.81/MMBtu.

3. The Company shall submit this Amendment to the Massachusetts Department of Public Utilities for approval. This Amendment shall become effective upon the receipt of such approvals in form and substance acceptable to the Company and the Seller.

4. All other terms and conditions of said Agreement shall remain in full force and effect.

IN WITNESS WHEREOF, the Company and the Seller have caused this Amendment to be duly executed as of the day and year first above written.

COMMONWEALTH ELECTRIC COMPANY

By: James J. Keane

Title: Vice President
Power Supply & Transmission

ALTRESCO PITTSFIELD, L.P.
BY JMC ALTRESCO, INC.
ITS GENERAL PARTNER

By: _____

Title: Vice President

SECOND AMENDMENT TO POWER PURCHASE AGREEMENT
BETWEEN COMMONWEALTH ELECTRIC COMPANY AND PITTSFIELD
GENERATING COMPANY, L.P.
DATED FEBRUARY 20, 1992

Second Amendment, dated as of November 22, 1996 to the Power Purchase Agreement dated February 20, 1992, as amended (herein referred to as the "Agreement") between Commonwealth Electric Company, a Massachusetts corporation with offices located at 2421 Cranberry Highway, Wareham, Massachusetts (the "Company") and Pittsfield Generating Company, L.P., formerly known as Altresco Pittsfield, L.P., a Delaware limited partnership with a place of business at One Bowdoin Square, Boston, Massachusetts (the "Seller"). (Unless otherwise stated, all capitalized terms herein are as defined in the Agreement.)

Recitals

(a) This Second Amendment modifies certain terms of the Agreement. The Agreement provides for the sale by the Seller and the purchase by the Company of a 17.2 percent entitlement of the electric capacity and related energy produced by the Unit.

(b) Article 4.1 of the Agreement states in pertinent part: "The unit shall be subject to Economic Dispatch at the direction of the Company or NEPOOL."

(c) Article 6.1 of the Agreement states in pertinent part: "The Seller shall exert all reasonable efforts consistent with Good Utility Practice to cause the Unit to be capable of operating and producing electricity at or near the Design Capacity on a continuous twenty-four (24) hour basis for the full term of this Agreement."

(d) Article 6.3 of the Agreement states in pertinent part: "The Seller may from time-to-time withdraw the Unit from service and cease to supply electric energy to the Company as necessary to perform scheduled or unscheduled maintenance on the Unit."

Accordingly, the Seller and Company, each in consideration of the mutual covenants set forth herein, hereby agree as follows:

SECTION ONE: AMENDMENT TO SECTION 6 of the AGREEMENT

Section 6 of the Agreement shall be amended by adding the following provision:

6.4 Short-term Power Purchases. Seller and Company agree that, from time to time, they may agree to allow and accommodate the short-term purchase by Company of electricity from other market sources in replacement of the purchase of electricity that would otherwise occur pursuant to the Agreement, and that the terms and conditions of such arrangements shall be negotiated on a case-by-case basis and agreed to in writing, but that the Agreement shall otherwise remain in full force and effect.

SECTION TWO: NO OTHER AMENDMENTS OR MODIFICATIONS

All other terms and conditions of the Agreement not specifically amended herein shall remain in full force and effect.

IN WITNESS WHEREOF, the Seller and the Company have caused this Second Amendment to be duly executed as the day and year Second written above.

COMMONWEALTH ELECTRIC COMPANY	PITTSFIELD GENERATING COMPANY, L.P.
By: James J. Keane	By: George J. Grunbach
Its: Vice President - Power Supply & Transmission	Its: Vice President

COMMONWEALTH ELECTRIC COMPANY

Year	Base Case Revenues	Pittsfield Buyout Revenues	Customer Savings
2004	$ 74.654	$ 74.654	$ -
2005	174.902	174.902	$ -
2006	178.400	178.400	$ -
2007	138.764	132.827	$ 5.937
2008	98.448	100.622	$ (2.174)
2009	76.608	76.608	$ -
2010	76.096	76.096	$ -
2011	75.796	75.796	$ -
2012	76.565	76.565	$ -
2013	74.217	74.217	$ -
2014	76.517	76.517	$ -
2015	75.539	75.539	$ -
2016	58.196	58.196	$ -
2017	14.584	14.584	$ -
2018	5.357	5.357	$ -
2019	5.094	5.094	$ -
2020	5.030	5.030	$ -
2021	5.321	5.321	$ -
2022	2.803	2.803	$ -
2023	1.160	1.160	$ -
2024	0.404	0.404	$ -
2025	0.265	0.265	$ -
2026	0.345	0.345	$ -
Total	$ 1,295.065	$ 1,291.302	$ 3.763
NPV	$ 824.156	$ 821.291	$ 2.866
Discount Rate	8.200%		

Discounted at Commonwealth After Tax Discount Rate
used in the Company's Retructuring Filing

Sources:
Col: B from Exhibit NSTAR-CAM-GOL-3, Col.D
Col: C from Exhibit NSTAR-CAM-GOL-4, Col.D
Col: D = Col.B minus Col.D

Commonwealth Electric Company
Transition Charge Calculation
$ in Millions

Year	GWH Delivered	Transition Charge Billed	**Revenues for Delivered GWH**	Total Fixed Component	Total Variable Component	Total Other Adjustment	Prior Year Deferral	Interest on Deferral	**Expenses**	(Over) Under Collection
Col. A	Col. B	Col. C	**Col. D**	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2002										$ 81.510
2003	4,173.546	2.819	**$ 117.657**	$ 0.532	$ 138.189	$ (5.762)	$ 81.510	$ 3.122	**$ 217.591**	99.934
2004	**4,202.750**	**1.776**	**74.654**	**0.494**	**108.669**	**1.589**	**99.934**	**2.638**	**213.324**	**138.670**
2005	4,286.805	4.080	**174.902**	0.458	108.888	2.034	138.670	2.288	**252.338**	77.436
2006	4,372.541	4.080	**178.400**	0.418	120.437	1.915	77.436	1.278	**201.484**	23.084
2007	4,459.992	3.111	**138.764**	0.382	113.006	1.911	23.084	0.381	**138.764**	-
2008	4,549.192	2.164	**98.448**	0.343	96.284	1.821	-	-	**98.448**	-
2009	4,640.176	1.651	**76.608**	0.305	74.357	1.946	-	-	**76.608**	-
2010	4,732.980	1.608	**76.096**	-	74.575	1.521	-	-	**76.096**	-
2011	4,827.640	1.570	**75.796**	-	74.591	1.205	-	-	**75.796**	-
2012	4,924.193	1.555	**76.565**	-	75.523	1.042	-	-	**76.565**	-
2013	5,022.677	1.478	**74.217**	-	73.762	0.455	-	-	**74.217**	-
2014	5,123.131	1.494	**76.517**	-	75.990	0.527	-	-	**76.517**	-
2015	5,225.594	1.446	**75.539**	-	75.025	0.514	-	-	**75.539**	-
2016	5,330.106	1.092	**58.196**	-	57.830	0.366	-	-	**58.196**	-
2017	5,436.708	0.268	**14.584**	-	14.138	0.446	-	-	**14.584**	-
2018	5,545.442	0.097	**5.357**	-	4.923	0.434	-	-	**5.357**	-
2019	5,656.351	0.090	**5.094**	-	4.770	0.324	-	-	**5.094**	-
2020	5,769.478	0.087	**5.030**	-	4.612	0.418	-	-	**5.030**	-
2021	5,884.868	0.090	**5.321**	-	4.908	0.413	-	-	**5.321**	-
2022	6,002.565	0.047	**2.803**	-	2.504	0.299	-	-	**2.803**	-
2023	6,122.616	0.019	**1.160**	-	0.755	0.405	-	-	**1.160**	-
2024	6,245.068	0.006	**0.404**	-	-	0.404	-	-	**0.404**	-
2025	6,369.969	0.004	**0.265**	-	-	0.265	-	-	**0.265**	-
2026	6,497.368	0.005	**0.345**	-	-	0.345	-	-	**0.345**	-

Col. B: 2003 - 12 months actual; 2004 5 months actual, 7 months forecast; years 2005 and beyond assumes 2% growth per annum.
Col. C: 2003 & 2004 = Col. D / Col. B; 2005 & 2006 = Maximum Transition Charge rate; Post 2006 = Col. J / Col. B.
Col. D: 2003 per Page 2, Line 15; 2004 - 2006 = Col. B * Col. C; Post 2006 = Col. J.
Col. E: Page 3, Col. H.
Col. F: Page 4, Col. M.
Col. G: Page 5, Col. L.
Col. H: Col. K prior year.
Col. I: Col. H times interest rate on customer deposits; 2002 ending balance = 3.83%; 2003 ending balance = 2.64%; Post 2003 = 1.65%.
Col. J: Sum Cols. E thru I.
Col. K: 2002 per D.T.E. 02-80B (Settlement); 2003 and later = Col. J - Col. D.

Commonwealth Electric Company
Actual 2003 Transition Revenues
$ in Millions

Line	Description	GWH	A/C #	Per Book $	Total
1	2003 Transition Billed Revenues:				
2	Residential Transition	2,064.405	440160	$ 56.348	
3	Commercial Transition	1,734.871	442500	47.014	
4	Industrial Transition	366.634	442430	9.471	
5	Street Light Transition	16.039	444060	0.437	
6	Total Billed Revenues	4,181.949			**$ 113.270**
7	2003 Transition Unbilled Revenues:			Value	
8	Less: Residential Transition Unbilled @ 12/31/02	(91.151)			
9	Plus: Residential Transition Unbilled @ 12/31/03	87.671	440162	$ 2.145	
10	Less: Industrial Transition Unbilled @ 12/31/02	(18.078)			
11	Plus: Industrial Transition Unbilled @ 12/31/03	16.734	442435	0.360	
12	Less: Commercial Transition Unbilled @ 12/31/02	(81.065)			
13	Plus: Commercial Transition Unbilled @ 12/31/03	77.486	442505	1.882	
14	Total Unbilled Revenues	(8.403)			**4.387**
15	Total 2003 Transition Revenues	4,173.546	2.819		**$ 117.657**

Commonwealth Electric Company
Summary of Transition Charge - Fixed Component
$ in Millions

	Commonwealth Electric Company		Residual Value Credit				
Year	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Commonwealth Generation Recovery/(Proceeds)	Amortization of Commonwealth Generation Recovery/(Proceeds)	Pre-Tax Return on Canal Related Generation Recovery/(Proceeds)	Amortization of Canal Related Generation Recovery/(Proceeds)	Net Fixed Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003	$ 0.103	$ 0.157	$ 0.041	$ 0.114	$ 0.099	$ 0.018	$ 0.532
2004	0.087	0.157	0.034	0.114	0.084	0.018	0.494
2005	0.071	0.157	0.028	0.114	0.070	0.018	0.458
2006	0.055	0.157	0.022	0.114	0.052	0.018	0.418
2007	0.039	0.157	0.015	0.114	0.039	0.018	0.382
2008	0.023	0.157	0.009	0.114	0.022	0.018	0.343
2009	0.008	0.152	0.003	0.110	0.008	0.024	0.305

Note: Amounts per Exhibit COM-JFL-2(DTE 03-118(Supp)).
Col. H = Sum of Columns B through G.

Commonwealth Electric Company
Summary of Transition Charge - Variable Component
$ in Millions

Year	Actual Nuclear Decomm	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Transmission In Support Of Remote Generating Units	Actual Power Contract Buyouts	Actual Payments in Lieu of Property Taxes	Revenue Credits & Damages, Costs, or net Recoveries	Wholesale Credits/Debits	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$ 0.811	$ 207.695	$ 87.684	$ 120.011	$ 1.609	$ 12.461	$ 2.089	$ (0.164)	$ -	$ 1.372	$ -	$ 138.189
2004	1.387	228.753	128.263	100.490	1.700	5.309	1.430	-	-	(0.275)	(1.372)	108.669
2005	1.391	193.719	89.767	103.952	1.895	-	1.375	-	-	-	0.275	108.888
2006	0.350	190.985	73.901	117.084	1.738	-	1.265	-	-	-	-	120.437
2007	0.350	178.157	67.812	110.345	1.651	-	0.660	-	-	-	-	113.006
2008	0.350	161.485	67.296	94.189	1.635	-	0.110	-	-	-	-	96.284
2009	0.350	135.859	63.882	71.977	1.920	-	0.110	-	-	-	-	74.357
2010	0.350	139.106	66.898	72.208	1.907	-	0.110	-	-	-	-	74.575
2011	-	141.971	69.382	72.589	1.892	-	0.110	-	-	-	-	74.591
2012	-	141.492	67.904	73.588	1.880	-	0.055	-	-	-	-	75.523
2013	-	142.495	70.602	71.893	1.869	-	-	-	-	-	-	73.762
2014	-	142.302	68.174	74.128	1.862	-	-	-	-	-	-	75.990
2015	-	143.182	70.024	73.158	1.867	-	-	-	-	-	-	75.025
2016	-	94.418	38.043	56.375	1.455	-	-	-	-	-	-	57.830
2017	-	23.907	11.333	12.574	1.564	-	-	-	-	-	-	14.138
2018	-	7.963	4.643	3.320	1.603	-	-	-	-	-	-	4.923
2019	-	7.963	4.837	3.126	1.644	-	-	-	-	-	-	4.770
2020	-	7.963	5.038	2.925	1.687	-	-	-	-	-	-	4.612
2021	-	7.963	5.245	2.718	2.190	-	-	-	-	-	-	4.908
2022	-	7.963	5.459	2.504	-	-	-	-	-	-	-	2.504
2023	-	2.654	1.899	0.755	-	-	-	-	-	-	-	0.755

Legend:

Col. B: Page 6, Col. E.
Col. C: 2003 - Exhibit COM-JFL-4, Page 3, Line 16(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-COM-GOL-5, Page 3, Line 14.
Col. D: 2003 - Exhibit COM-JFL-4, Page 2, Line 20(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-COM-GOL-5, Page 2, Line 18.
Col. E: Col. C - Col. D.
Col. F: Page 7, Col. G.
Col. G: CPC Lowell buyout payment, 54 months starting December 1999. 2003 includes Seabrook Buyout Adjustment = ($0.280).
Col. H: Commonwealth's 11% share of the Boston Edison Pilgrim property tax liability.
Col. I: Commonwealth's 11% share of the Boston Edison Pilgrim NEIL credit, Maxey Flats payment and DOE/SNF Legal Fees.
Col. K: Exhibit COM-HCL-6.
Col. L: Reversal of Prior Year Rate Design Adjustment (-Col. K(prior year)).
Col. M: Col. B + Col. E + Col. F + Col. G + Col. H + Col. I + Col. J + Col. K + Col. L.

Commonwealth Electric Company
Summary of Transition Charge - Other Adjustments
$ in Millions

					Mitigation Incentive						
Year	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Gain on Sale of Utility Land	Other Adjustment	Hydro Quebec Transmission	Fixed Component (Page 8)	Lowell Cogen. Buyout (Page 9)	Pilgrim Contract Buyout (Page 10)	Seabrook Buydown (Page 11)	Seabrook Buyout (Page 12)	Total Other Adjustments
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$ (7.296)	$ 0.007	$ (0.001)	$ -	$ 0.020	$ 0.237	$ (0.105)	$ 0.670	$ 0.510	$ 0.196	$ (5.762)
2004	-	(0.127)	-	-	0.013	0.231	0.327	0.524	0.496	0.125	1.589
2005	-	-	-	-	0.012	0.226	0.419	0.712	0.483	0.182	2.034
2006	-	-	-	-	0.012	0.221	0.430	0.604	0.468	0.180	1.915
2007	-	-	-	-	0.012	0.216	0.439	0.687	0.456	0.101	1.911
2008	-	-	-	-	0.012	0.211	0.447	0.549	0.441	0.161	1.821
2009	-	-	-	-	-	0.206	0.464	0.677	0.427	0.172	1.946
2010	-	-	-	-	-	-	0.476	0.548	0.414	0.083	1.521
2011	-	-	-	-	-	-	-	0.647	0.400	0.158	1.205
2012	-	-	-	-	-	-	-	0.492	0.385	0.165	1.042
2013	-	-	-	-	-	-	-	-	0.374	0.081	0.455
2014	-	-	-	-	-	-	-	-	0.359	0.168	0.527
2015	-	-	-	-	-	-	-	-	0.345	0.169	0.514
2016	-	-	-	-	-	-	-	-	0.333	0.033	0.366
2017	-	-	-	-	-	-	-	-	0.319	0.127	0.446
2018	-	-	-	-	-	-	-	-	0.303	0.131	0.434
2019	-	-	-	-	-	-	-	-	0.293	0.031	0.324
2020	-	-	-	-	-	-	-	-	0.277	0.141	0.418
2021	-	-	-	-	-	-	-	-	0.262	0.151	0.413
2022	-	-	-	-	-	-	-	-	0.252	0.047	0.299
2023	-	-	-	-	-	-	-	-	0.236	0.169	0.405
2024	-	-	-	-	-	-	-	-	0.219	0.185	0.404
2025	-	-	-	-	-	-	-	-	0.204	0.061	0.265
2026	-	-	-	-	-	-	-	-	0.185	0.160	0.345

Col. B: Amount received from E.I.S. - November 2003.
Col. C: 2003 adjustment to actual of Column I and 4 percent of Seabrook Buyout Adjustment. 2004 forecasted adjustment to Column H.
Col. D: Adjustment to Net Proceeds for Sale of Land at 15 Church Street, Tisbury, MA.
Col. F: Equals 4 percent of Page 7, Col. E.

Commonwealth Electric Company Share of
Summary of Transition Charge - Decommissioning
$ in Millions

Year	Seabrook Unit 1	Seabrook Unit 2	Yankee Atomic	Total
Col. A	Col. B	Col. C	Col. D	Col. E
2003 *	$ -	$ -	$ 0.811	$0.811
2004 **	-	-	1.387	1.387
2005	-	-	1.391	1.391
2006	-	-	0.350	0.350
2007	-	-	0.350	0.350
2008	-	-	0.350	0.350
2009	-	-	0.350	0.350
2010	-	-	0.350	0.350
2011	-	-	-	-
2012	-	-	-	-
2013	-	-	-	-
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	-	-	-	-
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-

* 12 months actual.
** 5 months actual, 7 months forecast.
Note: Col. B & Col. C subject to final reconciliation of sale transaction.

Commonwealth Electric Company
Transmission in Support of Remote Generation
$ in Millions

Year	Seabrook 1	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Wyman 4	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
2003 *	$0.002	$0.299	$1.797	($0.489)	$ -	$1.609
2004 **	-	0.299	1.723	(0.322)	-	1.700
2005	-	0.291	1.904	(0.300)	-	1.895
2006	-	0.153	1.885	(0.300)	-	1.738
2007	-	0.086	1.865	(0.300)	-	1.651
2008	-	0.088	1.847	(0.300)	-	1.635
2009	-	0.091	1.829		-	1.920
2010	-	0.094	1.813		-	1.907
2011	-	0.096	1.796			1.892
2012	-	0.099	1.781			1.880
2013	-	0.102	1.767			1.869
2014	-	0.104	1.758			1.862
2015	-	0.107	1.760			1.867
2016	-	0.111	1.344			1.455
2017	-	0.114	1.450			1.564
2018	-	0.117	1.486			1.603
2019	-	0.121	1.523			1.644
2020	-	0.125	1.562			1.687
2021	-	0.129	2.061			2.190
2022	-					-
2023	-					-
2024	-					-
2025	-					-
2026	-					-

* 12 months actual.
** 5 months actual, 7 months forecast.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Summary - Fixed
$ in Millions

Line		2003	2004	2005	2006	2007	2008	2009
1	Residual Value Credit (Debit):							
2	Commonwealth (Exhibit 2, Page 3, Line 33) Total Proceeds	($0.155)	($0.148)	($0.142)	($0.136)	($0.129)	($0.123)	($0.113)
3	Canal (Exhibit 2, Page 4, Line 29) Excess Proceeds	32.707	31.921	31.134	30.348	29.561	28.775	27.986
4	Commonwealth (Exhibit 2, Page 5, Line 6) Pilgrim Buyout	(11.448)	(11.173)	(10.898)	(10.621)	(10.346)	(10.071)	(9.802)
5	Commonwealth (Exhibit 2, Page 10, Line 29) PREA Buyout	(0.248)	(0.242)	(0.236)	(0.230)	(0.225)	(0.219)	(0.208)
6	Commonwealth (Exhibit 2, Page 11, Line 29) Seabrook Buydown	(14.681)	(14.328)	(13.975)	(13.622)	(13.269)	(12.915)	(12.563)
7	Total	6.175	6.030	5.883	5.739	5.592	5.447	5.300
8								
9	Less - Owned Generation per Compliance Filing:							
10	Commonwealth (Exhibit 2, Page 2, Line 28) Embedded Cost	0.260	0.244	0.228	0.212	0.196	0.180	0.160
11								
12	Net Incremental Gain on Sale of Owned Gen (L7 - L10)	5.915	5.786	5.655	5.527	5.396	5.267	5.140
13								
14	Transition Charge Mitigation Incentive Mechanism @ 4%	$0.237	$0.231	$0.226	$0.221	$0.216	$0.211	$0.206

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Lowell Cogen Buyout
$ in Millions

	Original Forecast			Revised Forecast				
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2003	$13.384	$3.264	$10.120	$12.741	($2.621)	($0.105)	4,173.546	(0.00252)
2004	13.685	3.379	10.306	2.124	8.182	0.327	4,202.750	0.00778
2005	14.015	3.528	10.487		10.487	0.419	4,286.805	0.00977
2006	14.368	3.626	10.742		10.742	0.430	4,372.541	0.00983
2007	14.747	3.767	10.980		10.980	0.439	4,459.992	0.00984
2008	15.145	3.963	11.182		11.182	0.447	4,549.192	0.00983
2009	15.576	3.967	11.609		11.609	0.464	4,640.176	0.01000
2010	16.031	4.138	11.893		11.893	0.476	4,732.980	0.01006

Column Notes:

Col. B: See DTE 98-78, Schedule 1, Page 11, Column (8).
Col. C: See DTE 98-78, Schedule 1, Page 12, Column (8) times NERA Base Load Market Forecast.
Col. D: Col. B - Col. C.
Col. E: See DTE 99-65 for revised amounts
Col. F: Col. D - Col. E.
Col. G: Col. F Multiplied by 4%.
Col. H: 2003- 2010, see Page 1, Col. B.
Col. I: Col. G/Col. H Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Pilgrim Contract Buyout
$ in Millions

	Original Forecast					Revised Forecast						
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Filed Case	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$3.836	$33.707	$18.883	$14.824	$18.660	$11.238	$9.325	$1.913	$16.747	$0.670	4,173.546	0.01605
2004	3.951	33.861	21.842	12.019	15.970	13.718	10.859	2.859	13.111	0.524	4,202.750	0.01247
2005	4.069	34.135	20.405	13.730	17.799			-	17.799	0.712	4,286.805	0.01661
2006	4.191	34.339	23.437	10.902	15.093			-	15.093	0.604	4,372.541	0.01381
2007	4.317	34.655	21.791	12.864	17.181			-	17.181	0.687	4,459.992	0.01540
2008	4.447	34.907	25.617	9.290	13.737			-	13.737	0.549	4,549.192	0.01207
2009	4.580	35.300	22.947	12.353	16.933			-	16.933	0.677	4,640.176	0.01459
2010	4.717	35.733	26.744	8.989	13.706			-	13.706	0.548	4,732.980	0.01158
2011	4.859	36.082	24.756	11.326	16.185			-	16.185	0.647	4,827.640	0.01340
2012	5.005	35.327	28.024	7.303	12.308			-	12.308	0.492	4,924.193	0.00999

Column Notes:

Col. B: Restated per new Pilgrim decommissioning forecast in DTE 98-126.
Col. C: See DTE 98-78, Schedule 1, Page 11, Column (1).
Col. D: See DTE 98-78, Schedule 1, Page 12, Column (1) times NERA Base Load Market Forecast.
Col. E: Col. C - Col. D.
Col. F: Col. B + Col. E.
See DTE 98-126 for revised amounts for Cols. G through I.
Col. J: Col. F - Col. I.
Col. K: Col. J Multiplied by 4%.
Col. L: 2003 - 2012, see Page 1, Col. B.
Col. M: Col. K/Col. L Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buydown
$ in Millions

	Original Forecast			Revised Forecast				Transition		
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$25.689	$8.813	$16.876	$12.950	$8.813	$4.137	$12.739	$0.510	4,173.546	0.01222
2004	24.848	10.091	14.757	12.438	10.091	2.347	12.410	0.496	4,202.750	0.01180
2005	25.333	9.523	15.810	13.267	9.523	3.744	12.066	0.483	4,286.805	0.01127
2006	25.170	9.789	15.381	13.472	9.789	3.683	11.698	0.468	4,372.541	0.01070
2007	24.321	11.249	13.072	12.927	11.249	1.678	11.394	0.456	4,459.992	0.01022
2008	24.889	10.700	14.189	13.862	10.700	3.162	11.027	0.441	4,549.192	0.00969
2009	24.779	10.709	14.070	14.103	10.709	3.394	10.676	0.427	4,640.176	0.00920
2010	23.871	12.355	11.516	13.514	12.355	1.159	10.357	0.414	4,732.980	0.00875
2011	24.569	11.554	13.015	14.559	11.554	3.005	10.010	0.400	4,827.640	0.00829
2012	24.473	11.705	12.768	14.840	11.705	3.135	9.633	0.385	4,924.193	0.00782
2013	23.551	13.184	10.367	14.204	13.184	1.020	9.347	0.374	5,022.677	0.00745
2014	24.355	12.242	12.113	15.381	12.242	3.139	8.974	0.359	5,123.131	0.00701
2015	24.331	12.564	11.767	15.715	12.564	3.151	8.616	0.345	5,225.594	0.00660
2016	23.343	14.310	9.033	15.027	14.310	0.717	8.316	0.333	5,330.106	0.00625
2017	24.310	13.316	10.994	16.347	13.316	3.031	7.963	0.319	5,436.708	0.00587
2018	24.315	13.589	10.726	16.739	13.589	3.150	7.576	0.303	5,545.442	0.00546
2019	23.302	15.336	7.966	15.987	15.336	0.651	7.315	0.293	5,656.351	0.00518
2020	24.414	14.094	10.320	17.489	14.094	3.395	6.925	0.277	5,769.478	0.00480
2021	24.524	14.329	10.195	17.974	14.329	3.645	6.550	0.262	5,884.868	0.00445
2022	23.461	16.126	7.335	17.165	16.126	1.039	6.296	0.252	6,002.565	0.00420
2023	24.818	14.834	9.984	18.916	14.834	4.082	5.902	0.236	6,122.616	0.00385
2024	25.055	15.100	9.955	19.585	15.100	4.485	5.470	0.219	6,245.068	0.00351
2025	23.479	16.998	6.481	18.376	16.998	1.378	5.103	0.204	6,369.969	0.00320
2026	24.106	15.639	8.467	19.474	15.639	3.835	4.632	0.185	6,497.368	0.00285

Column Notes:

Col. B: See DTE 98-78, Schedule 1, Page 11, Column (2).
Col. C: See DTE 98-78, Schedule 1, Page 12, Column (2) times NERA Base Load Market Forecast.
Col. D: Col. B - Col. C.
See DTE 99-89 for revised amounts for Cols. E through G.
Col. H: Col. D - Col. G.
Col. I: Col. H Multiplied by 4%.
Col. J: 2003 - 2026, see Page 1, Col. B.
Col. K: Col. I/Col. J Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buyout
$ in Millions

	Original Forecast						Revised Forecast				
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Transmission in Support of Remote Generation	Total Filed Case	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$0.565	$12.950	$8.813	$4.137	$0.186	$4.888	$ -	$4.888	$0.196	4,173.546	0.00470
2004	0.588	12.438	10.091	2.347	0.184	3.119		3.119	0.125	4,202.750	0.00297
2005	0.614	13.267	9.523	3.744	0.182	4.540		4.540	0.182	4,286.805	0.00425
2006	0.639	13.472	9.789	3.683	0.180	4.502		4.502	0.180	4,372.541	0.00412
2007	0.666	12.927	11.249	1.678	0.178	2.522		2.522	0.101	4,459.992	0.00226
2008	0.695	13.862	10.700	3.162	0.175	4.032		4.032	0.161	4,549.192	0.00354
2009	0.723	14.103	10.709	3.394	0.173	4.290		4.290	0.172	4,640.176	0.00371
2010	0.754	13.514	12.355	1.159	0.171	2.084		2.084	0.083	4,732.980	0.00175
2011	0.785	14.559	11.554	3.005	0.169	3.959		3.959	0.158	4,827.640	0.00327
2012	0.819	14.840	11.705	3.135	0.167	4.121		4.121	0.165	4,924.193	0.00335
2013	0.852	14.204	13.184	1.020	0.165	2.037		2.037	0.081	5,022.677	0.00161
2014	0.888	15.381	12.242	3.139	0.163	4.190		4.190	0.168	5,123.131	0.00328
2015	0.924	15.715	12.564	3.151	0.161	4.236		4.236	0.169	5,225.594	0.00323
2016	(0.014)	15.027	14.310	0.717	0.111	0.814		0.814	0.033	5,330.106	0.00062
2017	(0.013)	16.347	13.316	3.031	0.145	3.163		3.163	0.127	5,436.708	0.00234
2018	(0.013)	16.739	13.589	3.150	0.145	3.282		3.282	0.131	5,545.442	0.00236
2019	(0.011)	15.987	15.336	0.651	0.146	0.786		0.786	0.031	5,656.351	0.00055
2020	(0.011)	17.489	14.094	3.395	0.147	3.531		3.531	0.141	5,769.478	0.00244
2021	(0.010)	17.974	14.329	3.645	0.148	3.783		3.783	0.151	5,884.868	0.00257
2022	(0.009)	17.165	16.126	1.039	0.149	1.179		1.179	0.047	6,002.565	0.00078
2023	(0.007)	18.916	14.834	4.082	0.151	4.226		4.226	0.169	6,122.616	0.00276
2024	(0.007)	19.585	15.100	4.485	0.155	4.633		4.633	0.185	6,245.068	0.00296
2025	(0.006)	18.376	16.998	1.378	0.157	1.529		1.529	0.061	6,369.969	0.00096
2026	(0.004)	19.474	15.639	3.835	0.159	3.990		3.990	0.160	6,497.368	0.00246

Column Notes:

Col. B: See DTE 01-79, Exhibit COM-BKR-1, Page 6, Columns B & C.
Col. C: See Page 11, Column E.
Col. D: See Page 11, Column F.
Col. E: Col. C - Col. D.
Col. F: See DTE 99-90, Schedule 1, Page 7, Column (2).
Col. G: Col. B + Col. E + Col. F.
Col. H: Estimated Buyout Amount per DTE 02-34.
Col. I: Col. G - Col. H.
Col. J: Col. I Multiplied by 4%.
Col. K: See Page 1, Col. B.
Col. L: Col. J/Col. K Multiplied by 100.

Commonwealth Electric Company
Power Contract Obligations
Annual Obligations in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
Jan - Mar														
Apr - May														
Jun - Sep														
Oct - Dec														
2004														
Jan - Feb														
Mar														
Apr - Dec														
2005														
2006														
2007														
2008														
2009														
2010														
2011														
2012														
2013														
2014														
2015														
2016														
2017														
2018														
2019														
2020														
2021														
2022														
2023														

REDACTED

Note: Updated from COM-JFL-3 (supp) in D.T.E. 03-118 with latest forecast from CEA.

Commonwealth Electric Company
Power Contract Obligations
Annual Market in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P
Jan - Mar															
Apr - May															
Jun - Sep															
Oct - Dec															
2004															
Jan - Feb															
Mar															
Apr - Dec															
2005															
2006															
2007															
2008															
2009															
2010															
2011															
2012															
2013															
2014															
2015															
2016															
2017															
2018															
2019															
2020															
2021															
2022															
2023															

REDACTED

Note: Cols B thru N are updated from CAM-JFL-3 (supp) in D.T.E. 03-118 with latest forecast from CEA.
Col.O = Col.P minus Cols. B thru N for Jan 2004 through Feb 2005
Col.P for Jan 2004 through Feb 2005 (Standard Offer period) is equal to the transfer price from NSTAR-GOL-5 & 7 (page 1, line 7)
Col.P for March 2005 onwards = sum Col. B thru Col. N

Commonwealth Electric Company
Power Contract Obligations
Annual Above Market in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O	Col. P
Jan - Mar															
Apr - May															
Jun - Sep															
Oct - Dec															
2004															
Jan - Feb															
Mar															
Apr - Dec															
2005															
2006															
2007															
2008															
2009															
2010															
2011															
2012															
2013															
2014															
2015															
2016															
2017															
2018															
2019															
2020															
2021															
2022															
2023															

REDACTED

Note: Annual above Market = Annual Obligation (p.13) minus Annual Market (p.14)

Commonwealth Electric Company
Transition Charge Calculation
$ in Millions

Year	GWH Delivered	Transition Charge Billed	**Revenues for Delivered GWH**	Total Fixed Component	Total Variable Component	Total Other Adjustment	Prior Year Deferral	Interest on Deferral	**Expenses**	(Over) Under Collection
Col. A	Col. B	Col. C	**Col. D**	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2002										$ 81.510
2003	4,173.546	2.819	**$ 117.657**	$ 0.532	$ 138.189	$ (5.762)	$ 81.510	$ 3.122	**$ 217.591**	99.934
2004	**4,202.750**	**1.776**	**74.654**	**0.494**	**108.550**	**1.754**	**99.934**	**2.638**	**213.370**	**138.716**
2005	4,286.805	4.080	**174.902**	0.458	102.129	2.034	138.716	2.289	**245.626**	70.724
2006	4,372.541	4.080	**178.400**	0.418	123.146	1.915	70.724	1.167	**197.370**	18.970
2007	4,459.992	2.978	**132.827**	0.382	111.251	1.911	18.970	0.313	**132.827**	-
2008	4,549.192	2.212	**100.622**	0.343	98.458	1.821	-	-	**100.622**	-
2009	4,640.176	1.651	**76.608**	0.305	74.357	1.946	-	-	**76.608**	-
2010	4,732.980	1.608	**76.096**	-	74.575	1.521	-	-	**76.096**	-
2011	4,827.640	1.570	**75.796**	-	74.591	1.205	-	-	**75.796**	-
2012	4,924.193	1.555	**76.565**	-	75.523	1.042	-	-	**76.565**	-
2013	5,022.677	1.478	**74.217**	-	73.762	0.455	-	-	**74.217**	-
2014	5,123.131	1.494	**76.517**	-	75.990	0.527	-	-	**76.517**	-
2015	5,225.594	1.446	**75.539**	-	75.025	0.514	-	-	**75.539**	-
2016	5,330.106	1.092	**58.196**	-	57.830	0.366	-	-	**58.196**	-
2017	5,436.708	0.268	**14.584**	-	14.138	0.446	-	-	**14.584**	-
2018	5,545.442	0.097	**5.357**	-	4.923	0.434	-	-	**5.357**	-
2019	5,656.351	0.090	**5.094**	-	4.770	0.324	-	-	**5.094**	-
2020	5,769.478	0.087	**5.030**	-	4.612	0.418	-	-	**5.030**	-
2021	5,884.868	0.090	**5.321**	-	4.908	0.413	-	-	**5.321**	-
2022	6,002.565	0.047	**2.803**	-	2.504	0.299	-	-	**2.803**	-
2023	6,122.616	0.019	**1.160**	-	0.755	0.405	-	-	**1.160**	-
2024	6,245.068	0.006	**0.404**	-	-	0.404	-	-	**0.404**	-
2025	6,369.969	0.004	**0.265**	-	-	0.265	-	-	**0.265**	-
2026	6,497.368	0.005	**0.345**	-	-	0.345	-	-	**0.345**	-

Col. B: 2003 - 12 months actual; 2004 5 months actual, 7 months forecast; years 2005 and beyond assumes 2% growth per annum.
Col. C: 2003 & 2004 = Col. D / Col. B; 2005 & 2006 = Maximum Transition Charge rate; Post 2006 = Col. J / Col. B.
Col. D: 2003 per Page 2, Line 15; 2004 - 2006 = Col. B * Col. C; Post 2006 = Col. J.
Col. E: Page 3, Col. H.
Col. F: Page 4, Col. M.
Col. G: Page 5, Col. L.
Col. H: Col. K prior year.
Col. I: Col. H times interest rate on customer deposits; 2002 ending balance = 3.83%; 2003 ending balance = 2.64%; Post 2003 = 1.65%.
Col. J: Sum Cols. E thru I.
Col. K: 2002 per D.T.E. 02-80B (Settlement); 2003 and later = Col. J - Col. D.

Commonwealth Electric Company
Actual 2003 Transition Revenues
$ in Millions

Line	Description	GWH	A/C #	Per Book $	Total
1	2003 Transition Billed Revenues:				
2	Residential Transition	2,064.405	440160	$ 56.348	
3	Commercial Transition	1,734.871	442500	47.014	
4	Industrial Transition	366.634	442430	9.471	
5	Street Light Transition	16.039	444060	0.437	
6	Total Billed Revenues	4,181.949			**$ 113.270**
7	2003 Transition Unbilled Revenues:			Value	
8	Less: Residential Transition Unbilled @ 12/31/02	(91.151)			
9	Plus: Residential Transition Unbilled @ 12/31/03	87.671	440162	$ 2.145	
10	Less: Industrial Transition Unbilled @ 12/31/02	(18.078)			
11	Plus: Industrial Transition Unbilled @ 12/31/03	16.734	442435	0.360	
12	Less: Commercial Transition Unbilled @ 12/31/02	(81.065)			
13	Plus: Commercial Transition Unbilled @ 12/31/03	77.486	442505	1.882	
14	Total Unbilled Revenues	(8.403)			**4.387**
15	Total 2003 Transition Revenues	4,173.546	2.819		**$ 117.657**

Commonwealth Electric Company
Summary of Transition Charge - Fixed Component
$ in Millions

	Commonwealth Electric Company		Residual Value Credit				
Year	Pre-Tax Return on Generation Related Assets	Amortization of Generation Related Assets	Pre-Tax Return on Commonwealth Generation Recovery/(Proceeds)	Amortization of Commonwealth Generation Recovery/(Proceeds)	Pre-Tax Return on Canal Related Generation Recovery/(Proceeds)	Amortization of Canal Related Generation Recovery/(Proceeds)	Net Fixed Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H
2003	$ 0.103	$ 0.157	$ 0.041	$ 0.114	$ 0.099	$ 0.018	$ 0.532
2004	0.087	0.157	0.034	0.114	0.084	0.018	0.494
2005	0.071	0.157	0.028	0.114	0.070	0.018	0.458
2006	0.055	0.157	0.022	0.114	0.052	0.018	0.418
2007	0.039	0.157	0.015	0.114	0.039	0.018	0.382
2008	0.023	0.157	0.009	0.114	0.022	0.018	0.343
2009	0.008	0.152	0.003	0.110	0.008	0.024	0.305

Note: Amounts per Exhibit COM-JFL-2(DTE 03-118(Supp)).
Col. H = Sum of Columns B through G.

Commonwealth Electric Company
Summary of Transition Charge - Variable Component
$ in Millions

Year	Actual Nuclear Decomm	Actual Power Total Obligations	Actual Power Contracts Market Value	Net Power Obligation	Actual Transmission In Support Of Remote Generating Units	Actual Power Contract Buyouts	Actual Payments in Lieu of Property Taxes	Revenue Credits & Damages, Costs, or net Recoveries	Wholesale Credits/Debits	Rate Design Adjustment	Reversal of Prior Year Rate Design Adjustment	Actual Total Variable Component
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$ 0.811	$ 207.695	$ 87.684	$ 120.011	$ 1.609	$ 12.461	$ 2.089	$ (0.164)	$ -	$ 1.372	$ -	$ 138.189
2004	1.387	227.146	126.775	100.371	1.700	5.309	1.430	-	-	(0.275)	(1.372)	108.550
2005	1.391	183.068	85.875	97.193	1.895	-	1.375	-	-	-	0.275	102.129
2006	0.350	190.348	70.555	119.793	1.738	-	1.265	-	-	-	-	123.146
2007	0.350	173.264	64.674	108.590	1.651	-	0.660	-	-	-	-	111.251
2008	0.350	160.421	64.058	96.363	1.635	-	0.110	-	-	-	-	98.458
2009	0.350	132.524	60.547	71.977	1.920	-	0.110	-	-	-	-	74.357
2010	0.350	135.614	63.406	72.208	1.907	-	0.110	-	-	-	-	74.575
2011	-	138.339	65.750	72.589	1.892	-	0.110	-	-	-	-	74.591
2012	-	141.492	67.904	73.588	1.880	-	0.055	-	-	-	-	75.523
2013	-	142.495	70.602	71.893	1.869	-	-	-	-	-	-	73.762
2014	-	142.302	68.174	74.128	1.862	-	-	-	-	-	-	75.990
2015	-	143.182	70.024	73.158	1.867	-	-	-	-	-	-	75.025
2016	-	94.418	38.043	56.375	1.455	-	-	-	-	-	-	57.830
2017	-	23.907	11.333	12.574	1.564	-	-	-	-	-	-	14.138
2018	-	7.963	4.643	3.320	1.603	-	-	-	-	-	-	4.923
2019	-	7.963	4.837	3.126	1.644	-	-	-	-	-	-	4.770
2020	-	7.963	5.038	2.925	1.687	-	-	-	-	-	-	4.612
2021	-	7.963	5.245	2.718	2.190	-	-	-	-	-	-	4.908
2022	-	7.963	5.459	2.504	-	-	-	-	-	-	-	2.504
2023	-	2.654	1.899	0.755	-	-	-	-	-	-	-	0.755

Legend:

Col. B:	Page 6, Col. E.
Col. C:	2003 - Exhibit COM-JFL-4, Page 3, Line 16(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-COM-GOL-6, Page 3, Line 14.
Col. D:	2003 - Exhibit COM-JFL-4, Page 2, Line 20(DTE 03-118(Supp)); 2004 - Exhibit NSTAR-COM-GOL-6, Page 2, Line 19.
Col. E:	Col. C - Col. D.
Col. F:	Page 7, Col. G.
Col. G:	CPC Lowell buyout payment, 54 months starting December 1999. 2003 includes Seabrook Buyout Adjustment = ($0.280).
Col. H:	Commonwealth's 11% share of the Boston Edison Pilgrim property tax liability.
Col. I:	Commonwealth's 11% share of the Boston Edison Pilgrim NEIL credit, Maxey Flats payment and DOE/SNF Legal Fees.
Col. K:	Exhibit COM-HCL-6.
Col. L:	Reversal of Prior Year Rate Design Adjustment (-Col. K(prior year)).
Col. M:	Col. B + Col. E + Col. F + Col. G + Col. H + Col. I + Col. J + Col. K + Col. L.

Commonwealth Electric Company
Summary of Transition Charge - Other Adjustments
$ in Millions

Year	EIS Return on Investment Adjustment	Mitigation Incentive Adjustment	Gain on Sale of Utility Land	Other Adjustment	Mitigation Incentive: Hydro Quebec Transmission	Mitigation Incentive: Fixed Component (Page 8)	Mitigation Incentive: Lowell Cogen. Buyout (Page 9)	Mitigation Incentive: Pilgrim Contract Buyout (Page 10)	Mitigation Incentive: Seabrook Buydown (Page 11)	Mitigation Incentive: Seabrook Buyout (Page 12)	Total Other Adjustments
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$ (7.296)	$ 0.007	$ (0.001)	$ -	$ 0.020	$ 0.237	$ (0.105)	$ 0.670	$ 0.510	$ 0.196	$ (5.762)
2004	-	0.038	-	-	0.013	0.231	0.327	0.524	0.496	0.125	1.754
2005	-	-	-	-	0.012	0.226	0.419	0.712	0.483	0.182	2.034
2006	-	-	-	-	0.012	0.221	0.430	0.604	0.468	0.180	1.915
2007	-	-	-	-	0.012	0.216	0.439	0.687	0.456	0.101	1.911
2008	-	-	-	-	0.012	0.211	0.447	0.549	0.441	0.161	1.821
2009	-	-	-	-	-	0.206	0.464	0.677	0.427	0.172	1.946
2010	-	-	-	-	-	-	0.476	0.548	0.414	0.083	1.521
2011	-	-	-	-	-	-	-	0.647	0.400	0.158	1.205
2012	-	-	-	-	-	-	-	0.492	0.385	0.165	1.042
2013	-	-	-	-	-	-	-	-	0.374	0.081	0.455
2014	-	-	-	-	-	-	-	-	0.359	0.168	0.527
2015	-	-	-	-	-	-	-	-	0.345	0.169	0.514
2016	-	-	-	-	-	-	-	-	0.333	0.033	0.366
2017	-	-	-	-	-	-	-	-	0.319	0.127	0.446
2018	-	-	-	-	-	-	-	-	0.303	0.131	0.434
2019	-	-	-	-	-	-	-	-	0.293	0.031	0.324
2020	-	-	-	-	-	-	-	-	0.277	0.141	0.418
2021	-	-	-	-	-	-	-	-	0.262	0.151	0.413
2022	-	-	-	-	-	-	-	-	0.252	0.047	0.299
2023	-	-	-	-	-	-	-	-	0.236	0.169	0.405
2024	-	-	-	-	-	-	-	-	0.219	0.185	0.404
2025	-	-	-	-	-	-	-	-	0.204	0.061	0.265
2026	-	-	-	-	-	-	-	-	0.185	0.160	0.345

Col. B: Amount received from E.I.S. - November 2003.
Col. C: 2003 adjustment to actual of Column I and 4 percent of Seabrook Buyout Adjustment.
2004 forecasted adjustment to Column H and NPV of 4% of Altresco-Pittfield saving (page 16, column G).
Col. D: Adjustment to Net Proceeds for Sale of Land at 15 Church Street, Tisbury, MA.
Col. F: Equals 4 percent of Page 7, Col. E.

Commonwealth Electric Company Share of
Summary of Transition Charge - Decommissioning
$ in Millions

Year	Seabrook Unit 1	Seabrook Unit 2	Yankee Atomic	Total
Col. A	Col. B	Col. C	Col. D	Col. E
2003 *	$ -	$ -	$ 0.811	$0.811
2004 **	-	-	1.387	1.387
2005	-	-	1.391	1.391
2006	-	-	0.350	0.350
2007	-	-	0.350	0.350
2008	-	-	0.350	0.350
2009	-	-	0.350	0.350
2010	-	-	0.350	0.350
2011	-	-	-	-
2012	-	-	-	-
2013	-	-	-	-
2014	-	-	-	-
2015	-	-	-	-
2016	-	-	-	-
2017	-	-	-	-
2018	-	-	-	-
2019	-	-	-	-
2020	-	-	-	-
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-

* 12 months actual.
** 5 months actual, 7 months forecast.
Note: Col. B & Col. C subject to final reconciliation of sale transaction.

Commonwealth Electric Company
Transmission in Support of Remote Generation
$ in Millions

Year	Seabrook 1	Hydro Quebec Phase 1	Hydro Quebec Phase 2	Hydro Quebec Mitigation	Wyman 4	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G
2003 *	$0.002	$0.299	$1.797	($0.489)	$ -	$1.609
2004 **	-	0.299	1.723	(0.322)	-	1.700
2005	-	0.291	1.904	(0.300)	-	1.895
2006	-	0.153	1.885	(0.300)	-	1.738
2007	-	0.086	1.865	(0.300)	-	1.651
2008	-	0.088	1.847	(0.300)	-	1.635
2009	-	0.091	1.829		-	1.920
2010	-	0.094	1.813		-	1.907
2011	-	0.096	1.796			1.892
2012	-	0.099	1.781			1.880
2013	-	0.102	1.767			1.869
2014	-	0.104	1.758			1.862
2015	-	0.107	1.760			1.867
2016	-	0.111	1.344			1.455
2017	-	0.114	1.450			1.564
2018	-	0.117	1.486			1.603
2019	-	0.121	1.523			1.644
2020	-	0.125	1.562			1.687
2021	-	0.129	2.061			2.190
2022	-					-
2023	-					-
2024	-					-
2025	-					-
2026	-					-

* 12 months actual.
** 5 months actual, 7 months forecast.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Summary - Fixed
$ in Millions

Line		2003	2004	2005	2006	2007	2008	2009
1	Residual Value Credit (Debit):							
2	Commonwealth (Exhibit 2, Page 3, Line 33) Total Proceeds	($0.155)	($0.148)	($0.142)	($0.136)	($0.129)	($0.123)	($0.113)
3	Canal (Exhibit 2, Page 4, Line 29) Excess Proceeds	32.707	31.921	31.134	30.348	29.561	28.775	27.986
4	Commonwealth (Exhibit 2, Page 5, Line 6) Pilgrim Buyout	(11.448)	(11.173)	(10.898)	(10.621)	(10.346)	(10.071)	(9.802)
5	Commonwealth (Exhibit 2, Page 10, Line 29) PREA Buyout	(0.248)	(0.242)	(0.236)	(0.230)	(0.225)	(0.219)	(0.208)
6	Commonwealth (Exhibit 2, Page 11, Line 29) Seabrook Buydown	(14.681)	(14.328)	(13.975)	(13.622)	(13.269)	(12.915)	(12.563)
7	Total	6.175	6.030	5.883	5.739	5.592	5.447	5.300
8								
9	Less - Owned Generation per Compliance Filing:							
10	Commonwealth (Exhibit 2, Page 2, Line 28) Embedded Cost	0.260	0.244	0.228	0.212	0.196	0.180	0.160
11								
12	Net Incremental Gain on Sale of Owned Gen (L7 - L10)	5.915	5.786	5.655	5.527	5.396	5.267	5.140
13								
14	Transition Charge Mitigation Incentive Mechanism @ 4%	$0.237	$0.231	$0.226	$0.221	$0.216	$0.211	$0.206

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Lowell Cogen Buyout
$ in Millions

	Original Forecast			Revised Forecast				
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2003	$13.384	$3.264	$10.120	$12.741	($2.621)	($0.105)	4,173.546	(0.00252)
2004	13.685	3.379	10.306	2.124	8.182	0.327	4,202.750	0.00778
2005	14.015	3.528	10.487		10.487	0.419	4,286.805	0.00977
2006	14.368	3.626	10.742		10.742	0.430	4,372.541	0.00983
2007	14.747	3.767	10.980		10.980	0.439	4,459.992	0.00984
2008	15.145	3.963	11.182		11.182	0.447	4,549.192	0.00983
2009	15.576	3.967	11.609		11.609	0.464	4,640.176	0.01000
2010	16.031	4.138	11.893		11.893	0.476	4,732.980	0.01006

Column Notes:

Col. B: See DTE 98-78, Schedule 1, Page 11, Column (8).
Col. C: See DTE 98-78, Schedule 1, Page 12, Column (8) times NERA Base Load Market Forecast.
Col. D: Col. B - Col. C.
Col. E: See DTE 99-65 for revised amounts
Col. F: Col. D - Col. E.
Col. G: Col. F Multiplied by 4%.
Col. H: 2003- 2010, see Page 1, Col. B.
Col. I: Col. G/Col. H Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Pilgrim Contract Buyout
$ in Millions

	Original Forecast					Revised Forecast						
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Filed Case	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M
2003	$3.836	$33.707	$18.883	$14.824	$18.660	$11.238	$9.325	$1.913	$16.747	$0.670	4,173.546	0.01605
2004	3.951	33.861	21.842	12.019	15.970	13.718	10.859	2.859	13.111	0.524	4,202.750	0.01247
2005	4.069	34.135	20.405	13.730	17.799			-	17.799	0.712	4,286.805	0.01661
2006	4.191	34.339	23.437	10.902	15.093			-	15.093	0.604	4,372.541	0.01381
2007	4.317	34.655	21.791	12.864	17.181			-	17.181	0.687	4,459.992	0.01540
2008	4.447	34.907	25.617	9.290	13.737			-	13.737	0.549	4,549.192	0.01207
2009	4.580	35.300	22.947	12.353	16.933			-	16.933	0.677	4,640.176	0.01459
2010	4.717	35.733	26.744	8.989	13.706			-	13.706	0.548	4,732.980	0.01158
2011	4.859	36.082	24.756	11.326	16.185			-	16.185	0.647	4,827.640	0.01340
2012	5.005	35.327	28.024	7.303	12.308			-	12.308	0.492	4,924.193	0.00999

Column Notes:

Col. B: Restated per new Pilgrim decommissioning forecast in DTE 98-126.
Col. C: See DTE 98-78, Schedule 1, Page 11, Column (1).
Col. D: See DTE 98-78, Schedule 1, Page 12, Column (1) times NERA Base Load Market Forecast.
Col. E: Col. C - Col. D.
Col. F: Col. B + Col. E.
See DTE 98-126 for revised amounts for Cols. G through I.
Col. J: Col. F - Col. I.
Col. K: Col. J Multiplied by 4%.
Col. L: 2003 - 2012, see Page 1, Col. B.
Col. M: Col. K/Col. L Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buydown
$ in Millions

	Original Forecast			Revised Forecast				Transition		
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Total Mitigation	Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K
2003	$25.689	$8.813	$16.876	$12.950	$8.813	$4.137	$12.739	$0.510	4,173.546	0.01222
2004	24.848	10.091	14.757	12.438	10.091	2.347	12.410	0.496	4,202.750	0.01180
2005	25.333	9.523	15.810	13.267	9.523	3.744	12.066	0.483	4,286.805	0.01127
2006	25.170	9.789	15.381	13.472	9.789	3.683	11.698	0.468	4,372.541	0.01070
2007	24.321	11.249	13.072	12.927	11.249	1.678	11.394	0.456	4,459.992	0.01022
2008	24.889	10.700	14.189	13.862	10.700	3.162	11.027	0.441	4,549.192	0.00969
2009	24.779	10.709	14.070	14.103	10.709	3.394	10.676	0.427	4,640.176	0.00920
2010	23.871	12.355	11.516	13.514	12.355	1.159	10.357	0.414	4,732.980	0.00875
2011	24.569	11.554	13.015	14.559	11.554	3.005	10.010	0.400	4,827.640	0.00829
2012	24.473	11.705	12.768	14.840	11.705	3.135	9.633	0.385	4,924.193	0.00782
2013	23.551	13.184	10.367	14.204	13.184	1.020	9.347	0.374	5,022.677	0.00745
2014	24.355	12.242	12.113	15.381	12.242	3.139	8.974	0.359	5,123.131	0.00701
2015	24.331	12.564	11.767	15.715	12.564	3.151	8.616	0.345	5,225.594	0.00660
2016	23.343	14.310	9.033	15.027	14.310	0.717	8.316	0.333	5,330.106	0.00625
2017	24.310	13.316	10.994	16.347	13.316	3.031	7.963	0.319	5,436.708	0.00587
2018	24.315	13.589	10.726	16.739	13.589	3.150	7.576	0.303	5,545.442	0.00546
2019	23.302	15.336	7.966	15.987	15.336	0.651	7.315	0.293	5,656.351	0.00518
2020	24.414	14.094	10.320	17.489	14.094	3.395	6.925	0.277	5,769.478	0.00480
2021	24.524	14.329	10.195	17.974	14.329	3.645	6.550	0.262	5,884.868	0.00445
2022	23.461	16.126	7.335	17.165	16.126	1.039	6.296	0.252	6,002.565	0.00420
2023	24.818	14.834	9.984	18.916	14.834	4.082	5.902	0.236	6,122.616	0.00385
2024	25.055	15.100	9.955	19.585	15.100	4.485	5.470	0.219	6,245.068	0.00351
2025	23.479	16.998	6.481	18.376	16.998	1.378	5.103	0.204	6,369.969	0.00320
2026	24.106	15.639	8.467	19.474	15.639	3.835	4.632	0.185	6,497.368	0.00285

Column Notes:

Col. B: See DTE 98-78, Schedule 1, Page 11, Column (2).
Col. C: See DTE 98-78, Schedule 1, Page 12, Column (2) times NERA Base Load Market Forecast.
Col. D: Col. B - Col. C.
See DTE 99-89 for revised amounts for Cols. E through G.
Col. H: Col. D - Col. G.
Col. I: Col. H Multiplied by 4%.
Col. J: 2003 - 2026, see Page 1, Col. B.
Col. K: Col. I/Col. J Multiplied by 100.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Seabrook Buyout
$ in Millions

	Original Forecast						Revised Forecast				
Year	Nuclear Decommissioning Costs	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Transmission in Support of Remote Generation	Total Filed Case	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L
2003	$0.565	$12.950	$8.813	$4.137	$0.186	$4.888	$ -	$4.888	$0.196	4,173.546	0.00470
2004	0.588	12.438	10.091	2.347	0.184	3.119		3.119	0.125	4,202.750	0.00297
2005	0.614	13.267	9.523	3.744	0.182	4.540		4.540	0.182	4,286.805	0.00425
2006	0.639	13.472	9.789	3.683	0.180	4.502		4.502	0.180	4,372.541	0.00412
2007	0.666	12.927	11.249	1.678	0.178	2.522		2.522	0.101	4,459.992	0.00226
2008	0.695	13.862	10.700	3.162	0.175	4.032		4.032	0.161	4,549.192	0.00354
2009	0.723	14.103	10.709	3.394	0.173	4.290		4.290	0.172	4,640.176	0.00371
2010	0.754	13.514	12.355	1.159	0.171	2.084		2.084	0.083	4,732.980	0.00175
2011	0.785	14.559	11.554	3.005	0.169	3.959		3.959	0.158	4,827.640	0.00327
2012	0.819	14.840	11.705	3.135	0.167	4.121		4.121	0.165	4,924.193	0.00335
2013	0.852	14.204	13.184	1.020	0.165	2.037		2.037	0.081	5,022.677	0.00161
2014	0.888	15.381	12.242	3.139	0.163	4.190		4.190	0.168	5,123.131	0.00328
2015	0.924	15.715	12.564	3.151	0.161	4.236		4.236	0.169	5,225.594	0.00323
2016	(0.014)	15.027	14.310	0.717	0.111	0.814		0.814	0.033	5,330.106	0.00062
2017	(0.013)	16.347	13.316	3.031	0.145	3.163		3.163	0.127	5,436.708	0.00234
2018	(0.013)	16.739	13.589	3.150	0.145	3.282		3.282	0.131	5,545.442	0.00236
2019	(0.011)	15.987	15.336	0.651	0.146	0.786		0.786	0.031	5,656.351	0.00055
2020	(0.011)	17.489	14.094	3.395	0.147	3.531		3.531	0.141	5,769.478	0.00244
2021	(0.010)	17.974	14.329	3.645	0.148	3.783		3.783	0.151	5,884.868	0.00257
2022	(0.009)	17.165	16.126	1.039	0.149	1.179		1.179	0.047	6,002.565	0.00078
2023	(0.007)	18.916	14.834	4.082	0.151	4.226		4.226	0.169	6,122.616	0.00276
2024	(0.007)	19.585	15.100	4.485	0.155	4.633		4.633	0.185	6,245.068	0.00296
2025	(0.006)	18.376	16.998	1.378	0.157	1.529		1.529	0.061	6,369.969	0.00096
2026	(0.004)	19.474	15.639	3.835	0.159	3.990		3.990	0.160	6,497.368	0.00246

Column Notes:

Col. B: See DTE 01-79, Exhibit COM-BKR-1, Page 6, Columns B & C.
Col. C: See Page 11, Column E.
Col. D: See Page 11, Column F.
Col. E: Col. C - Col. D.
Col. F: See DTE 99-90, Schedule 1, Page 7, Column (2).
Col. G: Col. B + Col. E + Col. F.
Col. H: Estimated Buyout Amount per DTE 02-34.
Col. I: Col. G - Col. H.
Col. J: Col. I Multiplied by 4%.
Col. K: See Page 1, Col. B.
Col. L: Col. J/Col. K Multiplied by 100.

Commonwealth Electric Company
Power Contract Obligations
Annual Obligations in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
Jan - Mar														
Apr - May														
Jun - Sep														
Oct - Dec														
2004														
Jan - Feb														
Mar														
Apr - Dec														
2005														
2006														
2007														
2008														
2009														
2010														
2011														
2012														
2013														
2014														
2015														
2016														
2017														
2018														
2019														
2020														
2021														
2022														
2023														

REDACTED

Note: Updated from COM-JFL-3 (supp) in D.T.E. 03-118 with latest forecast from CEA adjusted for buyout of Altresco/Pittsfield.
Differences from NSTAR-COM-GOL-3 indicated by shading.

Commonwealth Electric Company
Power Contract Obligations
Annual Market in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. N	Col. O
Jan - Mar															
Apr - May															
Jun - Sep															
Oct - Dec															
2004															
Jan - Feb															
Mar															
Apr - Dec															
2005															
2006															
2007															
2008															
2009															
2010															
2011															
2012															
2013															
2014															
2015															
2016															
2017															
2018															
2019															
2020															
2021															
2022															
2023															

REDACTED

Note: Cols B thru N are updated from CAM-JFL-3 (supp) in D.T.E. 03-118 with latest forecast from CEA, adjusted for Altresco/Pittsfield buyout
Col.O = Col.P minus Cols. B thru N for Jan 2004 through Feb 2005
Col.P for Jan 2004 through Feb 2005 (Standard Offer period) is equal to the transfer price from NSTAR-GOL-6 & 8 (page 1, line 7)
Col.P for March 2005 onwards = sum Col. B thru Col. N
Differences from NSTAR-COM-GOL-3 indicated by shading

Commonwealth Electric Company
Power Contract Obligations
Annual Above Market in Millions of Dollars

Year	Dartmouth Power	Altresco-Pittsfield	NEA-Bellingham (25MW)	NEA-Bellingham (21MW)	Mass-Power 1	Mass-Power 2	Chicopee Hydro	Collins Hydro	Boott Hydro	Pioneer Hydro	Pilgrim	SEMASS	SEMASS Expansion	S. O. Adjustment	Total
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. N	Col. O
Jan - Mar															
Apr - May															
Jun - Sep															
Oct - Dec															
2004															
Jan - Feb															
Mar															
Apr - Dec															
2005															
2006															
2007															
2008															
2009															
2010															
2011															
2012															
2013															
2014															
2015															
2016															
2017															
2018															
2019															
2020															
2021															
2022															
2023															

REDACTED

Note: Annual above Market = Annual Obligation (p.13) minus Annual Market (p.14)
Differences from NSTAR-COM-GOL-3 indicated by shading.

Commonwealth Electric Company
Transition Charge Mitigation Incentive Mechanism - Altresco-Pittsfield Buyout
$ in Millions

	Original Forecast			Revised Forecast				
Year	Power Contract Total Obligation	Assumed Market Value	Assumed Excess Over Market	Future Power Contract Buyouts	Total Mitigation	Transition Charge Mitigation Incentive @ 4%	Estimated GWH Sales	Impact on Transition Charge (cents/kwh)
Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								

REDACTED

Column Notes:

Col. B: See Exhibit NSTAR-COM-GOL-3, Page 13, Col. C.
Col. C: See Exhibit NSTAR-COM-GOL-3, Page 14, Col. C.
Col. D: Col. B - Col. C.
Col. E: See Page 15, Col. C.
Col. F: Col. D - Col. E.
Col. G: Col. F Multiplied by 4%.
Col. H: 2003- 2011, see Page 1, Col. B.
Col. I: Col. G/Col. H Multiplied by 100.

Commonwealth Electric Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-03	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues [page 5, line 6]		$ (14.159)	$ (13.777)	$ (11.769)	$ (10.990)	$ (10.644)	$ (11.720)	$ (13.757)	$ (14.744)	$ (13.092)	$ (11.381)	$ (11.233)	$ (11.640)	$ (148.906)	$ (39.705)	$ (21.634)	$ (53.313)	$ (34.254)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		14.140	13.777	11.769	10.990	10.644	11.720	13.757	14.744	13.092	11.381	11.233	11.640	148.887	39.686	21.634	53.313	34.254
3	Standard Offer Deferral (Over) / Under Recovery		(0.019)	-	-	-	-	-	-	-	-	-	-	-	(0.019)	(0.019)	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ 0.019**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**					
6	Standard Offer Expense Detail																		
7	NUG Purchases [line 9 minus line 8]		$ 11.241	$ 13.419	$ 9.658	$ 10.558	$ 9.428	$ 9.696	$ 10.460	$ 11.951	$ 11.772	$ 10.262	$ 10.262	$ 9.556	$ 128.263	$ 34.318	$ 19.986	$ 43.879	$ 30.080
8	Short Term Market Transactions [page 4, line 5]		2.899	0.358	2.111	0.432	1.216	2.024	3.297	2.793	1.320	1.119	0.971	2.084	20.624	5.368	1.648	9.434	4.174
9	Standard Offer Expense [line 2]		$ 14.140	$ 13.777	$ 11.769	$ 10.990	$ 10.644	$ 11.720	$ 13.757	$ 14.744	$ 13.092	$ 11.381	$ 11.233	$ 11.640	$ 148.887	$ 39.686	$ 21.634	$ 53.313	$ 34.254
	Annual Interest Rate		1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%					

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period

Jan - Mar	$ 34.318
Apr - May	$ 19.986
Jun - Sep	$ 43.879
Oct - Dec	$ 30.080

Commonwealth Electric Company
Monthly NUG Generation
GWH

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Pilgrim 1																	
2	Pioneer Hydro																	
3	Chicopee Hydro																	
4	Collins Hydro																	
5	Boott Mills Hydro																	
6	SEMASS 1																	
7	SEMASS 2																	
8	Northeast Energy (21 MW)																	
9	Northeast Energy (25 MW)																	
10	Dartmouth Power																	
11	MASSPOWER 1																	
12	MASSPOWER 2																	
13	Altresco-Pittsfield Replacement Power																	
14	Altresco-Pittsfield																	
15	NUGs Generation																	
16	Less: Assumed Line Losses @																	
17	Net GWH Delivered																	
18	Dist Co Settlement Price (line 19 / line 17)																	
19	Cost of NUG Purchases (page 1, line 7)																	

REDACTED

Commonwealth Electric Company
Total NUG Cost
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Pilgrim 1																	
2	Pioneer Hydro																	
3	Chicopee Hydro																	
4	Collins Hydro																	
5	Boott Mills Hydro																	
6	SEMASS 1																	
7	SEMASS 2																	
8	Northeast Energy (21 MW)																	
9	Northeast Energy (25 MW)																	
10	Dartmouth Power																	
11	MASSPOWER 1																	
12	MASSPOWER 2																	
13	Altresco - Pittsfield																	
14	Total NUG Cost																	

REDACTED

Commonwealth Electric Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Account	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
	Cost																		
1	Short Term SO - Sales		$ (10.661)	$ (10.469)	$ (8.090)	$ (8.476)	$ (6.882)	$ (7.486)	$ (9.150)	$ (9.111)	$ (7.393)	$ (7.456)	$ (7.514)	$ (7.851)	$ (100.539)	$ (29.220)	$ (15.358)	$ (33.140)	$ (22.821)
2	Mirant		5.820	4.193	4.453	4.248	3.801	4.312	5.027	4.812	3.963	3.955	3.835	4.378	52.797	14.466	8.049	18.114	12.168
3	Short Term SO		7.740	6.634	5.748	4.660	4.297	5.198	7.420	7.092	4.750	4.620	4.650	5.557	68.366	20.122	8.957	24.460	14.827
4	Altresco-Pittsfield Replacement Power		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Total ST Market Transaction Cost		$ 2.899	$ 0.358	$ 2.111	$ 0.432	$ 1.216	$ 2.024	$ 3.297	$ 2.793	$ 1.320	$ 1.119	$ 0.971	$ 2.084	$ 20.624	$ 5.368	$ 1.648	$ 9.434	$ 4.174
6	GWH																		
7	Short Term SO - Sales (page 2, line 15)		(202.595)	(208.315)	(179.422)	(202.868)	(174.855)	(186.212)	(192.419)	(192.419)	(186.212)	(192.419)	(186.212)	(192.419)	(2,296.367)				
8																			
9	ST Sales Price/MWH							40.20	47.55	47.35	39.70	38.75	40.35	40.80					

Note
Short term SO sales on line 1 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Commonwealth Electric Company
Standard Offer Revenue
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues																	
2	Residential	$ 8.339	$ 7.914	$ 6.660	$ 6.073	$ 5.536	$ 5.461	$ 6.944	$ 7.656	$ 6.428	$ 5.259	$ 5.230	$ 5.679	$ 77.179	$ 22.913	$ 11.609	$ 26.489	$ 16.168
3	Commercial	5.347	5.336	4.641	4.399	4.588	5.128	5.695	5.979	5.561	5.024	4.914	4.879	61.491	15.324	8.987	22.363	14.817
4	Industrial	0.409	0.472	0.415	0.472	0.479	1.092	1.081	1.069	1.058	1.048	1.037	1.026	9.658	1.296	0.951	4.300	3.111
5	Street Lighting	0.064	0.055	0.053	0.046	0.041	0.039	0.037	0.040	0.045	0.050	0.052	0.056	0.578	0.172	0.087	0.161	0.158
6	Total Standard Offer Revenues	$ 14.159	$ 13.777	$ 11.769	$ 10.990	$ 10.644	$ 11.720	$ 13.757	$ 14.744	$ 13.092	$ 11.381	$ 11.233	$ 11.640	$ 148.906	$ 39.705	$ 21.634	$ 53.313	$ 34.254
7	Standard Offer Price						$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100					
8	SOSFA Price						$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223					
9	GWH Sales																	
10	Standard Offer GWH Sales	227.747	218.264	186.408	174.022	168.640	185.346	217.559	233.191	207.070	179.998	177.644	184.089	2,359.978	632.419	342.662	843.166	541.731

Commonwealth Electric Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-03	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues [page 5, line 6]		$ (14.159)	$ (13.777)	$ (11.769)	$ (10.990)	$ (10.644)	$ (11.720)	$ (13.757)	$ (14.744)	$ (13.092)	$ (11.381)	$ (11.233)	$ (11.640)	$ (148.906)	$ (39.705)	$ (21.634)	$ (53.313)	$ (34.254)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		14.140	13.777	11.769	10.990	10.644	11.720	13.757	14.744	13.092	11.381	11.233	11.640	148.887	39.686	21.634	53.313	34.254
3	Standard Offer Deferral (Over) / Under Recovery		(0.019)	-	-	-	-	-	-	-	-	-	-	-	(0.019)	(0.019)	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ 0.019**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**					
6	Standard Offer Expense Detail																		
7	NUG Purchases [line 9 minus line 8]		$ 11.241	$ 13.419	$ 9.658	$ 10.558	$ 9.428	$ 9.696	$ 10.460	$ 11.951	$ 11.772	$ 9.751	$ 9.779	$ 9.062	$ 126.775	$ 34.318	$ 19.986	$ 43.879	$ 28.592
8	Short Term Market Transactions [page 4, line 5]		2.899	0.358	2.111	0.432	1.216	2.024	3.297	2.793	1.320	1.630	1.454	2.578	22.112	5.368	1.648	9.434	5.662
9	Standard Offer Expense [line 2]		$ 14.140	$ 13.777	$ 11.769	$ 10.990	$ 10.644	$ 11.720	$ 13.757	$ 14.744	$ 13.092	$ 11.381	$ 11.233	$ 11.640	$ 148.887	$ 39.686	$ 21.634	$ 53.313	$ 34.254
	Annual Interest Rate		1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%	1.65%					

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period

Jan - Mar	$ 34.318
Apr - May	$ 19.986
Jun - Sep	$ 43.879
Oct - Dec	$ 28.592

Commonwealth Electric Company
Monthly NUG Generation
GWH

Line	Description		Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Pilgrim 1																		
2	Pioneer Hydro																		
3	Chicopee Hydro																		
4	Collins Hydro																		
5	Boott Mills Hydro																		
6	SEMASS 1																		
7	SEMASS 2																		
8	Northeast Energy (21 MW)																		
9	Northeast Energy (25 MW)																		
10	Dartmouth Power																		
11	MASSPOWER 1																		
12	MASSPOWER 2																		
13	Altresco-Pittsfield Replacement Power																		
14	Altresco-Pittsfield																		
15	NUGs Generation																		
16	Less: Assumed Line Losses @	6.36%																	
17	Net GWH Delivered																		
18	Dist Co Settlement Price (line 19 / line 17)																		
19	Cost of NUG Purchases (page 1, line 7)																		

REDACTED

Commonwealth Electric Company
Total NUG Cost
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Pilgrim 1																	
2	Pioneer Hydro																	
3	Chicopee Hydro																	
4	Collins Hydro																	
5	Boott Mills Hydro																	
6	SEMASS 1																	
7	SEMASS 2																	
8	Northeast Energy (21 MW)																	
9	Northeast Energy (25 MW)																	
10	Dartmouth Power																	
11	MASSPOWER 1																	
12	MASSPOWER 2																	
13	Altresco - Pittsfield																	
14	Total NUG Cost																	

REDACTED

Commonwealth Electric Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
	Cost																	
1	Short Term SO - Sales	$ (10.661)	$ (10.469)	$ (8.090)	$ (8.476)	$ (6.882)	$ (7.486)	$ (9.150)	$ (9.111)	$ (7.393)	$ (7.757)	$ (7.817)	$ (8.168)	$ (101.460)	$ (29.220)	$ (15.358)	$ (33.140)	$ (23.742)
2	Mirant	5.820	4.193	4.453	4.248	3.801	4.312	5.027	4.812	3.963	3.955	3.835	4.378	52.797	14.466	8.049	18.114	12.168
3	Short Term SO	7.740	6.634	5.748	4.660	4.297	5.198	7.420	7.092	4.750	4.620	4.650	5.557	68.366	20.122	8.957	24.460	14.827
4	Altresco-Pittsfield Replacement Power	-	-	-	-	-	-	-	-	-	0.812	0.786	0.811	2.409	-	-	-	2.409
5	Total ST Market Transaction Cost	$ 2.899	$ 0.358	$ 2.111	$ 0.432	$ 1.216	$ 2.024	$ 3.297	$ 2.793	$ 1.320	$ 1.630	$ 1.454	$ 2.578	$ 22.112	$ 5.368	$ 1.648	$ 9.434	$ 5.662
6	GWH																	
7	Short Term SO - Sales (page 2, line 15)	(202.595)	(208.315)	(179.422)	(202.868)	(174.855)	(186.212)	(192.419)	(192.419)	(186.212)	(200.189)	(193.732)	(200.188)	(2,319.426)	(590.332)	(377.723)	(757.262)	(594.109)
8																		
9	ST Sales Price/MWH						40.20	47.55	47.35	39.70	38.75	40.35	40.80					

Note
Short term SO sales on line 1 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Commonwealth Electric Company
Standard Offer Revenue
$ in Millions

Line	Description	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Estimate Jun-04	Estimate Jul-04	Estimate Aug-04	Estimate Sep-04	Estimate Oct-04	Estimate Nov-04	Estimate Dec-04	Total	Subtotal Jan - Mar	Subtotal Apr - May	Subtotal Jun - Sep	Subtotal Oct - Dec
1	Standard Offer Revenues																	
2	Residential	$ 8.339	$ 7.914	$ 6.660	$ 6.073	$ 5.536	$ 5.461	$ 6.944	$ 7.656	$ 6.428	$ 5.259	$ 5.230	$ 5.679	$ 77.179	$ 22.913	$ 11.609	$ 26.489	$ 16.168
3	Commercial	5.347	5.336	4.641	4.399	4.588	5.128	5.695	5.979	5.561	5.024	4.914	4.879	61.491	15.324	8.987	22.363	14.817
4	Industrial	0.409	0.472	0.415	0.472	0.479	1.092	1.081	1.069	1.058	1.048	1.037	1.026	9.658	1.296	0.951	4.300	3.111
5	Street Lighting	0.064	0.055	0.053	0.046	0.041	0.039	0.037	0.040	0.045	0.050	0.052	0.056	0.578	0.172	0.087	0.161	0.158
6	Total Standard Offer Revenues	$ 14.159	$ 13.777	$ 11.769	$ 10.990	$ 10.644	$ 11.720	$ 13.757	$ 14.744	$ 13.092	$ 11.381	$ 11.233	$ 11.640	$ 148.906	$ 39.705	$ 21.634	$ 53.313	$ 34.254
7	Standard Offer Price						$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100	$ 0.05100					
8	SOSFA Price						$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223	$ 0.01223					
9	GWH Sales																	
10	Standard Offer GWH Sales	227.747	218.264	186.408	174.022	168.640	185.346	217.559	233.191	207.070	179.998	177.644	184.089	2,359.978	632.419	342.662	843.166	541.731

Commonwealth Electric Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-04	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues [page 5, line 6]		$ (14.400)	$ (13.801)	$ (28.201)	$ (28.201)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		14.400	13.801	28.201	28.201
3	Standard Offer Deferral (Over) / Under Recovery		-	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ -**	**$ -**	**$ -**		
6	Standard Offer Expense Detail					
7	NUG Purchases [line 9 minus line 8]		$ 9.527	$ 10.737	$ 20.264	$ 20.264
8	Short Term Market Transactions [page 4, line 5]		4.873	3.064	7.937	7.937
9	Standard Offer Expense [line 2]		$ 14.400	$ 13.801	$ 28.201	$ 28.201
	Annual Interest Rate		1.65%	1.65%		

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Jan - Feb $ 20.264

Commonwealth Electric Company
Monthly NUG Generation
GWH

Line	Description		Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Pilgrim 1					
2	Pioneer Hydro					
3	Chicopee Hydro					
4	Collins Hydro					
5	Boott Mills Hydro					
6	SEMASS 1					
7	SEMASS 2					
8	Northeast Energy (21 MW)					
9	Northeast Energy (25 MW)					
10	Dartmouth Power					
11	MASSPOWER 1					
12	MASSPOWER 2					
13	Altresco-Pittsfield Replacement Power					
14	Altresco-Pittsfield					
15	NUGs Generation					
16	Less: Assumed Line Losses @	6.36%				
17	Net GWH Delivered					
18	Dist Co Settlement Price (line 19 / line 17)					
19	Cost of NUG Purchases (page 1, line 7)					

REDACTED

Commonwealth Electric Company
Total NUG Cost
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Pilgrim 1				
2	Pioneer Hydro				
3	Chicopee Hydro				
4	Collins Hydro				
5	Boott Mills Hydro				
6	SEMASS 1				
7	SEMASS 2				
8	Northeast Energy (21 MW)				
9	Northeast Energy (25 MW)				
10	Dartmouth Power				
11	MASSPOWER 1				
12	MASSPOWER 2				
13	Altresco - Pittsfield				
14	Total NUG Cost				

REDACTED

Commonwealth Electric Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
	Cost				
1	Short Term SO - Sales	$ (8.687)	$ (7.763)	$ (16.450)	$ (16.450)
2	Mirant	5.820	4.193	10.013	10.013
3	Short Term SO	7.740	6.634	14.374	14.374
4	Altresco-Pittsfield Replacement Power	-	-	-	-
5	Total ST Market Transaction Cost	$ 4.873	$ 3.064	$ 7.937	$ 7.937
6	GWH				
7	Short Term SO - Sales (page 2, line 15)	(166.574)	(150.454)	(317.028)	
8					
9	ST Sales Price/MWH	52.15	51.60		

Note
Short term SO sales on line 1 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Commonwealth Electric Company
Standard Offer Revenue
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues				
2	Residential	$ 8.472	$ 7.916	$ 16.388	$ 16.388
3	Commercial	5.447	5.353	10.800	10.800
4	Industrial	0.417	0.477	0.894	0.894
5	Street Lighting	0.064	0.055	0.119	0.119
6	Total Standard Offer Revenues	$ 14.400	$ 13.801	$ 28.201	$ 28.201
7	Standard Offer Price	$ 0.05100	$ 0.05100		
8	SOSFA Price	$ 0.01223	$ 0.01223		
9	GWH Sales				
10	Standard Offer GWH Sales	227.747	218.264	446.011	446.011

Commonwealth Electric Company
Monthly Standard Offer Deferral
$ in Millions

Line	Description	Dec-04	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Standard Offer Revenues [page 5, line 6]		$ (14.400)	$ (13.801)	$ (28.201)	$ (28.201)
2	Standard Offer Expense (minus line 1 minus prior mo. line 5)		14.400	13.801	28.201	28.201
3	Standard Offer Deferral (Over) / Under Recovery		-	-	-	-
4	Interest on SO Deferral Balance [Note]		-	-	-	-
5	SO Deferral (Over) / Under Ending Balance	**$ -**	**$ -**	**$ -**		**$ -**
6	Standard Offer Expense Detail					
7	NUG Purchases [line 9 minus line 8]		$ 9.133	$ 10.386	$ 19.519	$ 19.519
8	Short Term Market Transactions [page 4, line 5]		5.267	3.415	8.682	8.682
9	Standard Offer Expense [line 2]		$ 14.400	$ 13.801	$ 28.201	$ 28.201
	Annual Interest Rate		1.65%	1.65%		

Note:
The transfer prices of the value of the NUGs is taken from line 7 and appears in GOL-3 page 14 in column E in the appropriate time period.

Jan - Feb $ 19.519

Commonwealth Electric Company
Monthly NUG Generation
GWH

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Pilgrim 1	-	-	-	-
2	Pioneer Hydro				
3	Chicopee Hydro				
4	Collins Hydro				
5	Boott Mills Hydro				
6	SEMASS 1				
7	SEMASS 2				
8	Northeast Energy (21 MW)				
9	Northeast Energy (25 MW)				
10	Dartmouth Power				
11	MASSPOWER 1				
12	MASSPOWER 2				
13	Altresco-Pittsfield Replacement Power				
14	Altresco-Pittsfield				
15	NUGs Generation				
16	Less: Assumed Line Losses @				
17	Net GWH Delivered				
18	Dist Co Settlement Price (line 19 / line 17)				
19	Cost of NUG Purchases (page 1, line 7)				

REDACTED

Commonwealth Electric Company
Total NUG Cost
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Feb
1	Pilgrim 1	$ -	$ -	$ -	$ -
2	Pioneer Hydro				
3	Chicopee Hydro				
4	Collins Hydro				
5	Boott Mills Hydro				
6	SEMASS 1				
7	SEMASS 2				
8	Northeast Energy (21 MW)				
9	Northeast Energy (25 MW)				
10	Dartmouth Power				
11	MASSPOWER 1				
12	MASSPOWER 2				
13	Altresco - Pittsfield				
14	Total NUG Cost				

REDACTED

Commonwealth Electric Company
Monthly Short Term Market Transactions
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Mar
	Cost				
1	Short Term SO - Sales	$ (8.293)	$ (7.412)	$ (15.705)	$ (15.705)
2	Mirant	5.820	4.193	10.013	10.013
3	Short Term SO	7.740	6.634	14.374	14.374
4	Altresco-Pittsfield Replacement Power	-	-	-	-
5	Total ST Market Transaction Cost	$ 5.267	$ 3.415	$ 8.682	$ 8.682
6	GWH				
7	Short Term SO - Sales (page 2, line 15)	(159.031)	(143.641)	(302.672)	(302.672)
8					
9	ST Sales Price/MWH	52.15	51.60		

Note
Short term SO sales on line 1 are calculated using the Short Term SO GWH on line 7 by the selling price on line 9.

Commonwealth Electric Company
Standard Offer Revenue
$ in Millions

Line	Description	Estimate Jan-05	Estimate Feb-05	Total	Subtotal Jan - Mar
1	Standard Offer Revenues				
2	Residential	$ 8.472	$ 7.916	$ 16.388	$ 16.388
3	Commercial	5.447	5.353	10.800	10.800
4	Industrial	0.417	0.477	0.894	0.894
5	Street Lighting	0.064	0.055	0.119	0.119
6	Total Standard Offer Revenues	$ 14.400	$ 13.801	$ 28.201	$ 28.201
7	Standard Offer Price	$ 0.05100	$ 0.05100		
8	SOSFA Price	$ 0.01223	$ 0.01223		
9	GWH Sales				
10	Standard Offer GWH Sales	227.747	218.264	446.011	446.011

CAMBRIDGE ELECTRIC LIGHT COMPANY
COMMONWEALTH ELECTRIC COMPANY
d/b/a NSTAR ELECTRIC

Direct Testimony of Robert B. Hevert on Pittsfield Terminations

Exhibit NSTAR-RBH

D.T.E. 04-60

I. INTRODUCTION

Q. Please state your name, affiliation and business address.

A. My name is Robert B. Hevert and I am President of Concentric Energy Advisors, Inc. ("CEA"), located at 313 Boston Post Road West, Suite 210, Marlborough, Massachusetts 01752.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Cambridge Electric Light Company ("Cambridge") and Commonwealth Electric Company ("Commonwealth") (together with Boston Edison Company ("Boston Edison"), "NSTAR Electric" or the "Company").

Q. Please describe the nature of the services provided by CEA.

A. CEA is a management consulting and economic advisory firm focused on the North American energy and water industries. CEA specializes in transaction-related financial advisory services including merger, acquisition and divestiture engagements, as well as strategic and management consulting services. Prior to CEA, the majority of CEA's staff were members of Reed Consulting Group ("RCG"), which subsequently was acquired by Navigant Consulting, Inc. ("NCI").

Since 1997, CEA staff members have advised either the seller or a prospective buyer of physical or contractual generation assets in numerous transactions. On the sell side, CEA's staff has provided advisory services in transactions with an aggregate value

in excess of $20 billion**.** Specific sell-side engagements for power purchase agreements ("PPAs") on which CEA staff members have worked include the NSTAR Electric 1999 auction process for its PPA Entitlements, Standard Offer and Default Service supply, as well as Niagara Mohawk Power Corporation's 2000 auction for approximately 6,000 megawatts ("MW") of contracted capacity.

More recently, CEA served as sell-side advisor to Rochester Gas and Electric in its R.E. Ginna nuclear power plant sale, which included a long-term PPA for energy and capacity associated with the plant. Other transactions including physical and contractual assets for which CEA staff members had been retained include: Boston Edison's fossil fuel-fired generation assets; Boston Edison's Pilgrim nuclear station; Eastern Utilities Associates fossil and hydro generating assets; Central Hudson Gas and Electric; GPU fossil, hydro, development properties and GENCo divestiture; GPU Oyster Creek nuclear station; Potomac Electric Power Company generation assets and power contracts; Nine Mile Point Units 1 and 2; and Conectiv's fossil and nuclear generating assets. On the buy-side, CEA staff members have represented or otherwise supported numerous confidential clients in the assessment and valuation of various merchant and utility generating resources.

Q. What services have CEA staff members provided on the sell-side of generation divestiture transactions specifically regarding PPAs?

A. On the sell side of power contracts and entitlements, CEA staff members have been involved in all aspects of the auction process, from process design to transaction closing.

Those responsibilities have included: developing the overall sales process; enhancing market interest in the assets being sold through the development of detailed offering materials; assisting the seller in establishing the transaction terms; managing the due diligence process; reviewing transaction documents; reviewing and analyzing round bids; assisting in negotiations with bidders; providing financial valuations of the assets; and assisting in obtaining required regulatory and corporate approvals, including the preparation and delivery of fairness opinions. In that regard, CEA staff members have provided testimony in several jurisdictions regarding auction processes and the fair value of assets.

Q. Do CEA staff members have experience in evaluating contractual resources other than in divestiture-related auctions?

A. Yes. In addition to the divestiture experience described above, CEA staff members have worked with various confidential clients to develop or assess resource portfolio optimization and generation strategies. Those clients include regulated utilities, non-regulated generation companies, and municipal utilities. In many instances, these clients required valuations of their generation resources, both physical and contractual, for the purposes of financing, strategy development, resource planning, or transaction planning.

Q. Please describe your professional experience.

A. I have served as an executive and manager with other consulting firms (RCG and NCI), and as an officer of Bay State Gas Company. I have provided testimony regarding strategic and financial matters before state several utility regulatory agencies, and have

advised numerous clients on all aspects of generation asset acquisition and divestiture transactions on both the buy and sell-side. Among other transactions, my sell-side advisory experience includes the fall 1999 initial auction of the NSTAR Electric power contracts. A summary of my professional and educational background is attached as Exhibit NSTAR-RBH-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the Company's auction process for the sale or transfer of its rights to 24 Power Purchase Agreements (the "PPA Entitlements" or the "Contracts"), and to support the Company's testimony as to the results of that process. In particular, my testimony will address the results of the auction process for the Pittsfield PPA Entitlements (collectively referred to herein as the "Pittsfield Contracts").

Q. Please summarize your testimony.

A. Following this introduction, I describe the circumstances leading up to the Company's divestiture, discuss the auction's overall design and implementation, and provide an overview of the results of the auction process. My testimony will also address the auction structure relative to the standards established by the Department of Telecommunications and Energy (the "Department") in accordance with the Electric Restructuring Act (the "Act").

II. DESCRIPTION OF AUCTION PROCESS

Q. Why did the Company choose to auction the PPA Entitlements at this time?

A. The Company chose to auction its PPA Entitlements for a number of reasons. In accordance with the terms of the Department-approved Restructuring Settlement (for Boston Edison) and the Department-approved Restructuring Plan (for Cambridge and Commonwealth), NSTAR Electric was obligated to divest its fossil, nuclear and contractual generation resources. Although it completed the divestiture of its fossil and nuclear generation resources, the Company has not been able to complete the transfer of all of its contractual resources. Indeed, during 1999 and into 2000, the Company conducted auctions of its portfolio of power contracts, but did not enter into any definitive agreements as a result of that process. In 2003, the Company decided to re-auction its PPA Entitlements with the intent of transferring or otherwise divesting the contracts if the resulting transactions were likely to mitigate the above-market costs associated with those contracts.

Q. How did the Company develop its PPA Entitlement divestiture program?

A. The Company began developing the current PPA Entitlement divestiture program in July, 2003 when it established a team of employees whose objective it was to develop and implement a process designed to mitigate, to the greatest possible extent, the above-market costs associated with the Contracts. The divestiture team, which had responsibility for four major areas: (1) Developing the Offering Memorandum and Early Interest Package; (2) Marketing, communications, and bidder support; (3) Conducting the

Auction; and (4) Bid Evaluation and Recommendations, included Company employees and consultants from CEA. Throughout the process, the divestiture team met weekly (in face-to-face meetings or via conference call) to ensure that all aspects of the process were integrated and coordinated, and to maintain communication among all parties. In addition, the divestiture team periodically met with Company management to report progress and to make decisions critical to the auction process.

Q. The auction process has taken nearly one year from the initial planning stage to the signing of transaction agreements. Please explain why that schedule is reasonable.

A. I believe this schedule is reasonable for several reasons. First, the auction of a portfolio of power contracts is an extremely complex transaction due to the myriad legal, tax, accounting, marketing, regulatory and valuation issues, each of which must be thoroughly developed and vetted at the outset of the process. In addition, as explained later in my testimony, the Company encouraged bidders to submit bids on any combination of contracts in order to maximize the value of the portfolio. While the advantage of that bidding structure was to heighten the competitive pressure among bidders, it also complicated and lengthened the amount of time needed to adequately review and negotiate competing bids.

Q. Please describe the Company's objectives for the PPA Entitlement divestiture process.

A. The Company and CEA sought to design an auction that was equitable and structured to maximize the mitigation of transition costs associated with the Contracts. As such, our

objective was to implement a process that ensured complete, uninhibited, non-discriminatory access to all data and information by any and all interested parties seeking to participate. Accordingly, the primary objectives of the divestiture process included:

- Minimizing the above-market costs associated with the PPA Entitlements;
- Developing, implementing and maintaining the most competitive auction process possible;
- Ensuring fair treatment of all bidders;
- Ensuring that the auction process was timely, efficient, and unbiased.

Q. Please describe the specific responsibilities of the divestiture team.

A. As noted earlier, the divestiture team had responsibility for four major areas: (1) Developing the Offering Memorandum and Early Interest Package; (2) Marketing, communications, and bidder support; (3) Conducting the Auction; and (4) Bid Evaluation and Recommendations.

Q. What were the team's responsibilities regarding communications?

A. The team's overall communications objective was to manage internal and external communications regarding the auction process. More specifically, the team was responsible for managing communications with Company management, developing press releases and responding to media calls.

Q. What were the team's responsibilities with respect to marketing, due diligence, and bidder support?

A. These responsibilities included all activities associated with marketing the PPA Entitlements. Such activities included identifying the target market, developing and delivering marketing materials, and soliciting expressions of interest through direct mail, and telephonic contact. These activities also included drafting the Early Interest Package and Offering Memorandum, negotiating and executing Confidentiality Agreements, evaluating bidder qualifications, preparing bid instructions, and analyzing all bids. Throughout the auction process, the team also focused on treating all bidders consistently and fairly.

The team was also responsible for managing the due diligence process, including the preparation of documentation CD-ROMs, managing bidder questions and answers ("Q&As"), and participating in or facilitating meetings or conference calls between individual bidders and company personnel. The due diligence process, which is discussed in more detail later in my testimony, was designed to ensure that each bidder received the information necessary to satisfactorily complete its evaluation of the PPA Entitlements, and that such information was provided in a consistent, timely, and equitable manner.

As discussed later in my testimony, CEA staff members supported bidders throughout the due diligence process by serving as "bidder representatives". That is, each bidder was assigned a specific CEA staff member to whom all questions and

scheduling issues were directed. The bidder representatives worked with their respective bidders to resolve any unanswered questions and to schedule meetings or conference calls with Company personnel.

Q. Please describe the team's responsibilities as they relate to terms of sale.

A. The divestiture team was responsible for developing the principal terms of the transaction documents. In that role, the divestiture team worked closely with the Company to develop the key transaction parameters. The team's primary objectives for the transaction terms were to maximize the mitigation of transition costs associated with the PPA Entitlements.

Q. What are the divestiture team's responsibilities with respect to the closing process?

A. The divestiture team is responsible for all activities after the execution of transaction documents through final closing. CEA provided analysis, recommendations and support through the negotiations, which NSTAR conducted. The team will continue to support the legal advisors and will seek the expeditious approval of the transaction.

Q. Please provide an overview of the auction process used to market the PPA Entitlements.

A. The auction process was developed with the primary objective of mitigating, to the greatest extent possible, the above-market costs associated with the PPA Entitlements. Accordingly, the process was designed to be a fair, unbiased process in which bidders would have the ability and opportunity to maximize the value of their respective bids. Initially, CEA undertook an aggressive preliminary marketing campaign during which

interest in the PPA Entitlements was developed and solicited from numerous potential bidders. Throughout the auction process, substantial amounts of information and documentation relating to the PPA Entitlements, together with ongoing due diligence support, were provided to all qualified bidders. At the end of the bid process, bidders submitted their bids, including both pricing and contractual terms ("Bids"). A time line and overview of the auction process is provided in Exhibit NSTAR-RBH-2.

Q. How did the Company initially market the PPA Entitlements?

A. The initial marketing phase began on October 1, 2003 when NSTAR Electric publicly announced its intention to sell or transfer the 24 PPA Entitlements. Following that announcement, an Early Interest Package was sent to approximately 90 potential bidders including the counterparties to the PPAs, global, national and regional energy companies, unregulated affiliates of electric and gas utility companies, project developers, energy marketers, financial advisors and investment firms.

Q. Please describe the Early Interest Package.

A. The Early Interest Package included an Early Interest Letter ("EIL"), a Confidentiality Agreement, and a Request for Qualifications ("RFQ"). Copies of all documents are included as NSTAR-RBH-3. The EIL provided a brief description of the PPA Entitlements, a general overview of the regional market, and contact instructions for interested parties seeking additional information regarding the Contracts or wishing to participate in the bidding process. The EIL also encouraged interested parties to consider bidding on any or all of the PPA Entitlements. The broad distribution of the EIL Package

and the direct marketing efforts undertaken by CEA were intended to maximize the likelihood of participation by the largest and most competitive group of qualified bidders.

Q. Were prospective bidders required to execute any documents to be admitted into the auction process?

A. Yes. Bidders were required to execute a Confidentiality Agreement as a condition of receiving any further information regarding the PPA Entitlements. As discussed below, bidders were also required to submit a completed Qualifications Package in order to be considered "Qualified Bidders."

Q. How many responses did the Company receive in response to the Early Interest Package?

A. Over the period beginning October 1, 2003 and ending November 15, 2003, CEA and the Company received responses from and negotiated Confidentiality Agreements with 25 interested parties. The Company subsequently received complete qualifications packages from the 25 parties that signed Confidentiality Agreements.

Q. Why was the Confidentiality Agreement important to the auction process?

A. For any competitive bidding process to be effective, all parties must be confident that the process is fair to all participants and that it will produce a conclusive result. To that end, all bidders must have equal access to relevant information regarding the subject assets. The Confidentiality Agreement provided a means by which the Company was able to provide such information to bidders without otherwise adversely affecting either the Company or the prospective counterparties. Among other provisions, the Confidentiality

Agreement provided that bidders were precluded from disclosing the information obtained in the auction process to any other party, and from using the information for any purpose other than evaluating the PPA Entitlements. As noted above, the execution of the Confidentiality Agreement was a prerequisite for participation in the auction process.

Q. Has the Company disclosed the names of the bidders?

A. No. With the exception of the announcement of the winning bidders for individual contracts, the bidders' names have continued to be, and will continue to be, treated as confidential.

Q. How did the Company evaluate the interested parties' qualifications?

A. The Qualifications Package was designed to provide the Company and CEA specific financial, legal and operating information regarding the bidder or bidding group, as the case may be. The intent of the RFQ and the qualification process was to ensure that all bidders selected for participation in the process had the operating and financial wherewithal required to assume and administer the PPA Entitlements in the event an Entitlement Transfer Agreement was required. The RFQ sought the following information:

- An identification of the bidder, including any advisors, anticipated partners, and any known source of funds;
- An identification of the assets that the bidder owns, operates or controls within NEPOOL for the purpose of assessing potential market power issues;
- A description of the company's financial qualifications;

- A summary of any conflicts of interest between the bidder and NSTAR; and
- A summary of the internal and external approvals necessary to close the transaction.

The Company evaluated the qualifications packages on a rolling basis such that each bidder's qualifications were reviewed at the time they were received.

Q. Is the qualification process important?

A. Yes, it is especially important in the case of a third-party transaction under which an Entitlement Transfer Agreement ("ETA") would be the governing transaction document, and the ETA counterparty would have a series of continuing obligations.[1] As set forth in the ETA, bankruptcy by either party (or its guarantor) represents an event of default, a remedy of which would be the early termination of the agreement. Given the time and resources needed to develop, implement and close a PPA auction process, the Company prudently chose to establish a qualification process to avoid such costs.[2]

Q. Please describe the Due Diligence Stage of the Competitive Bidding Process.

A. The Due Diligence Stage began on October 17, 2003 when the Offering Memorandum ("OM") and the ETA were sent to 22 parties that executed the Confidentiality Agreements. (Three bidders voluntarily withdrew from the process shortly after

---

[1] An ETA establishes a contractual arrangement in which a party that is unaffiliated with the generating facility agrees to accept deliveries of electricity in accordance with the terms of existing PPAs. As discussed later in my testimony, the qualifications process is less critical in the case of a termination agreement with a current Contract counterparty.

[2] This concern is not academic. In D.P.U./D.T.E 97-94, the Department approved the transfer of certain PPAs from New England Power Company to USGen New England, Inc. On July 8, 2003, USGen New England, along with several of its affiliate companies, filed for Chapter 11 bankruptcy protection.

receiving the OM.) The OM included a detailed description of each Contract, an overview of the bidding process, and the preliminary Terms of Sale.

In addition to receiving the OM, Qualified Bidders also received a documentation CD-ROM that included all of the PPA Entitlement agreements and amendments as well as the associated invoices, and an electronic contract evaluation spreadsheet for each of the PPA Entitlements. It is important to note that the evaluation spreadsheet was provided for the convenience of qualified bidders, and that all bidders were encouraged to perform their own independent evaluation of the Contracts.

As noted earlier, each Qualified Bidder was assigned a dedicated CEA Bidder Representative and was encouraged to conduct due diligence by sending written questions to CEA via e-mail. The Bidder Representatives were the single point of contact for their respective bidders regarding all matters relating to the competitive bidding process. As such, the Bidder Representatives both facilitated the due diligence process for their bidders and, by serving as the single point of contact, ensured that confidentiality was maintained throughout the auction process.

Q. How was the Q&A process, including requests for additional documentation handled during the due diligence process?

A. Throughout the due diligence process, bidders were encouraged to send written questions to CEA via a separate e-mail address. CEA received and reviewed the questions and, if necessary, forwarded the questions to the appropriate company personnel. Responses to those questions were provided as quickly as possible. In addition, while bidders

generally received answers to their specific questions, from time to time CEA and the Company determined that the information requested by one bidder should be made available to all bidders. Such information (e.g., scheduling and timing of bids) generally was intended to clarify issues that likely would apply to all bidders regardless of the Contact or Contracts for which they were bidding.

Q. Did bidders receive specific instructions for submitting their bids?

A. Yes, on November 6, 2003 bid instructions were made available to all bidders. A PPA Entitlement Bid Form was also sent to each bidder as an attachment to the bid instructions. The Bid Instructions, which set a due date of Friday November 21, 2003 for the receipt of Bids, specified the form and content in which Bids were to be submitted. A copy of the Bid Instructions, including the Bid Form, is provided as NSTAR-RBH-4. According to those instructions, Bids were to include the following elements:

1. The Bid Form;
2. Confirmation of the Bidding Group and Ownership Structure;
3. Identification of advisors;
4. Identification of interest by identifying the PPA Entitlements for which the bid was submitted;
5. Pricing options for each PPA Entitlement for which the bid was submitted;
6. Identification of any regulatory or other approvals or consents required to close the transactions;

7. Identification of the entity providing credit support and an explanation of how the required financial security would be provided;

8. Any exceptions to the ETA, the document through which the rights and obligations under any non-assignable contracts would be transferred.

Among other things, the Bid Instructions stated that any Bid subject to internal approvals or financing may be rejected, and that the nature and extent of proposed modifications to the ETA would be taken into consideration when evaluating bids. As discussed below, the Bid Instructions were designed to enable the Company and CEA to evaluate all bids on a comparable basis.

Q. How was the bid form structured?

A. The PPA Entitlement Bid Form included two pricing options. Option 1 provided for a lump sum payment from the Bidder to NSTAR Electric or from NSTAR Electric to the Bidder, based on NSTAR Electric paying the indicated monthly support payments for each contract. Bid Option 2 was for PPA Entitlements with energy only pricing (no fixed charges). Under Option 2 Qualified Bidders were asked to indicate the price per megawatt hour they would pay to NSTAR Electric for energy delivered under the specific PPA Entitlement. The Bid Form also required that each bid cover the remaining term and for the full output associated with any PPA Entitlement. The Bid Form also required Qualified Bidders to specify in their bid package whether each bid was separable from other PPA Entitlement bids. In addition, the Bid Form also noted that any re-

marking mechanisms required by bidders due to the passage of time were to be based on publicly available indices or data sources.

III. FINAL BID REVIEW

Q. Please provide an overview of the Bids received by the Company.

A. On December 3, 2003, the Company received twelve bids, including two bids for the entire PPA Entitlement portfolio, and one bid for all but one of the Contracts.[3] None of the portfolio bids conformed to the Bid Instructions in that they were subject to internal approvals, further due diligence, or other such conditions.

Q. How did the Company evaluate the bids?

A. Throughout the months of December through March, negotiations continued with each of the bidders regarding specific aspects of their proposed financial and contractual terms. During this process, NSTAR Electric and CEA jointly and individually evaluated the bids with the objective of identifying those combinations of bids that offered the greatest mitigation of transition costs.

Written questions designed to clarify elements of various bids were sent to bidders throughout December and January, and responses were received and evaluated on a rolling basis. Based on CEA's and NSTAR Electric's evaluation of the bids, including the bidder responses to written questions, certain bidders were invited to participate in meetings and/or conference calls with the Company. During those meetings and calls,

---

[3] For the purposes of this discussion, these three bids are referred to as the "portfolio bids".

bidders were provided an opportunity to further clarify certain elements of their bids, and to propose potentially value-enhancing refinements. Based on those discussions, various bidders made specific improvements to their bids. That process of ongoing discussions and negotiations regarding the payment stream and transaction structure resulted in an agreement between NSTAR Electric and Pittsfield to terminate the Pittsfield Contracts.

Q. How did CEA develop its valuation of the PPA Entitlements?

A. Prior to the bid due date, CEA and NSTAR Electric developed an evaluation methodology under which bids would be compared to the Company's expected long-term costs under the respective contracts, and relative to the proposed terms of other bidders for the same contracts. To perform that analysis, CEA separately valued each PPA Entitlement to determine the total cost for the energy and capacity over the term of the agreement. Specific pricing and cost assumptions were made for each of the Contracts (the specific assumptions relating to the Pittsfield Contracts are described further below). Global assumptions regarding the market price of energy, capacity, and fuel were obtained from Henwood Energy Service Inc.'s ("Henwood") Northeast Electricity and Gas Price Outlook for Fall 2003, with updates in March and May, 2004 for years 2004 through 2006 ("Northeast Electric and Gas Price Forecast"). The above-market costs was calculated as the present value of the difference between the expected total cost under the Contract terms and the market value based on the Henwood forecast.

Q. Please describe in more detail the process used to evaluate the portfolio bids.

A. After the initial review of the portfolio bids, it was clear that one of the three portfolio bids was substantially nonconforming in its structure and contained pricing provisions that were considerably less attractive than the other portfolio bids. Consequently, our evaluation quickly turned to the remaining portfolio bids and viable combinations of contract-specific bids. Of the remaining two portfolio bids, one (herein referred to as "Bidder A") contained proposed pricing terms that were economically attractive, while the other bid ("Bidder B") contained proposed terms that were slightly above the expected above-market portfolio cost.[4] (Please note that Bidder B specifically excluded the Ocean State Power contract from its bid. See the Early Interest Letter contained in Exhibit NSTAR-RBH-3 for a summary of the Contracts. See Exhibit NSTAR-RBH-5 for a summary of the initial three portfolio bids.)

Q. How did you proceed with Bidders A and B?

A. As with all of the bidders in this process, CEA and the Company held a series of meetings and conference calls with Bidders A and B to address issues specific to their respective bids. In the course of those conversations, Bidder A brought forth a significant number of additional due diligence items, and introduced a series of internal accounting issues that would require several weeks to be resolved. Consequently, while Bidder A's portfolio bid was attractive on its face, it was unclear whether the bid would maintain its

---

[4] As noted elsewhere in my testimony, these comparative analyses were performed on a present-value basis.

economic viability. Our approach to Bidder A, therefore, was to promptly address the additional due diligence needs while the bidder continued to consider its internal accounting issues.

Bidder B's bid, while slightly high relative to the expected out-of-market cost (excluding the OSP contract), did not have the number or scope of contingencies contained in Bidder A's bid. In the case of Bidder B, therefore, CEA and the Company worked with the bidder to find ways either to reduce the cost of the portfolio bid, or to identify and remove specific contracts that appeared to have disproportionate effects on the bid price. Neither Bidder A nor Bidder B were counterparties to any of the Contracts and in both cases, the governing transaction document would have been the ETA.

Q. Please describe the remaining nine bidders.

A. Of the remaining nine bidders, four were existing Contract counterparties and bid only on the Contracts to which they were a counterparty. Three of the four counterparty bids appeared to be economically viable and in aggregate represented a significant portion of the portfolio's total estimated above-market cost. Those three bids, therefore, became strategic priorities. The remaining five bidders (none of whom was a counterparty) bid on a variety of Contract combinations. In three cases, the bidders bid only on the hydroelectric contracts. In one case, the bidder bid on two Contracts and the final bidder bid on only one contract. Three of the five non-portfolio, non-counterparty bids appeared to be economically attractive and also were considered to be strategic priorities. In each

case, CEA and the Company worked with the bidder of every economically viable bid to enhance the value of their respective bids.

Q. How did you then proceed with the bid evaluation and negotiations?

A. Since three of the four counterparty bids were economically attractive, CEA asked Bidders A and B to re-price their bids excluding various combinations of those three contracts. (By receiving bids with and without the contracts, CEA was able to discern the portfolio bidders' valuation of the excluded contracts.) In addition, given that three of the third-party, non-portfolio bids appeared to be economically viable, Bidders A and B provided additional re-pricing scenarios excluding various combinations of those Contracts. Based on that analysis, none of Bidder A or Bidder B's breakout bids exceeded the value of the combined counterparty bids. CEA and the Company therefore determined that it was prudent to focus our negotiations on the counterparty bidders. In the end, Bidder A was not able to resolve its accounting and due diligence issues and was dropped from the process; Bidder B was not able to materially improve either its portfolio or breakout bid price and also was dropped from the process.

Q. Please explain why the Pittsfield bid specifically was selected over the three portfolio bids.

A. As noted earlier, the Company's objective was to find that combination of bids that was most likely to create the greatest possible reduction in above-market costs associated with the Contracts. In order to make that assessment, the portfolio bidders were asked to disaggregate their bids into the several components that would allow for a side-by-side

comparison of bids for individual contracts and the portfolio taken as a whole. As a result of that assessment, CEA and the Company determined that the Pittsfield bid was the lowest viable bid and, in combination with other contract-specific bids, was therefore most likely to create the greatest reduction in above-market costs.

Q. Were other issues taken into consideration in evaluating the Pittsfield bid relative to the portfolio bids?

A. Yes. First, as noted earlier, all of the portfolio bids were subject to further internal approvals and due diligence. Consequently, even if the bids, which were effectively non-binding, produced reductions in above-market costs equal to those created by the Pittsfield bid, there was less certainty regarding the timing and pricing at which they might have closed. In addition, the Pittsfield termination agreement calls for the termination of the contract as opposed to the transfer of rights and obligations under an ETA (which would have been the principal transaction document for any of the portfolio bids). Since the termination agreement provides greater certainty as to the eventual economics of the transaction, all else being equal, the Company would prefer the termination agreement structure. Although Bidder A provided a non-binding proposal with slightly lower pricing, as noted earlier, that bidder was never able to present a final, binding proposal. Consequently, in addition to the more favorable structural elements of a termination agreement relative to an ETA, the Pittsfield bid also was the best viable bid in terms of pricing.

IV. THE TERMINATION OF THE PITTSFIELD CONTRACTS

Q. Please summarize the auction results as they relate to the Pittsfield Contracts.

A. As discussed earlier in my testimony, from October through December, 2003, the Company, through CEA, aggressively marketed the PPAs to a broad group of potential bidders, and provided selected, qualified bidders with substantial information and due diligence support regarding all aspects of the PPA Entitlements. On December 3, 2003, the Company received 12 bids for various combinations of the PPA Entitlements, including three bids for the complete portfolio. All three bids were subject to internal approvals, further due diligence, or other such conditions.

Of the two partially conforming bids, one bid included a breakout of the Pittsfield PPA Entitlements. That bid included a monthly payment stream plus an added lump sum payment from NSTAR Electric to the bidder. The other partially conforming portfolio bid proposed one monthly payment stream for all 24 PPA Entitlements without a breakout of the Pittsfield Contract.

Ongoing discussions and negotiations regarding pricing and ETA terms continued for several weeks. On April 13, 2004, Pittsfield submitted a proposal for the termination of the two Pittsfield Contracts. After extensive analysis and review (described later in my testimony), it was determined that the Pittsfield bid for the contract termination provided the greatest level of mitigation of the above-market costs associated with the Pittsfield Contracts.

Q. Please provide an overview of the Pittsfield Contracts.

A. The Pittsfield generating facility is located in Pittsfield, MA, and owned by Pittsfield Generating Company, L.P. The Pittsfield unit is a gas-fired, combined-cycle cogeneration facility consisting of three gas turbine generators combined with three heat recovery steam generators driving a fourth generator. The plant has a current summer capacity rating of 141 MW, and a winter capacity rating of 173 MW. NSTAR Electric has two PPAs for the output of the Pittsfield unit: one with Cambridge (Pittsfield 1) and one with Commonwealth (Pittsfield 2).

Q. Please describe the principal provisions of the Pittsfield 1 and Pittsfield 2 agreements.

A. The Pittsfield 1 and Pittsfield 2 agreements are nearly identical but for a pricing provision in Pittsfield 2. Both Pittsfield agreements have an eighteen-year term beginning on the actual in-service date of September 1, 1993 through December 31, 2011. Under each agreement, the Company is entitled to 17.2 percent of the summer and winter energy and capacity, or 24.3 MW and 29.8 MW of summer and winter capacity, respectively. Pricing under the Pittsfield 1 agreement is based on payments for delivered energy and capacity delivered to Cambridge and includes a transmission charge. As with the Pittsfield 1 agreement, the Pittsfield 2 agreement includes payments for delivered energy and capacity delivered to Commonwealth, but does not include the additional transmission charge. Both Pittsfield agreements contain other salient provisions, including assignment rights, and security provisions.

Q. Please describe the principal terms of the proposed Pittsfield termination.

A. As noted more fully by Mr. Lubbock, the Pittsfield transaction is a termination of the existing Pittsfield contracts whereby NSTAR Electric will make a series of lump-sum payments to Pittsfield for the termination of the NSTAR Electric contracts. On June 2, 2004, the Company and Pittsfield executed the Termination Agreements for the Pittsfield Contracts.

Q. What were the key assumptions relating to the valuation of the Pittsfield Contracts?

A. As noted earlier in my testimony, the pricing provisions under the Pittsfield Contracts include energy and capacity payments. Consequently, the primary variables in the contract evaluations are: (1) the market price of energy and capacity; (2) the contract price of energy and capacity; (3) the projected energy production; (4) fuel costs; (5) capital costs; and in the case of Pittsfield 1, (6) a transmission charge. To ensure internal consistency, the fuel, energy, and capacity, price projections were obtained from the same source, i.e., the Henwood forecast. Finally, CEA used a discount rate of 7.82 percent for this and all contract and bid evaluations.

Q. Given the assumptions described above, do you believe that there is a strong likelihood that the transaction will maximize the mitigation of transition costs?

A. Yes, I do. First, as discussed earlier, the Pittsfield bid is the result of an extensive and carefully implemented auction process in which bidders were given substantial amounts of data to analyze the contracts, and were provided many opportunities to revise and enhance their bids. As noted in Exhibit NSTAR-RBH-5, Pittsfield's bid was materially

better than any other bid for the Pittsfield Contracts (none of which was finalized), and on a present-value basis is approximately 10.7% below the expected out-of-market cost of the contract. Exhibit NSTAR-RBH-6 computes the Net Present Value of the reduction in above-market costs of the Termination Agreements by comparing the costs that will be incurred under the Termination Agreements to the above-market costs that would be incurred under the existing Pittsfield Contracts.

In many respects our calculation of the expected above-market costs is based on conservative estimations of underlying variables. For example, the Pittsfield units capacity factor recently has averaged approximately 27%. As a conservative approach to calculating the above-market costs for the two Pittsfield contracts, we have assumed in our current calculations a capacity factor of 37%. Utilizing a recent average capacity factor of 27% would have resulted in approximately 12.5% savings relative to the expected above-market costs (as opposed to the more conservative 10.7% savings noted above).

Q. What is your assessment of the proposed transaction's value?

A. For the reasons noted above, it is my conclusion that the proposed transaction is likely to result in approximately 10.7% percent reduction in above-market costs for the Pittsfield Contracts and that this reduction exists under a variety of market scenarios. In that regard, CEA performed a series of analyses under different power and fuel price scenarios and found that the proposed transaction continued to result in a reduction of the above-market costs of these contracts.

In summary, the Company ran a very competitive and unbiased auction process. NSTAR Electric announced its process to a broad market and aggressively marketed the PPA Entitlements for a substantial period. A high level of competition was maintained throughout the auction process and as a result, the Company received a series of strong, viable bids. I believe that the reduction in above-market costs in this transaction is a direct result of the competitive auction process that the Company established and implemented.

V. CONCLUSIONS

Q. Did the Company achieve the goals it established for this transaction?

A. Yes. As discussed earlier in my testimony, the Company established several objectives for this auction process, including:

- Minimizing the above-market costs associated with the PPA Entitlements;
- Developing, implementing and maintaining the most competitive auction process possible;
- Ensuring fair treatment of all bidders;
- Ensuring that the auction process was timely, efficient, and unbiased.

I believe that the Company achieved all its objectives by conducting a competitive auction that ensured the complete, uninhibited, non-discriminatory access to all data and information by all interested and qualified parties seeking to participate. Through this competitive process, NSTAR Electric has maximized the value of the PPAs and in so doing, has mitigated the above-market costs associated with the contracts for the benefit

of its customers. By all of those standards, the auction process and results have been successful.

Q. Does this conclude your testimony?

A. Yes, it does.

Robert B. Hevert, CFA
Concentric Energy Advisors, Inc.
313 Boston Post Road West, Suite 210
Marlborough, MA 01752

Mr. Hevert is an economic and financial consultant with broad experience in the energy industry. He has an extensive background in the areas of corporate strategic planning, energy market assessment, corporate finance, mergers, and acquisitions, asset-based transactions, asset and business unit valuation, market entry strategies, strategic alliances, project development, feasibility and due diligence analyses. Mr. Hevert has significant management experience with both operating and professional services companies.

REPRESENTATIVE PROJECT EXPERIENCE

Financial and Economic Advisory Services

Retained by numerous leading energy companies and financial institutions throughout North America to provide services relating to the strategic evaluation, acquisition, sale or development of a variety of regulated and non-regulated enterprises.

Specific services have included: developing strategic and financial analyses and managing multi-faceted due diligence reviews of proposed corporate M&A counter-parties; developing, screening and recommending potential M&A transactions and facilitating discussions between senior utility executives regarding transaction strategy and structure; performing valuation analyses and financial due diligence reviews of electric generation projects, retail marketing companies, and wholesale trading entities in support of significant M&A transactions.

Specific divestiture-related services have included advising both buy and sell-side clients in transactions for physical and contractual electric generation resources. Sell-side services have included: development and implementation of key aspects of asset divestiture programs such as marketing, offering memorandum development, development of transaction terms and conditions, bid process management, bid evaluation, negations, and regulatory approval process. Buy-side services have included comprehensive asset screening, selection, valuation and due diligence reviews. Both buy and sell-side services have included the use of sophisticated asset valuation techniques, and the development and delivery of fairness opinions.

Specific corporate finance experience while a Vice President with Bay State Gas included: negotiation, placement and closing of both private and public long-term debt, preferred and common equity; structured and project financing; corporate cash management; financial analysis, planning and forecasting; and various aspects of investor relations.

Representative non-confidential clients have included:

- Conectiv generation asset divestiture
- Eastern Utilities Associates (prior to acquisition by National Grid, PLC) generation asset divestiture
- Niagara Mohawk – sale of Niagara Mohawk Energy
- Potomac Electric Company generation asset divestiture

Representative confidential engagements have included:

- Buy-side valuation and assessment of merchant generation assets in Midwestern US
- Buy-side due diligence and valuation of wholesale energy marketing companies in Eastern and Midwestern US
- Buy-side due diligence of natural gas distribution assets in Northeastern US
- Financial feasibility study of natural gas pipeline in upper Midwestern US
- Financial valuation of natural gas pipeline in Southwestern US

Regulatory Analysis and Ratemaking

On behalf of electric, natural gas and combination utilities throughout North America, provided services relating to energy industry restructuring including merchant function exit, residual energy supply obligations, and stranded cost assessment and recovery. Also performed rate of return and cost of service analyses for municipally owned gas and electric utilities. Specific services provided include: performing strategic review and development of merchant function exit strategies including analysis of provider of last resort obligations in both electric and gas markets; and developing value optimizing strategies for physical generation assets.

Representative engagements have included:

- Performing rate of return analyses for use in cost of service analyses on behalf of municipally owned gas and electric utilities in the Southeastern and Midwestern US
- Developing merchant function exit strategies for Northeastern US natural gas distribution companies
- Developing regulatory and ratemaking strategy for mergers including several Northeastern natural gas distribution companies

Litigation Support and Expert Testimony

Provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues including the proposed transfer of power purchase agreements, procurement of residual service electric supply, the legal separation of generation assets, and specific financing transactions. Services provided also included collaborating with counsel, business and technical staff to develop litigation strategies, preparing and reviewing discovery and briefing materials, preparing presentation materials and participating in technical sessions with regulators and intervenors.

Energy Market Assessment

Retained by numerous leading energy companies and financial institutions nationwide to manage or provide assessments of regional energy markets throughout the US and Canada. Such assessments have included development of electric and natural gas price forecasts, analysis of generation project entry and exit scenarios, assessment of natural gas and electric transmission infrastructure, market structure and regulatory situation analysis, and assessment of competitive position. Market assessment engagements typically have been used as integral elements of business unit or asset-specific strategic plans or valuation analyses.

Representative engagements have included:

- Managing assessments of the NYPOOL, NEPOOL and PJM markets for major North American energy companies considering entering or expanding their presence in those markets
- Assessment of ECAR, MAPP, MAIN and SPP markets for a large US integrated utility considering acquisition of additional electric generation assets
- Assessment of natural gas pipeline and storage capacity in the SERC and FRCC markets for a major international energy company

Resource Procurement, Contracting and Analysis

Assisted various clients in evaluating alternatives for acquiring fuel and power supplies, including the development and negotiation of energy contracts and tolling agreements. Assignments also have included developing generation resource optimization strategies. Provided advice and analyses of transition service power supply contracts in the context of both physical and contractual generation resource divestiture transactions.

Business Strategy and Operations

Retained by numerous leading North American energy companies and financial institutions nationwide to provide services relating to the development of strategic plans and planning processes for both regulated and non-regulated enterprises. Specific services provided include: developing and implementing electric generation strategies and business process redesign initiatives; developing market entry strategies for retail and wholesale businesses including assessment of asset-based marketing and trading strategies; and facilitating executive level strategic planning retreats. As Vice President, Energy Ventures, of Bay State was responsible for the company's strategic planning and business development processes, played an integral role in developing the company's non-regulated marketing affiliate, EnergyUSA, and managed the company's non-regulated investments, partnerships and strategic alliances.

Representative engagements have included:

- Developing and facilitating executive level strategic planning retreats for Northeastern natural gas distribution companies
- Developing organization and business process redesign plans for municipally owned gas/electric/water utility in the Southeastern US
- Reviewing and revising corporate merchant generation business plans for Canadian and US integrated utilities
- Advising client personnel in development of business unit level strategic plans for various natural gas distribution companies

---

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
President

Navigant Consulting, Inc. (1997 - 2001)
Managing Director (2000 – 2001)
Director (1998 – 2000)
Vice President, REED Consulting Group (1997 – 1998)

REED Consulting Group (1997)
Vice President

Bay State Gas Company (1987 - 1997)
Vice President, Energy Ventures and Assistant Treasurer

Boston College (1986 - 1987)
Financial Analyst

General Telephone Company of the South (1984 - 1986)
Revenue Requirements Analyst

EDUCATION

M.B.A., University of Massachusetts, Amherst, 1984
B.S., University of Delaware, 1982

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Chartered Financial Analyst, 1991
Association for Investment Management and Research
Boston Security Analyst Society

PUBLICATIONS/PRESENTATIONS

Has made numerous presentations throughout the United States and Canada on several topics including:

- Generation Asset Valuation and the Use of Real Options
- Retail and Wholesale Market Entry Strategies
- The Use Strategic Alliances in Restructured Energy Markets
- Gas Supply and Pipeline Infrastructure in the Northeast Energy Markets
- Nuclear Asset Valuation and the Divestiture Process

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

Date	**Event**
July through October	Preliminary Marketing
October 1 – On-going	Finalize Confidentiality Agreements and qualify Bidders
Mid October	Confidential Offering Materials (Offering Memoranda, Draft ETA and Due Diligence Documentation) issued to Bidders
Oct. 17 – Nov. 21, 2003	Detailed due diligence, including meetings/conference calls with management and technical personnel, and confidential Q&A
November 6, 2003	Bid Instructions issued
December 3, 2003	Final Bids Received
Early December – On-going	Bid evaluation
Spring 2004	Agreement(s) executed, winner(s) announced, regulatory process commenced

October 1, 2003

[Contact]
[Title]
[Company Name]
[Address]
[Address]

Re: NSTAR PPA Entitlement Auction

Dear [Contact]:

On behalf of NSTAR Electric & Gas Corporation ("NSTAR" or the "Company"), the parent company of Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (collectively, the "NSTAR Companies"), we are writing to inform you of the Company's intention to sell or otherwise transfer its rights to 24 Power Purchase Agreements ("PPA Entitlements") totaling approximately 1,100 MW of capacity and associated energy through a competitive bidding process. NSTAR has retained Concentric Energy Advisors, Inc. ("CEA") to act as its advisor in the transaction. With this letter, we invite your company to participate in the competitive bidding process for all or any combination of the NSTAR Companies' PPA Entitlements.

Overview of the PPA Entitlements

The 24 PPAs represent a portfolio of entitlements in generation facilities that have a broad range of fuel types and operational characteristics, and have a variety of contract terms and pricing provisions. An overview of the PPAs is provided in Table 1.1 on the page which follows. As shown in Figure 1.1 below, the PPA Entitlements are strategically located throughout New England, presenting opportunities for sales within the integrated New England Power Pool ("NEPOOL") and into neighboring markets.

Figure 1.1

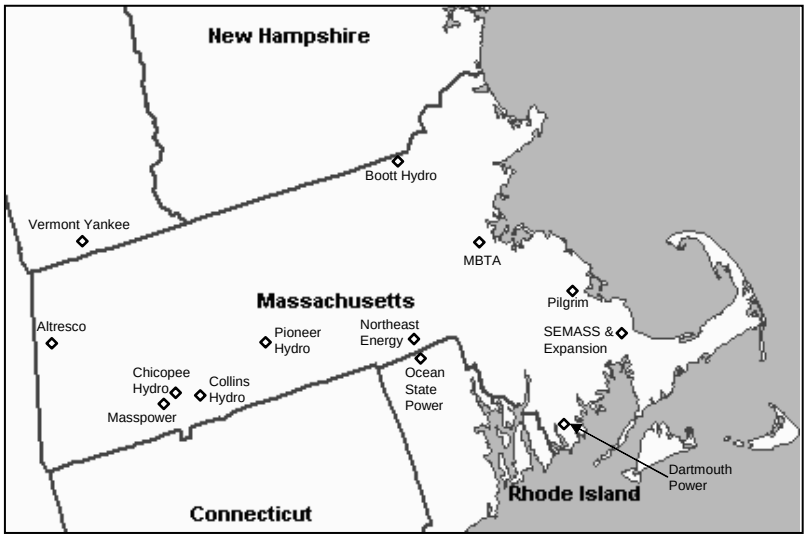


Table 1.1: Overview of the NSTAR Companies' PPA Entitlements

	Entitlement (MW)					
Unit & Contracting Entity	**Summer**	**Winter**	**Location**	**Expiration**	**Fuel**	**Technology**
Altresco-Pittsfield - CA	24.3	29.8	Pittsfield, MA	2011	Gas	CC Cogen
Altresco-Pittsfield - CO	24.3	29.8	Pittsfield, MA	2011	Gas	CC Cogen
Boott Hydro - CO	20.0	20.0	Lowell, MA	2023	Water	Hydro
Chicopee Hydro - CO	2.2	2.2	Chicopee, MA	2015	Water	Hydro
Collins Hydro - CO	1.3	1.3	N. Wilbraham, MA	2014	Water	Hydro
Dartmouth Power - CO	61.8	67.9	Dartmouth, MA	2017	Gas	CC
Masspower - BE	100.0	117.0	Indian Orchard, MA	2013	Gas	CC Cogen
Masspower 1 a - CO	25.7	30.0	See above	2008	Gas	CC Cogen
Masspower 2 - CO	25.7	30.0	See above	2023	Gas	CC Cogen
MBTA 1 - BE	25.0	33.4	South Boston, MA	2005	Jet Fuel	CT
MBTA 2 - BE	25.0	34.7	See above	2019	Jet Fuel	CT
NEA A - BE	123.5	153.0	Bellingham, MA	2016	Gas	CC Cogen
NEA B - BE	68.0	92.0	See above	2011	Gas	CC Cogen
NEA 1 - CO	22.9	28.3	See above	2016	Gas	CC Cogen
NEA 2 - CO	19.2	23.8	See above	2016	Gas	CC Cogen
Ocean State 1 - BE	63.7	74.5	Burrillville, RI	2010	Gas	CC Cogen
Ocean State 2 - BE	62.0	72.9	See above	2011	Gas	CC Cogen
Pilgrim - BE	230.8	230.8	See above	2004	Nuclear	Nuclear
Pilgrim Municipals - BE	24.4	24.4	Plymouth, MA	2004	Nuclear	Nuclear
Pilgrim - CO	36.0	36.0	See above	2004	Nuclear	Nuclear
Pioneer Hydro - CO	1.3	1.3	See above	2014	Water	Hydro
SEMASS - CO	46.2	50.7	Rochester, MA	2015	Refuse	Steam Boiler
SEMASS Expansion - CO	20.9	24.3	See above	2015	Refuse	Steam Boiler
Vermont Yankee - CA	12.7	13.2	Vernon, VT	2012	Nuclear	Nuclear
Total MW	**1,066.7**	**1,221.1**				

CA = Cambridge Electric Light Company
CO = Commonwealth Electric Company
BE = Boston Edison Company
CC = Combined Cycle
CT = Combustion Turbine

NSTAR will consider bids for all PPAs, any individual PPA, or any combination of PPAs. The NSTAR Companies anticipate transferring the PPAs to the winning bidder(s) through an Entitlement Transfer Agreement ("ETA"), under which all rights and obligations under the PPAs will be transferred to the winning bidder(s) for the remaining term of the PPAs.

Overview of Competitive Bidding Process and Schedule
NSTAR intends to conduct a single-stage bidding process, which will provide all bidders the opportunity to perform detailed due diligence and will culminate with the submission of bids in mid-November. An overview of the major milestones in the competitive bidding process is provided in Table 1.2 below. Please note that the competitive bidding process and schedule described herein represent the Company's best current estimate and are subject to change. Bidders will be notified promptly of any changes to the bidding process or schedule.

Table 1.2 Bidding Process Milestones

Date	Event
October 1 – On-going	Finalize Confidentiality Agreements and qualify Bidders
Early October	Confidential Offering Materials (Offering Memoranda, Draft ETA and Due Diligence Documentation) issued to qualified bidders
Oct. 6 – Nov. 7, 2003	Detailed due diligence, including meetings/conference calls with management and technical personnel, and confidential Q&A
October 24, 2003	Bid Instructions issued
November 14, 2003	**Bids due**
December 3, 2003	Bid evaluation, short list notified and negotiations
December 31, 2003	Agreement(s) executed, winner(s) announced, regulatory process commenced

Parties who are interested in bidding on any of the PPA entitlements must submit to CEA a Statement of Qualifications as well as an executed Confidentiality Agreement, each of which are enclosed with this letter. Submissions should be made as quickly as possible to:

Robert B. Hevert
Concentric Energy Advisors, Inc.
313 Boston Post Road West, Suite 210
Marlborough, MA 01752
(508)263-6204 phone
(508) 303-3290 fax
bhevert@ceadvisors.com

Upon the submission of an executed Confidentiality Agreement, bidders will be issued the Company's confidential PPA Entitlement Offering Materials, including the Offering Memorandum, draft ETA, Due Diligence Documentation (e.g., copies of contracts and invoices), and spreadsheet models of each PPA. Qualified bidders will be provided the opportunity to perform detailed due diligence, including meetings with Company representatives.

The NSTAR Companies expressly reserve the right, in their sole and absolute discretion, to negotiate with one or more parties at any time and to enter into a definitive agreement for a transaction involving all or any portion of the PPAs without prior notice to bidders. The NSTAR Companies, and CEA on their behalf, also reserve the right at any time, to modify any of the rules or procedures set forth herein or any other procedure, without prior notice and without assigning any reason, or to terminate the process contemplated by this letter.

All requests for further information regarding the PPAs should be made to CEA. Employees of the NSTAR Companies or their affiliates or subsidiaries should not be contacted regarding this transaction.

Thank you for your consideration. We look forward to working with you on this exciting opportunity.

Sincerely,

CONCENTRIC ENERGY ADVISORS, INC.

Robert B. Hevert
President

Enclosures:

Confidentiality Agreement
Request for Qualifications

CONFIDENTIALITY AGREEMENT

This AGREEMENT is entered into as of the _____ day of _____, 2003 by and between Boston Edison Company, Commonwealth Electric Company and Cambridge Electric Light Company, each being a Massachusetts corporation with a principal place of business at 800 Boylston Street, Boston, Massachusetts ("NSTAR Companies"), and _____, a _____ _____ with a principal place of business at _____ ("Counterparty"). NSTAR Companies and Counterparty are collectively referred to as "the Parties", and also individually as the "Party", herein.

Preamble

The Parties desire to engage process to value certain power purchase agreements ("PPAs") in considering the possible sale of those PPAs ("Possible Sale") by NSTAR Companies to Counterparty.
In the course of this process the parties intend to exchange confidential and proprietary information, as hereinafter described.

Agreement

In consideration of the covenants set forth herein, the Parties agree as follows:

1. EXCHANGE OF CONFIDENTIAL INFORMATION

1.1 The Parties agree to exchange confidential and/or proprietary information that may include business plans, financial data, load data, supply and resource data, contractual terms, pricing, proposals and other market-sensitive information, all of the foregoing being referred to herein as "Confidential Information." The Confidential Information may be conveyed in the course of the discussions between the parties, or in hard copy and/or electronic form. A Party providing Confidential Information under this Agreement is referred to herein as the "Disclosing Party," and the party receiving Confidential Information is referred to as "the Recipient."

2. RELIANCE ON INFORMATION

2.1 The parties acknowledge that neither NSTAR Companies nor their representatives nor any of the respective officers, partners, directors, employees, agents or controlling persons of NSTAR Companies or such representatives makes any express or implied representation or warranty as to the accuracy or completeness of any Confidential Information, and Counterparty agrees that none of such persons shall have any liability to Counterparty or its representatives or to any other person relating to or arising from Counterparty's use of any Confidential Information or for any errors therein or omissions there from. Counterparty agrees that it is not entitled to rely on the accuracy or completeness of any Confidential Information and that it shall be entitled to rely solely on such representations and warranties regarding Confidential Information as may be made in any final acquisition agreement relating to the Possible Sale, subject to the terms and conditions of such agreement.

3. PROTECTION OF INFORMATION

3.1 The Recipient acknowledges the proprietary rights of the Disclosing Party in and to the Confidential Information. The Parties further acknowledge and agree that no license or other proprietary interest in the Confidential Information is granted or transferred to Recipient hereby, or by the receipt of such Information by Recipient. The Recipient also acknowledges and agrees that the Confidential Information is furnished to it on a confidential basis, for the sole and exclusive use of the Recipient in connection with the aforementioned discussions, and the Recipient agrees that it will not use the Confidential Information for any other purpose nor publish, disclose or otherwise divulge the Confidential Information to any person, entity, or firm without the prior written consent of the Disclosing Party, except as provided herein. The Recipient shall permit access to the Information only to those of its and affiliates' own employees, officers, directors and consultants who have a need to know for purposes of the referenced discussions.

3.2 The copies made of said Confidential Information must be returned or destroyed upon the request of Disclosing Party. The Recipient shall upon request confirm in writing by affidavit that it has returned the Confidential Information or that all copies of the Information have been destroyed.

3.3 If the Recipient is requested by a governmental or judicial body to release to such body any Confidential Information, the Recipient shall notify the Disclosing Party of such request as soon as practicable to allow the Disclosing Party to seek an appropriate protective order. Absent a protective order, if required by order of a governmental or judicial body, the Recipient may, subject to protest and appeal by either party, release to such body the Confidential Information required by such order, provided that the Recipient shall use its best efforts to cause that body to treat such Confidential Information in a confidential manner, and prevent such information from becoming a part of the public domain.

3.4 Except as otherwise provided herein, in performing its obligations under this Article 2, the Recipient shall employ at its own cost procedures no less restrictive than the strictest procedures used by the Recipient to protect its own confidential information to prevent unauthorized disclosure or use of Confidential Information provided hereunder.

3.5 The Recipient agrees that remedies at law may be inadequate to protect Disclosing Party in the event of a breach of this Agreement, and the Recipient hereby in advance agrees to the granting of injunctive relief in favor of the Disclosing Party, to prevent the continuation of any such breach without proof of actual damages.

3.6 This Article 3 shall survive termination of this Agreement.

4. LIMITATIONS ON OBJECTIONS

4.1 The parties acknowledge the collective benefit to all persons participating in the Possible Sale process of finality in the process and of NSTAR Companies providing Counterparty with access to the Confidential Information pursuant to this letter agreement, the sufficiency of which consideration is hereby acknowledged, Counterparty further agrees (i) not to object in any regulatory proceedings seeking authorization relating to any sale of a power purchase agreement by NSTAR Companies and (ii) not to seek from any regulatory agency or any court any order, judgment or decree that Counterparty's bid was the "highest" or "best" bid, that Counterparty should have been chosen as the successful bidder in the process, that NSTAR Companies erred in their evaluation of the price, terms or conditions of Counterparty's bid or any bid of any other participant in the process as compared to

the chosen successful bidder's bid (if there be one), or that NSTAR Companies otherwise exercised in their discretion in connection with this process in an inappropriate manner.

5. GENERAL CONDITIONS

5.1 The term of this Agreement shall commence as of the date hereof and shall continue for a period of three (3) years thereafter, and may be extended from month to month by written agreement.

5.2 No waiver, consent, or modification of any of the provisions of this Agreement shall be binding unless in writing and signed by duly authorized representatives of both of the parties hereto, and no waiver by any party of any default of the other shall be deemed to be a waiver by such party of any other default.

5.3 If any court shall deem any provision of this Agreement unenforceable by reason of the extent or duration of the covenants contained herein or for any other reason, then the parties agree that the court shall reduce or modify as appropriate the provision hereof that is unenforceable so as to render such provision (and/or the remaining provisions of this Agreement) enforceable, and that this Agreement as so modified shall otherwise remain in full force and effect in accordance with its terms.

5.4 Confidential Information is provided hereunder without warranty or representation by the Disclosing Party as to the accuracy or completeness thereof.

5.5 Except to the extent set forth in this Confidentiality Agreement, Counterparty agrees that until a final acquisition agreement regarding the Possible Sale has been executed by the Parties, neither the nor its representatives are under any legal obligation and shall have no liability to Counterparty of any nature whatsoever with respect to the Possible Sale by virtue of this agreement or otherwise.

5.6 This Agreement represents the entire Agreement between the parties with respect to the subject matter set forth herein, may only be amended by a writing signed by the parties, shall inure to and be binding upon the parties and their respective successors and assigns.

5.7 This Agreement and the rights and obligations of the parties hereunder shall in all respects be governed by and construed and enforced in accordance with the law of the Commonwealth of Massachusetts.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed as of the date first above-stated.

BOSTON EDISON COMPANY
COMMONWEALTH ELECTRIC COMPANY
CAMBRIDGE ELECTRIC LIGHT COMPANY

_____

By:_____ By:_____

Title:_____ Title:_____

NSTAR PPA AUCTION
REQUEST FOR QUALIFICATIONS

Parties that intend to submit Bids for the 24 Power Purchase Agreements ("PPA Entitlements") totaling approximately 1,100 MW of capacity and associated energy must provide a complete Qualifications Package. Upon receipt and approval of the Qualifications Package, the interested party will become a "Qualified Bidder" as described in the Confidential Offering Memorandum. Qualifications Packages must be received no later than October 31, 2003 and should be organized as described below:

1. Identification of Parties: Each prospective Bidder must identify the entities that will submit their Bid. This information must include:
    a. The name and role of each entity included in the bidding group;
    b. Primary and secondary contact information for individuals responsible for submitting Bids;
    c. Name and contact details for any advisors retained in connection with the bidding process;
    d. Any and all anticipated partners; and
    e. If known, the source of funds and a general description of the anticipated transaction financing.

2. Identification of Assets:
    a. For the purpose of assessing potential market power issues, each prospective Bidder must identify generating assets, both physical and contractual, that it owns, operates or controls within NEPOOL.

3. Financial Qualifications: NSTAR will qualify prospective Bidders based in part on their demonstrated ability to finance the proposed transaction. NSTAR will not accept Bids that contain financing contingencies. For the purposes of establishing financial capability, prospective Bidders must, to the extent available, for each bidding group, submit all reports filed with the Securities and Exchange Commission pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, and the rules promulgated thereunder for the most recent two (2) fiscal years. If the prospective Bidder is not required to file the reports noted above, audited or certified financial statements for the same periods must be provided.

4. Conflicts of Interest: Each prospective Bidder must briefly describe any known material conflicts of interest between itself or any member of its bidding group and NSTAR including, but not limited to:
    a. Any litigation involving the prospective Bidder or any member of the bidding group and any of the NSTAR Companies;
    b. Any claims asserted by the prospective Bidder or any member of the bidding group against any of the NSTAR Companies; and
    c. Any indebtedness of the prospective Bidder or any member of the bidding group to any of the NSTAR Companies as a borrower, guarantor or otherwise.

5. Necessary Approvals: Prospective Bidders should indicate all internal and external approvals required to close the transaction. Bids subject to further internal approvals will not be accepted.

Prospective Bidders must provide the information requested herein to NSTAR through its advisors, Concentric Energy Advisors ("CEA"), at the addresses shown below no later than Friday, October 31, 2003. NSTAR and CEA will review the Qualifications Package upon receipt. *Prospective Bidders must be qualified by NSTAR in order to submit Bids.*

Please send two copies of the Qualifications Package to the address shown below:

Robert Hevert
President
Concentric Energy Advisors
313 Boston Post Road West, Suite 210
Marlborough, MA 01752
Phone: (508) 263-6204
Fax: (508) 303-3290
Email: bhevert@ceadvisors.com

Please direct any questions regarding this or any other aspect of this transaction to Robert Hevert at the number noted above.

CONCENTRIC ENERGY ADVISORS

313 Boston Post Road West, Suite 210
Marlborough, MA 01752
508.263.6200 • 508.303.3290 *fax*
www.ceadvisors.com

PRIVILEGED AND CONFIDENTIAL

November 6, 2003

Dear:

On behalf of the NSTAR Electric & Gas Corporation ("NSTAR" or the "Company"), the parent company of Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company (collectively, the "NSTAR Companies"), Concentric Energy Advisors, Inc. ("CEA") is writing to inform you of the timing and procedures for submitting final bids ("Bids") regarding the transfer of entitlements to certain power purchase agreements ("PPAs").

FINAL BID DUE DATE AND CONCLUSION OF DUE DILIGENCE

Final Bids will be due at 12:00 noon EST on Tuesday, November 25, 2003. The deadline for submitting remaining due diligence questions and for participating in meetings or conference calls with NSTAR management will be Friday, November 21, 2003.

1. ***Bid Form:*** Bidders should complete and provide the PPA Entitlement Bid Form for each PPA for which a bid is being submitted. Please note that bids will be evaluated based on proposals submitted as of November 25, 2003. As noted in Paragraph 6 below, Bidders should assume a closing date of April 1, 2004. *To the extent that bids must be periodically re-marked to reflect changes in market conditions prior to the closing date, or changes in the date of the closing, bidders should provide the formula and indices that would be used to adjust such bid. Please note that both the complexity of re-marking formulas and the level of re-pricing will be factors considered by the Company in its evaluation of bids.*

2. ***Confirmation of Bidding Group:*** List all parties in the bidding group (as defined in the Request for Qualifications). If there have been any changes to the bidding group since the qualification process, such changes must be clearly identified.

3. ***Bidders may form consortia:*** In such cases, CEA must be promptly notified and a lead Bidder must be designated for the purpose of communications and possible negotiations.

4. ***Identification of Advisors:*** Identify all advisors to the Bidder, along with their respective roles.

5. ***Identification of Interest:*** Clearly identify the PPAs for which the Bid is being submitted. If separate Bids are being submitted for different PPAs or combinations of PPAs, clearly identify each such Bid and the PPAs to which it applies.

6. ***Pricing Options:*** For each PPA Entitlement being sought, clearly state the pricing Option and amounts for that PPA. For the purpose of the Bid, the effective date of the ETA should be assumed to be April 1, 2004. As noted above, bidders must provide, their proposed adjustment formulas and underlying indices intended to reflect changes in market prices or the timing of closing.

7. ***Approvals:*** Provide a list of regulatory, and/or governmental and other approvals required to close the transaction(s) contemplated, the process for obtaining and estimated time required to secure such approvals. ***Please note that Bids contingent upon board, shareholder or other internal approvals may be rejected. All proposals must be signed by an official authorized to bind the Bidder.***

8. ***Financial Qualifications:*** Each Bidder or its unconditional guarantor is required to demonstrate that it meets minimum credit criteria, including maintenance of an investment grade credit rating and a minimum capitalization threshold sufficient to support its bid through the term of the longest-lived PPA Entitlement in its bid package. To that end, the Bidder may be required to provide a stand-by letter of credit or similar security instrument provided by an investment grade commercial bank. The term of the security instrument together with detailed security provisions are described in the Transaction Agreements.

   Bidders must explain how the required financial security would be provided and the status of any documentation required for the Bidders to provide such security. In addition, if the Bidder proposes to provide financial assurance through a parent and/or affiliate, the Bidder should submit similar information with respect to that entity.

   To the extent a special purpose entity ("SPE") is anticipated, the Bidder must provide the identity and relationship between the SPE and the entity providing the necessary credit support and indemnities. As stated above, the Bidders must identify the entity providing credit support for the proposed transaction and ongoing financial obligations, as well as its relationship to the Bidder or bidding group.

9. ***Exceptions to the Entitlement Transfer Agreement:*** To the extent a Bidder wishes to propose bid-enhancing exceptions to the Entitlement Transfer Agreement, the Bidder must include an electronically marked copy of the documents. All proposed language additions, deletions, or changes should be clearly marked and should be indicated in the relevant place in the text of the documents. The extent and nature of the proposed exceptions will be taken into consideration in evaluating Bids. Significant deviations from the terms as stated in the Transaction Agreements will be viewed negatively in the Bid evaluation process.

Three paper copies of your entire Bid package and one electronic copy (MS Word format) of any proposed modifications to the Entitlement Transfer Agreement, and the PPA Entitlement Bid Form should be delivered by Tuesday, November 25, 2003 12:00 noon EST to:

Concentric Energy Advisors
313 Boston Post Road West, Suite 210
Marlborough, MA 01752
Attention: Robert B. Hevert
Telephone: 508.263.6204

The NSTAR Companies intend to select the successful bidder(s), with the assistance of CEA, as soon as practicable following the receipt of Bids. NSTAR expressly reserves the right, in its sole and absolute discretion, to negotiate with one or more Bidders at any time during this process. All Bidders will be notified regarding the outcome of this process if, when and as appropriate. NSTAR, and CEA on its behalf, reserves the right to terminate the bidding and solicitation process and to modify any of the rules or procedures set forth herein, or any other procedures, at any time without prior notice and without assigning any reason. All Bidders will be notified of any such modifications if, when and as appropriate. CEA will continue as the point of contact regarding the Bid submission process, including continuing due diligence matters.

If you have any questions about these instructions, or require any additional information regarding this bidding process, please contact your Bidder Representative. Finally, please note that the existence and content of this letter, and the existence, content and status of any Bid are subject to the Confidentiality Agreement previously executed by you.

On behalf of the NSTAR Companies, thank you for your continuing interest in this process.

Regards,

CONCENTRIC ENERGY ADVISORS, INC.

Robert B. Hevert
Phone: 508.263.6204
Email: bhevert@ceadvisors.com

Enclosures: Attachment 1: PPA Entitlement Bid Form

PPA ENTITLEMENT BID FORM

Bidders should provide three (3) hard copies, and one electronic copy of this bid form for each PPA.

Name of Bidding Group: _____

Name of PPA Entitlement: As provided in Section 5 of the Offering Memorandum _____

Pricing: Pricing for each of the PPA Entitlements can be structured in either of two ways. Option 1 is a lump sum payment from the Bidder to NSTAR (positive number) or from NSTAR to Bidder (negative number) based on NSTAR paying the indicated monthly support payments for each contract. NSTAR will provide each Bidder a schedule of monthly support payments for the term of each of the PPAs. Bidders should evaluate the PPA based on that support payment and propose a price they would pay (a positive number) or payment they would require from NSTAR (a negative number) to assume the rights and obligations of the PPA pursuant to the ETA. Option 2 is available for contracts with energy only pricing under the PPA (no fixed charges). Under Option 2 bidders should indicate the price per megawatt hour they would pay to NSTAR for energy delivered pursuant to an entitlement transfer of that PPA.

All bids should be for the full remaining term of any PPA and for the full output associated with any PPA. All bids are to be quoted in US dollars.

Pricing Option 1: Fixed <u>Monthly</u> Entitlement Support Payment from NSTAR to the Bidder:

Year	MONTHLY Support Payment	Year	MONTHLY Support Payment
2004	(To Be Supplied NSTAR)	2016	(To Be Supplied NSTAR)
2005	(To Be Supplied NSTAR)	2017	(To Be Supplied NSTAR)
2006	(To Be Supplied NSTAR)	2018	(To Be Supplied NSTAR)
2007	(To Be Supplied NSTAR)	2019	(To Be Supplied NSTAR)
2008	(To Be Supplied NSTAR)	2020	(To Be Supplied NSTAR)
2009	(To Be Supplied NSTAR)	2021	(To Be Supplied NSTAR)
2010	(To Be Supplied NSTAR)	2022	(To Be Supplied NSTAR)
2011	(To Be Supplied NSTAR)	2023	(To Be Supplied NSTAR)
2012	(To Be Supplied NSTAR)	2024	(To Be Supplied NSTAR)
2013	(To Be Supplied NSTAR)	2025	(To Be Supplied NSTAR)
2014	(To Be Supplied NSTAR)	2026	(To Be Supplied NSTAR)
2015	(To Be Supplied NSTAR)		

NSTAR PPA ENTITLEMENT
BID FORM
PAGE TWO

Pricing Option 2: Fixed Price per MWH delivered under the contract:

Year	$/MWH	Year	$/MWH
2004		2016	
2005		2017	
2006		2018	
2007		2019	
2008		2020	
2009		2021	
2010		2022	
2011		2023	
2012		2024	
2013		2025	
2014		2026	
2015			

Is this bid separable from other PPA Entitlement bids made by Bidder? _____ (Yes/No)
If No, indicate the specific PPA Entitlements that should be considered as a bundle:

To the extent that any bid is subject either to a re-mark to market between the date of submission and the date of closing, or to a price adjustment based on variations in the closing date, please provide the formula specifying how the bid would be adjusted to reflect any such changes. For the purposes of this adjustment formula please assume that all PPA transfers would occur on the first day of the month and that the closing would occur between February 1, 2004 and April 1, 2004. Further, for all proposed re-marks, clearly indicate the starting value used to develop the bid and the published index or indices that provide the basis for the change.

Bidders should be aware that NSTAR will require any re-marking to be based on publicly available indices or data sources; and the Company strongly prefers that re-marking be kept to as low a level as possible.

Initial Pittsfield Bids - December 3, 2003

(In $1,000's)	Portfolio Bid	Pittsfield
Bidder A	$ (1,717,683)	
Bidder B [1]	$ (1,948,029)	$ (143,520)
Bidder C	$ (3,458,160)	$ (154,060)
Bidder D		$ (105,400)
CEA/NSTAR Valuation	$ (1,892,000)	$ (122,205) [4]

Final Bids - Spring 2004 [2]

	Portfolio Bid	Pittsfield
Bidder A [3]		N/A
Bidder B		N/A
Bidder C		N/A
Bidder D		$ (71,847)
	$ (1,877,609)	$ (80,444) [5]

[1] Portfolio bid excludes the OSP Contracts
[2] Includes updated market prices
[3] Bidder A did not provide a final binding bid
[4] CEA/NSTAR initial valuation based on a April 2004 PV
[5] CEA/NSTAR final valuation based on October 2004 PV

(in $1,000's)

Line		2004	2005	2006	2007	2008	2009	2010	2011
1	Cambridge Electric						Capital Costs [6]		
2	Projected Market Price	$957.49	$3,979.75	$3,466.72	$3,432.72	$3,593.25	$3,721.68	$3,922.28	$4,143.30
3	Projected Contract Cost	$4,230.51	$16,171.32	$16,334.26	$15,328.24	$10,271.16	$3,721.68	$3,922.28	$4,143.30
4	Above Market Amount	$ (3,273)	$ (12,192)	$ (12,868)	$ (11,896)	$ (6,678)	$ -	$ -	$ -
5	Present Value [1]	$ (40,294)							
6									
7									
8	Commonwealth Electric								
9	Projected Market Price	$926.90	$3,817.37	$3,346.39	$3,138.36	$3,238.19	$3,334.96	$3,492.46	$3,631.84
10	Projected Contract Cost	$4,112.77	$15,661.87	$15,667.19	$14,913.44	$11,084.36	$3,334.96	$3,492.46	$3,631.84
11	Above Market Amount	$ (3,186)	$ (11,844)	$ (12,321)	$ (11,775)	$ (7,846)	$ -	$ -	$ -
12	Present Value [1]	$ (40,151)							
13									
14									
15									
16	Total PV of Above Market Amount [1]	$ (80,444)							
17									
18	Pittsfield Termination Price	$ (71,847)							
19	Reduction in Above Market	10.69%							
20									
21									
22									
23									
24									
25									

NOTES

[1] Present value at 7.82% as of 10/1/04

Cambridge Projected Contract Cost Summary

Line	Year	Total KWh [1]	Energy Charge [2]	Capacity Charge [3]	Availability Adjustment [4]	Gas Transportation Charge [5]	Capital Costs [6]	Transmission Charge [7]	Total
1	2004								
2	2005								
3	2006								
4	2007								
5	2008								
6	2009								
7	2010								
8	2011								
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									

REDACTED

Commonweath Projected Contract Cost Summary

Line	Year	Total KWh [1]	Energy Charge [2]	Capacity Charge [3]	Availability Adjustment [4]	Gas Transportation Charge [5]	Capital Costs [6]	Total
1	2004							
2	2005							
3	2006							
4	2007							
5	2008							
6	2009							
7	2010							
8	2011							
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								

REDACTED

Henwood Power and Fuel Forecast Market Prices [1]
Average Annual Prices (Nominal $)

						Capital Costs [6]
		Power ($/MW)		**Fuel ($/Mmbtu)**		
Line	Year	NEMA 24/7	SEMA 24/7	Gas	Oil	Coal
1	2004					
2	2005					
3	2006					
4	2007					
5	2008					
6	2009					
7	2010					
8	2011					
9						
10						
11						
12						
13						

REDACTED

Projected Market Price Summary

Line	Year	Total KWh [1]	NEMA Prices ($/MWh)	SEMA Prices ($/MWh)	Cambridge Market Prices [2]	Commonwealth Market Prices [3]
1	2004					
2	2005					
3	2006					
4	2007					
5	2008					
6	2009					
7	2010					
8	2011					
9						
10						
11						
12						
13						
14						
15						

REDACTED