nationalgrid

Raquel J. Webster
Senior Counsel

March 17, 2016

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4592 - National Grid's Proposed FY 2017 Electric Infrastructure, Safety, and Reliability Plan
<u>Response to Record Request No. 3</u>

Dear Ms. Massaro:

I have enclosed National Grid's[1] response to the PUC's Record Request No. 3 in the above-referenced docket. Because the attachments to Record Request No. 3 are voluminous, I have enclosed the Company's response to Record Request No. 3 and Attachments RR-3(a), RR-3(b), and RR-3(c) in the enclosed five CD-ROMs.

This transmittal completes the Company's responses to the PUC's record requests in this docket.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4592 Service List
Leo Wold, Esq.
Steve Scialabba, Division
Greg Booth, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

Certificate of Service

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

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

March 17, 2016
Date

Docket No. 4592 National Grid's Electric Infrastructure, Safety and Reliability Plan FY 2017 - Service List as of 1/21/16

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File an original & nine copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107

Record Request No. 3

Request:

Town of New Shoreham Project - Please provide an update on the construction and costs of the transmission line between Block Island and the mainland, including an update on the status and costs of the Wakefield substation. Please provide a copy of any tariffs that have been filed with and approved by FERC relating to cost recovery and allocation. Please provide a categorization of costs that will be collected through distribution rates and through transmission rates. Please provide each stage of costs so far from investment grade to current grade.

Response:

The Town of New Shoreham Project is a public policy project, which is authorized and directed by Rhode Island law. The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits the Company[1], at its option, to own, operate, or otherwise participate in the transmission cable project. Deepwater Wind's Block Island Wind Farm will interconnect to a new substation that is owned by the Company on Block Island. Deepwater Wind is responsible for paying all directly assigned facilities (sole use facilities), including those facilities required to connect to the Company's New Shoreham interconnection substation on Block Island. Similarly, Block Island Power Company is responsible for funding its directly assigned facilities (sole use facilities) on Block Island to connect to the new New Shoreham substation on Block Island. The new substation on Block Island will be connected to the Company's existing power system at Wakefield substation.

Pursuant to R.I. Gen. Laws § 39-26.1-7, the costs of the new transmission cable system will be calculated in the same manner that other transmission costs are calculated in Rhode Island for Local Network Service under the jurisdiction of the Federal Energy Regulatory Commission (FERC). The costs will be allocated consistently with R.I. Gen. Laws § 39-26.1-7 through transmission rates to the Company and Block Island Power Company through the "Block Island Transmission Surcharge." Because the upgrades to the Wakefield substation are to existing distribution assets, this portion of the work is "distribution" and recovered through the Electric Infrastructure, Safety, and Reliability Plan as a component of retail rates

The estimated cost of the facilities associated with the Block Island Transmission Surcharge is $107.2 million (Submarine Cable, $76.2 million; Land Cable, $20 million; Substations ($14.6 million) and considered a Planning Grade Estimate (+/- 25%). The estimated cost of Transmission assets is $106.0 million, and the estimated cost of Distribution Assets (Wakefield

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

Upgrades) is $ 1.2 million. The construction of this project was awarded to three vendors: LS Cable America (awarded 2/2015), J.H. Lynch (awarded 1/2016), and McPhee Electric (awarded 12/2015) for the Submarine Cable, Land Cable, and Substations projects, respectively. The 20-mile Submarine Cable was built in South Korea, and is expected to be received in the United States by the end of March 2016.

The following tariffs and agreements filed with FERC enable recovery of the transmission costs for the project.

- **New England Power's FERC Electric Tariff No. 1 and associated Integrated Facilities Agreement**

  Tariff No. 1 reflects an integrated facilities arrangement between New England Power Company (NEP) and The Narragansett Electric Company (Narragansett). NEP acts as the transmission provider for itself and its New England distribution affiliates, including Narragansett.

  Under the Integrated Facilities Agreement, Service Agreement No. 23, under NEP's Tariff No. 1, NEP will compensate Narragansett for the costs of the Block Island submarine project that will be owned by Narragansett. In turn, NEP will allocate these costs to Narragansett and Block Island Power Company through the Block Island Transmission System Surcharge as described in the Local Service Agreements section below.

  Please see Attachment RR-3(a) on CD-ROM for an Amendment to Service Agreement No. 23 under NEP's Tariff No. 1 accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2493-000.

- **Local Service Agreement among NEP, The Narragansett Electric and ISO-New England (ISO-NE) under Schedule 21 to the ISO-NE Open Access Transmission Tariff (OATT)**

  The Company's Local Service Agreement, under Schedule 21 of the ISO-NE OATT, includes the Block Island Transmission System Surcharge as a mechanism to allocate the costs of the submarine cable to The Narragansett Electric Company and the Block Island Power Company.

See Attachment RR-3(b) on CD-ROM for the First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT. This was accepted by FERC by delegated letter order on June 22, 2015 in Docket No. ER15-1466.

- **A Local Service Agreement among NEP, Block Island Power Company, and ISO-NE under Schedule 21 to the ISO-NE Open Access Transmission Tariff (OATT)**

  This Local Service Agreement, under Schedule 21 of the ISO-NE OATT, outlines the terms and conditions for the provision of wholesale transmission service to Block Island Power Company in addition to the cost recovery of directly assigned facilities, including equipment in the New Shoreham Substation and overhead tap to Block Island Power Company's substation.

  The Local Service Agreement also includes the Block Island Transmission System Surcharge as a mechanism to allocate the costs of the submarine cable to The Narragansett Electric Company and the Block Island Power Company. Please see Attachment RR-3(b) on CD-ROM for the First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT. This was accepted by the Commission by delegated letter order on June 22, 2015, in Docket No. ER15-1466.

- **A Large Generator Interconnection Agreement with Block Island Wind**

  The Interconnection Agreement with Block Island Wind outlines the terms and conditions of the generator interconnection, and also the cost recovery of directly assigned facilities, including equipment in the New Shoreham Substation.

  Please see Attachment RR-3(c) on CD-ROM for the Agreement that FERC accepted by delegated letter order on September 2, 2014 in Docket No. ER14-2496-000.

ALSTON&BIRD LLP

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

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July 24, 2014

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

Re: New England Power Company
Docket No. ER14-______-000
Filing of Sixth Revised Service Agreement No. 23
with The Narragansett Electric Company

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") submits for filing Sixth Revised Service Agreement No. 23 between NEP and its affiliate The Narragansett Electric Company ("Narragansett") under NEP's FERC Electric Tariff, First Revised Volume No. 1 ("Tariff No. 1").

The only substantive change that NEP proposes to Service Agreement No. 23 is the addition of new fixed asset values to be used in calculating amounts that NEP will reimburse to Narragansett, under the existing formula rate set forth in Tariff No. 1, for use of jurisdictional transmission facilities. The new fixed asset values reflect the cost of a bidirectional submarine electric cable and related facilities that Narragansett will construct to implement the transmission component of the Town of New Shoreham project, a public policy project authorized and directed by Rhode Island state law.

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

NEP requests that the Commission accept Sixth Revised Service Agreement No. 23 effective 61 days after the date of this filing, *i.e.*, September 23, 2014.

I. Background

A. Service Agreement No. 23 Between NEP and Narragansett

NEP and Narragansett are wholly-owned subsidiaries of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a Participating Transmission Owner ("PTO") under the terms of the Transmission Operating Agreement ("TOA") by and among the New England PTOs and ISO New England Inc. ("ISO-NE"). All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of the ISO-NE Open Access Transmission Tariff set forth in Section II of ISO-NE's Transmission, Markets and Services Tariff ("ISO-NE Tariff").

Narragansett is a public utility primarily in the business of providing electric and gas distribution service in the State of Rhode Island. Pursuant to state law, Narragansett owns all National Grid transmission facilities located in Rhode Island. Pursuant to Schedule III-B of Tariff No. 1, NEP operates and controls the transmission facilities of itself and its distribution affiliates, including Narragansett, on an integrated basis. Schedule III-B of Tariff No. 1 includes a formula rate under which NEP reimburses Narragansett for NEP's use of Narragansett's facilities to provide jurisdictional transmission service. The formula rate includes the use of fixed asset values that represent the gross plant investment used by NEP to provide the jurisdictional transmission service. The fixed asset values are set forth in Service Agreement No. 23, which implements the Tariff No. 1 arrangements between NEP and Narragansett.[3]

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[3] See NEP filing of revisions to Tariff No. 1 and related service agreements, Vol. 1, Direct Testimony of Karen F. Denehy, at 8-9, 11, Docket No. ER10-523-000 (Dec. 30, 2009). The currently effective version of Service Agreement No. 23 was filed and accepted in that proceeding. *See New England Power Co.*, 136 ¶ 61,024 (2011).

B. The Town of New Shoreham Project

The Town of New Shoreham project is a public policy project authorized and directed by a Rhode Island statute of the same name.[4] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[5]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[6]

Narragansett has agreed to construct, own, and operate the transmission cable and related facilities, including a substation to be built on Block Island. The cable will be bidirectional, in order to allow power to flow either from the Deepwater Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed.

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4 Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

5 *Id.*, § 39-26.1-7(a).

6 *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

C. Related Submittals to the Commission

In addition to the instant filing, NEP will separately file a two-party Large Generator Interconnection Agreement between NEP and Deepwater Wind, in order to interconnect the Deepwater Wind project to NEP's transmission system.

For the same reason, NEP will also: (1) terminate its current Network Integration Transmission Service Agreement No. 108 with Narragansett and replace it with the current form of service agreement under Schedule 21to Section II of the ISO-NE Tariff known as the Local Service Agreement ("LSA") with Narragansett, including ISO-NE as a party (Original Service Agreement No. TSA-NEP-86); and (2) execute a new LSA among NEP, BIPCO, and ISO-NE (Original Service Agreement No. TSA-NEP-83). Whether these service agreements are reported in Electric Quarterly Reports (EQRs) or separately filed with the Commission will depend on whether the agreements fully conform with the *pro forma* LSA under Schedule 21 (common provisions) to Section II of the ISO-NE Tariff.

II. Changes Included in Sixth Revised Service Agreement No. 23

NEP proposes to revise Service Agreement No. 23 to include fixed asset values which reflect the cost of the bidirectional submarine cable, substation on Block Island and related facilities to be constructed by Narragansett to implement the transmission component of the Town of New Shoreham project. As explained above, this cost represents the gross plant investment for NEP's use of Narragansett's facilities to provide jurisdictional transmission service, which is used in the formula rate set forth in Schedule III-B of Tariff No. 1. The gross plant investment value for the submarine cable, substation facilities on Block Island, and related facilities, designated as the Block Island Transmission System or "BITS," is described in Attachment X to Service Agreement No. 23. The final value for BITS will be determined once the project has been completed. The final gross plant value will be reported to the Commission in an informational filing. In addition, the fixed asset value for certain distribution facilities that will be serving a wholesale function once BITS is energized are also quantified in Service Agreement No. 23 for rate purposes. Cost support for the fixed asset value of these facilities is provided in Attachments X and X-1 to Service Agreement No. 23. In accordance with Commission regulations, the calculation of revenue requirements for these facilities under the Tariff No. 1 formula rate will not begin until the date that BITS has gone into commercial service.

NEP also proposes to make ministerial revisions to two sections of Service Agreement No. 23 to update references to the ISO-NE Tariff.[7]

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[7] For ease of reference, NEP notes that, although Service Agreement No. 23 is well over 100 pages in length, all of the revisions proposed in this filing appear in the first few pages of Service Agreement No. 23.

III. Effective Date

NEP requests that the Commission accept Sixth Revised Service Agreement No. 23 effective 61 days after the date of this filing, *i.e.*, September 23, 2014.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Sixth Revised Service Agreement No. 23 in clean format
Attachment B	Sixth Revised Service Agreement No. 23 in black-lined format

V. Communications

Communications and correspondence regarding this filing should be addressed to the following individuals:

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VI. Service

Copies of this filing have been served on Narragansett and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, NEP requests that the Commission accept Sixth Revised Service Agreement No. 23 effective September 23, 2014. Please contact the undersigned with any questions concerning this filing.

Respectfully submitted,

__/s/ Kenneth G. Jaffe__

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Attorneys for National Grid USA

Attachment A

New England Power Company
Sixth Revised Service Agreement No. 23
with The Narragansett Electric Company

SERVICE AGREEMENT
Between
NEW ENGLAND POWER COMPANY
And
THE NARRAGANSETT ELECTRIC COMPANY

Tariff Submitter: New England Power Company
FERC Tariff Program: FERC FPA Electric Tariff
Tariff Title: Tariffs, Rate Schedules, Agreements
Tariff Record Title: New England Power Co. Service Agmt. No. 23
Option Code A
Issued by: William H. Malee Proposed Effective Date: September 23, 2014
Director, Transmission Commercial Services
Issued on: July 24, 2014

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

Dated: February 15, 1974

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

and

THE NARRAGANSETT ELECTRIC COMPANY
A Rhode Island corporation (the "Customer")

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

Schedule I - General Terms and Conditions

Schedule II - Rate Provisions

Schedule III - Terms and Conditions Governing Service

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

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

NONE

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

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By: ______________________________

THE NARRAGANSETT ELECTRIC COMPANY

By: ______________________________

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:	The Narragansett Electric Company
2. Name of District:	Capital and Coastal
3. Service Under:	Schedules III-B of the Tariff and Settlements accepted by the Commission in Docket Nos. ER97-680-000 and ER97-2800-000
4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Massachusetts Electric Company
5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Not Applicable. Narragansett Electric no longer takes generation service under Tariff No. 1. Contract Termination Charge provided pursuant to Contract Termination Charge Amendment.
6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)	Not applicable
7. Entitlements:	
A. On Customer System (Schedule III -C Paragraph C.2.(a))	None
B. Off Customer System (Schedule III-C Paragraph C.2.(b))	None
8. Customer Generation excluded from Firm Capacity Calculation: (Schedule III-C - Paragraph C.3.c.)	None
9. Firm Capacity: (Schedule III-C - Paragraph C.3.c.)	None

10. Integrated Generating, Transmission and Facilities Credits: (Schedule III-B - Paragraph B.4.b) — See Integrated Facilities Amendment

Payable by Company:

Customer Distribution Plant Assets Serving Wholesale Transmission Function (See Attachments X and X-1) :	$390,880
Block Island Transmission System (BITS) Assets Serving Wholesale Transmission Function (See Attachment X):	TBD upon completion
Customer Shared Substation Assets:	None
Customer Buildings and Facilities	None

Formula Rate Inputs:

1. Customer Post Retirement Benefits Other Than Pensions (PBOP) - ($9,000,000)

2. Customer Depreciation Rates

Transmission Accounts	**Rate**
352	1.41%
353	1.90%
354	0.00%
355	2.60%
356	2.29%
357	2.15%
358	2.47%
359	1.15%

Distribution Accounts	**Rate**
361	2.27%
362	1.97%
364	3.58%
365	3.20%
366	1.88%
367.1	3.43%
368	
368.1	3.78%
368.2	4.01%
368.3	4.05%

369	
369.1	3.44%
369.2	0.00%
369.21	0.00%
369.22	3.20%
370	
370.1	5.19%
370.2	5.29%
370.3	5.26%
370.35	4.90%
371	3.68%
373	
373.1	5.64%
373.2	5.65%

General Accounts	**Rate**
390	2.24%
391	1.37%
392	0.00%
393	2.67%
394	4.97%
395	4.26%
396	0.00%
397	6.67%
397.1	4.66%
398	2.87%

11. Primary Service for Resale: None. LNS transmission service is provided by New England Power Company under ISO-NE's Transmission, Markets and Services Tariff (Schedule 21-NEP). Contract Termination Charge provided pursuant to Contract Termination Charge Amendment. Nothing contained herein is intended to modify or otherwise affect the settlements accepted by the Commission in Docket Nos. ER97-680-000 and ER97-2800-000. In the event of a conflict between the Contract Termination Charge Amendment and the settlements, the settlements shall govern.

12. Minimum Demand KW: None

13. Minimum Term:	None
14. Transmission Service for Partial Requirements Customers:	LNS transmission service is provided by New England Power Company (NEP) to The Narragansett Electric Company under ISO-NE's Transmission, Markets and Services Tariff (Schedule 21-NEP.)

Attachment X

Customer Distribution Facilities and Block Island Transmission System Facilities Utilized by Company for Providing Transmission Service

1. Description of Distribution Facilities Serving Wholesale Transmission Function

The existing 34.5 kV mainland distribution facilities serving Block Island include:

- Wakefield 34.5kV Switchyard
- West Kingston 34.5kV Switchyard

A calculation of the plant value of these facilities as allocated for BIPCo service is attached as Exhibit X-1.

2. Description of Block Island Transmission System (BITS) Assets Serving Wholesale Transmission Function

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 22 miles of 34.5 kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5 kV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5 kV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately 0.86 miles of combined overhead and underground infrastructure on Block Island; and
- Approximately 2 miles of combined overhead and underground infrastructure on the mainland in the Town of Narragansett.

Attachment X-1

Calculation of shared value of 34.5kV distribution facilities in southern Rhode Island

LOAD (MW)	2013
Bonnet	8.8
Peacedale	21.5
Wakefield	27.7
URI	12.0
TOTAL TNECO (MW)	70.0
BIPCo	3.6
TOTAL LOAD (MW)	73.6

Component of Cost	(1) Gross Plant Value ($000)	(2) BIPCO Load Percentage	(3) BIPCO Share of Cost ($000)
Wakefield 34.5	$4,156	9%	$373.09
West Kingston 34.5	$364	5%	$17.78
		Total	$390.88

(1) From The Narragansett Electric Company's Plant Accounting Records
(2) BIPCO load divided by the cumulative load from Bonnet back to West Kingston along the 3307/3308 Path:
At Wakefield 3.6/(3.6+8.8+27.7),
At West Kingston 3.6/73.6
(3) = (1) * (2)

NEW ENGLAND POWER COMPANY

Primary Service for Resale

AMENDMENT TO SERVICE AGREEMENT

Dated as of: December 1, 2001

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

and

THE NARRAGANSETT ELECTRIC COMPANY,
a Rhode Island corporation (the "Customer"),

WHEREAS, the Customer is currently an electric customer of the Company under the Company's FERC Electric Tariff, Original Volume No. 1 (the "Tariff") and a Service Agreement as amended (the "Service Agreement"); and

WHEREAS, the Service Agreement was most recently amended by an Amendment to Service Agreement dated as of February 1, 1997 (the "1997 Amendment"); and

WHEREAS, pursuant to the Service Agreement, as amended by the 1997 Amendment, the Company provides to the Customer certain wholesale electric service, described in the 1997 Amendment as "Standard Offer Service"; and

WHEREAS, the Customer has decided to procure all of its requirements for wholesale Standard Offer Service from other suppliers, commencing on December 1, 2001 and the Company has agreed to cease its supply of Standard Offer Service as of that date; and

WHEREAS, the Customer desires to continue to receive from the Company all of the other services specified in the Service Agreement and the Company is willing to continue to supply such services to the Customer in accordance with the Service Agreement; and

WHEREAS, the Company and the Customer desire to modify the Service Agreement to reflect the termination of the supply by the Company and the purchase by the Customer of Standard Offer Service;

NOW, THEREFORE, the Company and the Customer, in consideration of their mutual commitments set forth herein, agree as follows:

1. The Company and the Customer agree that the first sentence of Section 9 of the 1997 Amendment is amended to read as follows:

> 9. For the period commencing on the Contract Termination Date and extending through November 30, 2001 (the "Standard Offer Period"), the Company shall provide service to the Customer in accordance with this section, such service being referred to as "Standard Offer Service."

2. The provisions of this Amendment to Service Agreement shall override any inconsistent provisions of the Service Agreement, including the 1997 Amendment, and, with respect to the Customer, all inconsistent provisions of the Tariff, but all provisions of the Tariff and the Service Agreement, including the 1997 Amendment, that are not inconsistent with this Amendment to Service Agreement shall remain in full force and.

3. This Amendment to Service Agreement shall take effect as of the date it is permitted to become effective by the Federal Energy Regulatory Commission.

4. The rights conferred and obligations imposed on the Customer and the Company under this Amendment to Service Agreement shall be binding on or inure to the benefit of their successors in interest or assignees as if such successor or assignee was itself a signatory hereto.

IN WITNESS WHEREOF, the parties have executed this Amendment of Service Agreement as of the date first written above.

NEW ENGLAND POWER COMPANY

By: Peter S. Flynn

Its: President

THE NARRAGANSETT ELECTRIC COMPANY

By: Cheryl A. LaFleur

Its: President

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Company	)))	Dkt. ER97-680-000

STIPULATION AND AGREEMENT

ARTICLE 1.0
BACKGROUND

1.1 Parties.

This Stipulation and Agreement ("Agreement") is entered into by and among the Rhode Island Public Utilities Commission ("Rhode Island Commission"), the Rhode Island Division of Public Utilities and Carriers ("Rhode Island Division"), The Narragansett Electric Company ("Narragansett"), and New England Power Company ("NEP"). The foregoing entities are referred to as the Signatories.[1]

NEP is now obligated to sell electric energy at wholesale to meet the service area requirements of both affiliated and unaffiliated customers pursuant to its Primary Service for Resale Tariff, NEP's FERC Electric Tariff, Original Volume No. 1 (Tariff 1). Narragansett is NEP's affiliate and is a customer under Tariff 1. The Rhode Island Commission and Rhode Island Division are authorized to represent the interests of Narragansett's retail customers in proceedings before the Federal Energy Regulatory Commission ("Commission") regarding the rates and terms of Tariff 1. (See e.g., R.I. G.L. §§ 39-1-1(3)(c); 39-1-27.1(b); and 39-1-29).

[1] The Utility Workers Union of America, AFL-CIO, and Local 464, Utility Workers Union of America, AFL-CIO, while not parties to the Agreement, do not oppose the Settlement. These parties have otherwise worked out their differences with the Companies.

1.2 Introduction.

This Agreement is designed to implement a comprehensive resolution of the issues presented by the restructuring of the contract relationship between NEP and Narragansett in the context of the Rhode Island Utility Restructuring Act of 1996. (Rhode Island URA).

Under Tariff 1, NEP is obligated to sell to Narragansett, and Narragansett is obligated to purchase from NEP, the requirements of its retail service territory, and they may only terminate those mutual obligations upon seven years' notice. The parties to this Agreement desire to terminate those obligations earlier, in order that Narragansett may accommodate the program of retail choice set forth in the Rhode Island URA.

The Rhode Island URA would extend wholesale competition in power supply markets to retail customers through the provision of retail access directly to Narragansett's customers. Termination of Tariff 1 and the provision of unbundled transmission service by NEP to Narragansett under NEP's open access tariff are both necessary to implement retail access in a manner consistent with that statute.

This Agreement, all provisions of which are interdependent, except where expressly stated otherwise, is intended upon its acceptance by the Commission to provide a final and binding resolution of all issues associated with the liquidation of the mutual sale and purchase obligations under Tariff 1 and Narragansett's Service Agreement with NEP.

ARTICLE 2.0
AMENDMENT OF SERVICE AGREEMENT AND WHOLESALE RATE FREEZE

2.1 Amendment of Service Agreement.

The Service Agreement between NEP and Narragansett shall be amended in accordance with the Amendment to the Service Agreement included in Attachment 1 ("Amendment"). The Signatories agree that the Amendment sets forth rates and other terms for the termination of the reciprocal sale and purchase rights and obligations of NEP and Narragansett, including, without limitation, provisions for the payment and collection of Contract Termination Charges, that are just, reasonable and in the public interest.

2.2 Narragansett is now served by NEP under NEP's wholesale rate W-95(S) approved by the Commission in Docket ER95-267-000. As set forth in the Amendment, the W-95(S) base rates shall remain in effect for NEP's service to Narragansett through the Contract Termination Date defined in Section 3.1.2 below. Nothing in this Agreement or the Amendment shall preclude NEP from petitioning the Commission for a waiver of the Commission's fuel clause regulations (18 C.F.R. § 35.14) or modification of NEP's fuel clause.

ARTICLE 3.0
CONTRACT TERMINATION

3.1 Termination of Purchase and Supply Obligations.

NEP's obligations to provide requirements service to Narragansett and Narragansett's obligations to purchase requirements service shall cease on the Contract Termination Date as defined in Section 3.1.2. Prior to the Contract Termination Date, Narragansett shall not be obligated to purchase, and NEP shall not be obligated to supply, electricity required by any distribution service customer of Narragansett, or its successor or assign, that is taking retail access in accordance with the Retail Access Schedule set forth in Section 3.1.1.

3.1.1 Retail Access Schedule.

Phase 1: On July 1, 1997, the following customers shall have retail access: (i) all new commercial and industrial customers, including new manufacturing customers, commencing service on or after July 1, 1997, with an anticipated average annual demand of two hundred (200) kilowatts or greater; (ii) all existing manufacturing customers with an average annual demand of fifteen hundred (1500) kilowatts or greater; and (iii) all accounts in the name of the State of Rhode Island, provided, however, Narragansett may limit retail access to no more than ten percent (10%) of its total kilowatt-hour sales.

Phase 2: On January 1, 1998, retail access shall be extended to the following customers: all existing manufacturing customers with an average annual demand of two hundred (200) kilowatts or greater and all accounts in the name of the cities and towns in Rhode Island, provided, however, Narragansett may limit retail access to no more than twenty percent (20%) of its total kilowatt-hour sales.

Phase 3: The remaining customers shall have retail access on the earlier to occur of (i) the Retail Access Date defined in § 3.1.2(a) below, (ii) within three months after retail access is available to forty percent (40%) or more of the kilowatt-hour sales in New England including the total kilowatt-hour sales in Rhode Island, or (iii) July 1, 1998, provided, however, if the Rhode Island Commission extends the deadline beyond July 1, 1998, then the remaining customers shall have access on the extended date established by the Rhode Island Commission.

3.1.2 Contract Termination Date Defined.

The Contract Termination Date shall occur on the earlier of the Retail Access Date or the Wholesale Access Date, defined as follows:

3.1.2(a) The Retail Access Date shall be the later of January 1, 1998 or the date of a final, nonappealable order of the Rhode Island Commission approving the divestiture plan for the disposition of NEP's non-nuclear generating facilities.

3.1.2(b) The Wholesale Access Date shall be the earlier of the Retail Access Date or the date on which Narragansett in its sole discretion decides to terminate purchases under Tariff 1 and its Service Agreement with NEP by providing the Commission and the Signatories with 90 days advance notice in writing, said date not to be earlier than January 1, 1998.

3.2 Contract Termination Charges Commencing on the Contract Termination Date.

Narragansett shall pay NEP the Contract Termination Charges pursuant to the terms of the Amendment included in Attachment 1 to this Agreement. If this Agreement is approved by the Commission, the Amendment shall be deemed to be a just and reasonable rate for wholesale electric service pursuant to the Federal Power Act and the Commission's regulations. The Contract Termination Charges under the Amendment shall apply to all kilowatthours delivered by Narragansett or its successors or assigns in Narragansett's Service Area, except that, prior to the Contract Termination Date, the Contract Termination Charges shall apply only to kilowatthours delivered but not sold by Narragansett or its successors or assigns in Narragansett's Service Area. Narragansett's Service Area is defined to include the area served by Narragansett on August 6, 1996. Kilowatthours delivered are defined to include all kilowatthours delivered to electricity consumers in Narragansett's Service Area, whether or not they are present customers of

Narragansett. The Base Contract Termination Charges shall equal the cents per kilowatthour amounts shown on Schedule 1 of the Amendment.

The Base Contract Termination Charges shall recover Narragansett's proportionate share of NEP's total contract termination costs shown in Schedule 1 to the Amendment, which share equals 22.4 percent of the total. The Base Contract Termination Charges shall be subject to adjustments for a Residual Value Credit described in Section 3.3, and a Reconciliation Account described in Section 3.4.

3.3 Residual Value Credit.

As set forth under Section 6.1 below, NEP and its affiliates have agreed to a divestiture of the generation business within six months after the later of (1) the Retail Access Date as defined in NEP's settlement with Massachusetts Electric Company in Docket ER97-678-000, or (2) the receipt of all governmental approvals necessary for such divestiture. Within three months after the sale of any or all of NEP's generating facilities or any other property subject to divestiture, NEP shall implement a residual value credit as a direct offset to the Base Contract Termination Charges authorized under this Agreement. The residual value credit shall be calculated as set forth in Attachment 1 to this Agreement.

3.4 Reconciliation Account.

The Base Contract Termination Charges shall be adjusted through a Reconciliation Account in which differences, whether positive or negative, between the estimates for costs and revenues included in the Base Contract Termination Charges and actual costs and revenues are added to or subtracted from the Base Contract Termination Charges from NEP to Narragansett. The Reconciliation Account shall be calculated as set forth in Attachment 1 to this Agreement.

3.5 <u>Resolution of Disputes Associated with the Implementation of the Contract Termination Charge</u>.

It is intended that disputes about the calculation of the residual value credit, other than disputes about the method of sale or reasonableness of the proceeds, adjustments to the Contract Termination Charges to Narragansett made by NEP pursuant to sections 3.3 and 3.4, and the calculation of the purchased power cost mitigation incentive are, to the extent possible, to be resolved informally and, accordingly, such disputes may not be submitted to the Commission until a good faith effort to achieve a consensual resolution has first been made by following the procedures prescribed herein, provided, however, nothing shall preclude the Commission from examining any such adjustment including, without limitation, any capital addition made by NEP after December 31, 1995, by opening its own investigation. Within 30 days after it has modified Narragansett's Contract Termination Charges to reflect the residual value credit or a Reconciliation Adjustment, NEP shall submit to the Signatories, and to any person or entity that is to receive, under the Commission's regulations, notice of NEP rate filings affecting Narragansett, including, but not limited to the Rhode Island Commission and Rhode Island Division, an explanation of the adjustment including supporting workpapers. If a recipient desires to challenge any portion of the adjustment, it shall advise NEP in writing identifying the basis for its dispute. NEP shall, within 30 days, respond in writing. If the recipient is not satisfied with NEP's further explanation it shall, within 15 days, notify NEP in writing of any remaining disagreements and may request that NEP convene a conference which is to be held within 30 days of such request. The Signatories are to receive from NEP written notice of, and may participate at, any such conference and are to be provided all written communications relevant to the dispute. At such

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conference the participants are to make a good faith effort to resolve outstanding disputes. If, following exhaustion of the foregoing procedure, a participant still disputes any portion of NEP's adjustment, it may petition the Commission for appropriate relief. A copy of such petition shall be served on the Signatories.

If, either as a result of the informal dispute resolution procedure or of Commission action, it is determined that NEP's calculation of the residual value credit or Reconciliation Account balances for Narragansett's Contract Termination Charges were inappropriate, the credit or charges shall nevertheless remain in effect for the balance of the calendar year but NEP shall adjust the Reconciliation Account for any such overcharge, together with a return equal to that specified in Section 1.1.2 of the Appendix to Attachment 1, and shall reflect that adjustment in Narragansett's Contract Termination Charges effective January 1 of the following calendar year.

3.6 Formula For Contract Termination Charges Not Subject to Change.

The Contract Termination Charges reflected in this Agreement and in the Amendment shall not be subject to change and shall remain in effect until NEP has collected all amounts subject to collection thereunder. Neither the formula as set forth in Appendix 1 and attached Schedules to the Amendment nor the Contract Termination Charges recoverable under this Agreement and the Amendment shall be subject to change through application to the Commission pursuant to the provisions of Section 205 or Section 206 of the Federal Power Act, absent the agreement of NEP or its successors or assigns.

3.7 Provisions from Prior Rate Settlements

3.7.1 In its W-10 Wholesale Rate Settlement, Docket No. ER88-630-000, NEP agreed to pay or reimburse Narragansett for "Planning and Dispatchable Program Costs" that include expenditures for (a) administration, research and development, and program evaluation and monitoring on the integrated New England Electric System, and (b) the program costs associated with dispatchable programs. Effective on the Contract Termination Date, NEP shall cease reimbursing Narragansett for these costs.

3.7.2 In its W-95 Wholesale Rate Settlement, Docket No. ER95-267-000, NEP agreed to reimburse Narragansett for Narragansett's discounts to ultimate customers who agreed to provide notice to Narragansett before changing power supplies (Service Extension Discounts). Under Schedule III-D to Tariff 1, NEP is entitled to repayment for any payments by ultimate customers to buydown the notice period and must consent to any modification of the Service Extension Discount agreements. Effective on the date that Narragansett commences Standard Offer Service to its ultimate customers, NEP shall cease reimbursing Narragansett for Narragansett's Service Extension Discounts to ultimate customers. In addition, NEP waives its right to reimbursement of buydown payments made by Narragansett's ultimate customers, and waives its right to require consent prior to any change by Narragansett to the Service Extension Discount agreements.

3.8 Amendment to Fuel Clause

Effective on the Contract Termination Date, NEP shall amend its fuel clause for remaining Tariff 1 customers as set forth in Attachment 2 to this Agreement to assure that the fuel charges to these customers do not increase as the result of the termination of NEP's all-requirements service to Narragansett under this Agreement.

ARTICLE 4.0
TRANSMISSION

4.1 NEP to Provide Narragansett Network Integration Transmission Service.

In accordance with the Retail Access Schedule, NEP shall provide Narragansett Network Integration Transmission Service under its open access transmission tariffs as filed and allowed to become effective from time to time, and on the terms set forth in the Service Agreement for Network Integration Transmission Service included as Attachment 3 to this Agreement. The Network Integration Transmission Service provided under the Service Agreement shall include transmission service necessary for Narragansett to provide transmission and distribution access to retail customers. The Signatories to this Agreement support the approval by the Commission of Attachment 3 as filed as part of this Agreement. However, with the exception of the commitments in the following paragraph, approval of Attachment 3 without change is not a condition of this Agreement. Rather, with respect to transmission access and pricing, NEP and Narragansett will modify the Transmission Service Agreement in a manner that is necessary to accommodate the Commission's policy.

In addition to the charges for Network Integration Transmission Service, in the event Narragansett is denied the ability to recover in its access charges established for the provision of local distribution service the full amount of the Contract Termination Charges billed to Narragansett, NEP or its successors and assigns shall be entitled to collect the unrecovered balance of the Contract Termination Charges as a surcharge on any rate paid for the transmission in interstate commerce of electric energy to Narragansett or to every consumer located in Narragansett's Service Area that takes delivery of electric energy from the transmission facilities of NEP or the distribution facilities of Narragansett. Approval of this provision is a condition of this Agreement.

4.2 Separation of Transmission and Distribution Facilities.

In Order 888, the Commission set forth a seven factor test for determining whether facilities used to provide access to ultimate customers are subject to the ratemaking jurisdiction of the Commission or state ratemaking authorities. Narragansett has completed such an analysis for the jurisdictional separation of its facilities. The analysis has been filed with the Rhode Island Commission in Docket 2515, and is included as Attachment 4 to this Agreement. Based on that analysis, the Signatories agree that all of Narragansett's facilities meet the Commission's seven factor test for designation as distribution facilities subject to the Rhode Island Commission's jurisdiction with two exceptions. The first exception consists of the Narragansett facilities that are paid for by NEP pursuant to the Integrated Facilities Schedule III-B of Tariff 1. The Signatories agree that those facilities are transmission facilities subject to the Commission's exclusive jurisdiction. The second exception consists of certain facilities that have in the past been classified as distribution plant and that are proposed to be retained by Narragansett as distribution although they could be classified as transmission under the Commission's seven-factor test. The Signatories agree that since these instances of distribution plant that could also be classified as transmission are few in number and have a de minimis impact on the costs of either distribution or transmission service, and because classification of the facilities as transmission would be burdensome to both Narragansett and NEP, their historical classification as distribution plant should be retained. The Signatories to this Agreement therefore support the approval by the Commission of the jurisdictional separation of facilities set forth in Attachment 4. However, approval of the jurisdictional separation of facilities without change is not a condition of this Agreement.

4.3 If, within twelve years from the date of this Agreement, NEP sells or spins off all or part of its transmission business to an entity that is not a regulated public utility or does not become a regulated public utility immediately following the acquisition, then NEP will credit any net proceeds in excess of book value to the Reconciliation Account.

ARTICLE 5.0
TRANSITIONAL SERVICE

5.1 Standard Offer Service.

For the period from the Contract Termination Date through December 31, 2009, NEP shall provide Narragansett with Standard Offer Service.[2] Standard Offer Service shall be provided at the prices shown below, adjusted for the fuel index set forth in Attachment 5 to this Agreement:

Calendar Year	Price per kilowatthour
1998	3.2 cents
1999	3.5 cents
2000	3.8 cents
2001	3.8 cents
2002	4.2 cents
2003	4.7 cents
2004	5.1 cents
2005	5.5 cents
2006	5.9 cents
2007	6.3 cents

[2] NEP and Narragansett shall have the right in their sole discretion to shorten the period of standard offer service to December 31, 2004, if Narragansett no longer has the obligation under the Rhode Island URA to extend standard offer service through 2009.

2008	6.7 cents
2009	7.1 cents

The prices shown above shall be for electricity delivered to the meter of Narragansett's ultimate customers, not including the charges for Narragansett's distribution services or for NEP's Network Integration Transmission Service, but including any and all transmission charges to reach NEP's system that are not recovered in Narragansett's transmission cost adjustment provisions. Standard Offer Service shall be available to Narragansett after the Wholesale Access Date or to Narragansett's ultimate customers after the Retail Access Date. After those dates, Narragansett is free to reduce its purchases under the Standard Offer by pursuing other opportunities in the wholesale market, and Narragansett's ultimate customers may terminate Standard Offer Service at any time to purchase from an alternative supplier in the market. Once Narragansett has reduced its wholesale purchases or the ultimate customer has purchased from an alternative supplier in the market, they may not return to Standard Offer service, provided, however, that Standard Offer Service shall be available to all of Narragansett's residential or C-2 Rate customers who have taken service from an alternative supplier for the first year after the Retail Access Date, if such residential or C-2 Rate customer elects to return to Standard Offer Service within 120 days of taking service from an alternative supplier.

5.2 Narragansett Right to Bid the Standard Offer.

Narragansett shall put the Standard Offer out for bid by alternative suppliers offering them the opportunity to provide Standard Offer Service to Narragansett after the Retail Access Date. Narragansett shall have the ability to defer the bid for standard offer service to coordinate with the standard offer service auction of its affiliate, Massachusetts Electric Company. The terms for the bid shall be as set forth in Attachment 5. NEP shall be free to bid in such auction at prices less than those set forth in Section 5.1, provided, however, that, if suppliers do not bid to supply any part of the Standard Offer, NEP, its successors or assignees shall guarantee to provide the unsubscribed portion of such service to Narragansett at the prices set forth in Section 5.1.

5.3 NEP's Obligation to Install Additional Generation Terminated.

Effective on the Contract Termination Date, NEP shall have no further obligation to meet the electricity demands of Narragansett or its ultimate customers, and nothing in this Agreement shall be deemed to require NEP to make any plan, investment, purchase, or commitment to maintain sufficient generating capacity to provide adequate, continuous, or reliable electricity supplies to Narragansett or its ultimate customers except as required to fulfill NEP's obligation under this Agreement to provide Standard Offer Service or as is expressly set forth in a separate power purchase contract between NEP and Narragansett.

ARTICLE 6.0
DIVESTITURE AND MARKET PRICING OF NEP'S GENERATION

6.1 Divestiture of NEP's Generating Business.

6.1.1 NEP agrees, subject to the receipt of all required governmental approvals, to sell, spin off, or otherwise transfer ownership of its generating business to a nonaffiliated entity or entities, other than properties, assets, and entitlements classified to the transmission function. The parties intend that the properties to be divested shall also include: (1) properties owned by New England Energy Inc. (NEEI), (2) the generating units of Nantucket Electric, to the extent they are not classified to the transmission function, including any proceeds from the sale of emission credits, (3) Narragansett's ownership interest in the Manchester Street Station, and (4) Narragansett's and NEP's contractual entitlements to pipeline capacity for natural gas supply to New England. NEP shall develop and file with the Commission by October 1, 1997, a plan to implement divestiture. This plan shall include in particularized detail the generating business to be divested and all properties, assets, and entitlements to be included in the divestiture. The divestiture shall be completed by six months after the later of the Retail Access Date as defined under the filing in Docket No. ER97-678-000, or the receipt of all governmental approvals necessary for the transfer, and shall be updated with an informational filing 90 days before the date of divestiture. The Commission shall review the plan and shall issue a final order on the method of sale and the reasonableness of the proceeds as part of its plan approval.

6.1.2 As part of the divestiture, NEP will endeavor to sell, lease, assign, or otherwise dispose of its minority shares of nuclear units or entitlements on terms that will assign ongoing operating costs and responsibility to a nonaffiliated third party, but may require NEP to retain the obligation for post-shutdown, decommissioning, and site restoration for these units or entitlements. NEP shall recover these post-shutdown, decommissioning, and site restoration costs from Narragansett through the Contract Termination Charge, and shall credit any net positive value or recover any payments associated with such transaction in the reconciliation account of the Contract Termination Charge or the Residual Value Credit. The Parties agree that this approach is reasonable and NEP is authorized to include it in its divestiture plan. The transfer of nuclear entitlements will be subject to the approval of the Nuclear Regulatory Commission ("NRC") to the extent required by NRC regulations. In the event that NEP is unable to sell, lease, assign, or otherwise dispose of its nuclear units or entitlements, NEP shall include 80 percent of the reasonable going forward costs of operating the units and entitlements, including variable costs and capital additions on a cost of service basis,[3] and 80 percent of the revenues from kilowatthour sales from the units and entitlements, in the reconciliation account. Within six months prior to implementing the Performance Based Rate set forth in the prior sentence, NEP will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $1 million. NEP shall also encourage and support a procedure for maintaining a detailed early shutdown plan at each nuclear unit in which it has an entitlement that can be updated easily and that can form the basis to expedite the preparation of a NRC Post-Shutdown Decommissioning Activities Report ("PSDAR") under 10 C.F.R. 50.82 in the event of early shutdown. NEP's sales, if any, from its nuclear units and entitlements shall only be made in the wholesale market to nonaffiliates, provided that NEP shall retain the right to use its minority shares of the units or entitlements to fulfill its minimum, zero bid obligations under the Standard Offer.

6.1.3 As part of the divestiture, NEP will endeavor to sell, assign or otherwise dispose of its power contracts on terms that will assign ongoing contract payments to a nonaffiliated third party. In that event, changes to the above-market payments to power suppliers and any buyout or buydown costs shall be reflected in the Reconciliation Account. In the event that such contracts cannot be sold, assigned, or otherwise disposed of, the power purchased from those contracts shall be sold and the contract payments and market value associated with the sale shall be reflected in the reconciliation account. Such sales, if any, shall only be made in the wholesale

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[3] In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

market to nonaffiliates, provided, however, that NEP shall retain the right to use the contracts, including that with Hydro Quebec, to fulfill its minimum, zero bid obligations under the Standard Offer. Nothing in this Settlement shall affect the rights of suppliers or NEP under purchased power contracts.

6.1.4 The non-utility Signatories have expressed the goals of attaining a market valuation of utility stranded costs, creating a competitive market for supplying electricity to consumers, and separating generating assets from the transmission system to assure comparability of transmission service. They have expressed a preference for voluntary divestiture of utility generation as a means of achieving these goals. NEP and Narragansett have agreed, as part of this Agreement, voluntarily to undertake such divestiture. In exchange, and as consideration for this voluntary divestiture, the Signatories and the Commission by its approval of this Agreement, agree that NEP's Contract Termination Charges to Narragansett and, in the circumstances described in the second paragraph of section 4.1, to every consumer located in Narragansett's Service Area as set forth in the Amendment for the period contemplated by this Agreement are just and reasonable. Accordingly, and to give effect to the reliance placed by the Signatories on the foregoing, the Commission shall treat the finding that such Contract Termination Charges are just and reasonable as a final determination made after public notice and a full investigation of the merits, and, in any future proceeding brought by any person or party, or by the Commission on its own motion, shall accord such finding the full benefit of policies of repose including, without limitation, the application of the doctrines of res judicata, laches, collateral estoppel, the filed rate doctrine, the prohibition against retroactive ratemaking, and the finality of contracts, it being the express intention of the Signatories to prevent, as a matter of law and policy, the Commission or

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any other authority from: (1) revisiting the issue of the justness and reasonableness of the Contract Termination Charges; (2) reducing, other than as set forth in the Amendment, the amount of the Contract Termination Charges either directly or indirectly; and (3) or otherwise limiting the right of NEP, its successors or assigns, to charge and recover the Contract Termination Charges set forth in this Agreement for any reason prior to their recovery in full as contemplated by this Agreement.

6.2 Market Pricing of NEP's Generation.

To facilitate the divestiture and valuation of NEP's units, the Signatories agree that it is in the public interest for NEP or its successors or assigns to be authorized to price its wholesale electricity sales subject to the Commission's jurisdiction at market prices. The Signatories to this Agreement support the approval by the Commission of market pricing for NEP's or its successors' or assigns' wholesale electricity sales after the Contract Termination Date as part of its approval of this Agreement. However, such approval is not a condition of this Agreement.

6.3 Exempt Wholesale Generator Status.

Effective upon appropriate findings by the three states in which NEP provides wholesale service to affiliate distribution companies, NEP shall be authorized to apply for status as an exempt wholesale generator under Section 32 of the Public Utility Holding Company Act of 1935, and its entitlements in generating units shall become eligible facilities under that statute. The Signatories agree that these designations as an Exempt Wholesale Generator and eligible facilities will meet the statutory and regulatory standards for such designation and are appropriate to increase the number of potential purchasers for the market valuation or NEP's assets. The receipt of Exempt Wholesale Generator Status is not a condition to this Agreement.

6.4 Re-entry into Business.

Nothing in this Agreement shall prevent an affiliate of Narragansett from re-entering the generation business following the completion of divestiture, and nothing in this Agreement shall prevent affiliates of Narragansett from marketing electricity, other energy sources, or energy services to customers within or outside Narragansett's service territory.

6.5 Environmental Commitments at NEP's Facilities.

NEP or its successors in interest shall reduce the emissions of NO_x and SO_2 from its Salem Harbor Units 1, 2, 3, and 4, and its Brayton Point Units 1, 2, 3, and 4 by the amounts and on the schedule and terms set forth in Attachment 6.

ARTICLE 7.0
SUCCESSORS AND ASSIGNS

The rights conferred and obligations imposed on any Signatory by this Agreement shall be binding on or inure to the benefit of its successors in interest or assignees as if such successor or assignee was itself a Signatory hereto.

ARTICLE 8.0
ADDITIONAL PROVISIONS

8.1 This Agreement is the product of settlement negotiations. The content of those negotiations shall be privileged and all offers of settlement shall be without prejudice to the position of any party or participant presenting such offer.

8.2 The Signatories to this Agreement recognize and fully understand that their mutual promises in this Agreement evidence the consideration they have extended to each other in their efforts to settle the issues associated with the termination of the rights and obligations of NEP and Narragansett to each other under Tariff 1, in connection with the introduction of wholesale and retail competition for electricity supplies in Narragansett's service territory. The willingness and ability of NEP and Narragansett to commit to and fulfill any and all of their obligations under this Agreement are predicated and conditioned upon the Commission's approval of NEP's Contract Termination Charges to Narragansett and the commitments by the other Signatories to this Agreement to such recovery.

8.3 Acceptance of this Agreement and the Amendment by the Commission shall not be deemed to restrain the Commission's exercise of its authority to promulgate future orders, regulations or rules which resolve similar matters affecting other parties in different fashion.

8.4 The Commission's approval of this Stipulation and Agreement shall endure so long as is necessary to fulfill this Agreement's objectives. In the event of future regulatory or legislative actions which may render any part of this Agreement ineffective, NEP shall nevertheless be held harmless and made whole for the payments it has agreed to accept as consideration for relinquishing its existing rights under NEP's Tariff 1.

8.5 Except as expressly set forth above, this Agreement is submitted on the condition that it be approved in full by the Commission and on the further condition that if the Commission does not approve the Agreement in its entirety, the Agreement shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

Respectfully submitted,

Name: Edward Berlin
Title: Counsel for New England Power Company and The Narragansett Electric Company
Address: Swidler & Berlin, Chtd
3000 K Street, N.W.
Washington, D.C. 20007

Dated: May 30, 1997

New England Power Company
Settlement Agreement

FERC Dkt. ER97-680-000

Harvey L Reiter

Name: Harvey L. Reiter
Title: Counsel for the Public Utilities Commission of the State of Rhode Island and Providence Plantations
Address: 1750 Pennsylvania Ave., N.W. Washington, DC 20006

Dated: May 30, 1997

Name: Alan Shoer
Title: Special Assistant Attorney General
Address: 150 South Main Street
Providence, Rhode Island 02903

on behalf of

Rhode Island Division of Public
Utilities and Carriers

Dated: May 29, 1997

NEW ENGLAND POWER COMPANY

Primary Service for Resale

AMENDMENT TO SERVICE AGREEMENT

Dated as of: February 1, 1997

Parties: NEW ENGLAND POWER COMPANY,
a Massachusetts corporation (the "Company" or "NEP")

and

THE NARRAGANSETT ELECTRIC COMPANY
a Rhode Island corporation (the "Customer" or "Narragansett"),

WHEREAS, the Customer is currently an all-requirements electric customer of the Company under the Company's FERC Tariff, Original Volume No. 1 (the "Tariff"), and a Service Agreement as amended (the "Service Agreement"); and

WHEREAS, under the Service Agreement, the Customer purchases from the Company for resale all of the electric requirements of the ultimate customers in the Customer's service territory; and

WHEREAS, the Rhode Island General Assembly passed into law the Rhode Island Utility Restructuring Act of 1996 ("URA"), which extends wholesale competition in power supply markets to retail customers through the provision of retail access directly to Narragansett's customers; and

WHEREAS, the termination of all-requirements service under the Tariff and the provision of unbundled transmission service by the Company to Narragansett under the Company's open access tariff are necessary to implement retail access in a manner consistent with the URA; and

WHEREAS, the Customer desires to comply with the URA to terminate the requirement that it purchase all of the electric requirements of the customers in its service territory from the Company under the Tariff before the term of the Service Agreement has expired, and to retain the flexibility to terminate its purchase requirement entirely on the date when standard offer service is made available to all distribution customers of Rhode Island electric utilities pursuant to the terms of the URA; and

WHEREAS, the Customer desires to continue to receive transmission service over the transmission facilities owned or operated by the Company after the termination of its purchases under the Tariff; and

WHEREAS, the Customer desires to retain the option, but not the obligation, to purchase electricity from the Company after the termination of its purchases under the Tariff or the option for the ultimate customers in the Customer's service territory to do so; and

WHEREAS, the Company is willing to permit the Customer to terminate its purchase requirement before the Term has expired and to provide the options desired by the Customer, but only upon the terms and conditions set forth in this Amendment to Service Agreement ("Amendment");

NOW, THEREFORE, the Company and the Customer, in consideration of their mutual commitments set forth herein, agree as follows:

1. The Parties agree that, notwithstanding anything to the contrary in the Service Agreement or in the Tariff, the Customer's obligation to purchase electricity under the Service Agreement and the Company's obligation to provide electricity under the Service Agreement shall be reduced as of July 1, 1997, in accordance with the Retail Access Schedule (as defined in

Section 2 of this Amendment), and shall terminate as of the Contract Termination Date, which shall be determined pursuant to Section 3 of this Amendment. Except as provided in Section 9 below, or in a separate contract for power supply, the Company shall have no further obligation to meet the electricity demands of the ultimate customers in the service territory of the Customer on or after the Contract Termination Date, or to make any plan, investment, purchase, or commitment to maintain sufficient generating capacity to provide adequate, continuous, or reliable electricity supplies to the Customer or its ultimate customers on or after such date.

2. The Customer shall not be obligated to purchase, and the Company shall not be obligated to supply, electricity required by any distribution service customer of the Customer, or its successor or assign, that is taking retail access in accordance with the following schedule ("Retail Access Schedule"):

Phase 1: On July 1, 1997, the following customers shall have retail access: (i) all new commercial and industrial customers, including new manufacturing customers, commencing service on or after July 1, 1997, with an anticipated average annual demand of two hundred (200) kilowatts or greater; (ii) all existing manufacturing customers with an average annual demand of fifteen hundred (1500) kilowatts or greater; and (iii) all accounts in the name of the State of Rhode Island, provided, however, the Customer may limit retail access to no more than ten percent (10%) of its total kilowatt-hour sales.

Phase 2: On January 1, 1998, retail access shall be extended to the following customers: all existing manufacturing customers with an average annual demand of two hundred (200) kilowatts or greater and all accounts in the name of the cities and towns in

Rhode Island, provided, however, the Customer may limit retail access to no more than twenty percent (20%) of its total kilowatt-hour sales

Phase 3: The remaining customers shall have retail access on the earlier to occur of (i) the Retail Access Date defined in Section 3, below, (ii) within three months after retail access is available to forty percent (40%) or more of the kilowatt-hour sales in New England including the total kilowatt-hour sales in Rhode Island, or (iii) July 1, 1998, provided, however, if the Rhode Island Public Utilities Commission ("Rhode Island Commission") extends the deadline beyond July 1, 1998, then the remaining customers shall have access on the extended date established by the Rhode Island Commission.

3. The Contract Termination Date shall occur on the earlier of the Retail Access Date, determined in accordance with subparagraph (a) or the Wholesale Access Date, determined in accordance with subparagraph (b).

(a) The Retail Access Date shall be the later of January 1, 1998, or the date of a final nonappealable order of the Rhode Island Commission approving the divestiture plan for the disposition of the Company's non-nuclear generating facilities, provided, however, that in any event, the Retail Access Date shall occur no later than three months after retail access is available to forty percent (40%) or more of the kilowatthour sales in New England, including the total kilowatthour sales in Rhode Island.

(b) The Wholesale Access Date shall be the earlier of the Retail Access Date or the date on which the Customer in its sole discretion decides to terminate purchases under Tariff 1 and the Service Agreement, provided that such date shall not be earlier than January 1, 1998, and provided further that the Customer shall give the Company at least 90 days advance written notice of its declaration of the Wholesale Access Date.

4. The Customer shall pay to the Company the Contract Termination Charges determined in accordance with Appendix 1 and the Schedules attached to this Amendment, which set forth Base Contract Termination Charges and formulae for the adjustment of the Base Contract Termination Charges. Between July 1, 1997 and the Contract Termination Date, the Contract Termination Charges shall apply to all kilowatthours delivered but not sold by the Customer, or its successor or assign, in the Customer's Service Area. After the Contract Termination Date, the Contract Termination Charges shall apply to all kilowatthours delivered by the Customer, or its successor or assign in the Customer's Service Area, whether or not such kilowatthours are sold by the Customer. The Customer's Service Area is defined to include the area served by the Customer on August 6, 1996. Kilowatthours delivered are defined to include all kilowatthours delivered to electricity consumers in the Customer's Service Area, whether or not they are present customers of the Customer.

5. For the period between July 1, 1997 and the Contract Termination Date, the Company shall charge and the Customer shall pay the Demand and Energy Charges shown on Fifty-third Revised Page No. 1 of Schedule II-A, which sets forth the W-95(S) rates, for all kilowatts and kilowatthours purchased by the Customer from the Company for resale to retail customers, and such charges shall not be subject to change during such period for service to the Customer. For the same period, the Company shall charge and the Customer shall pay the

Contract Termination Charges determined in accordance with Appendix 1 and the Schedules attached to this Amendment for all kilowatthours delivered, but not sold, to retail customers in its service territory, pursuant to the Retail Access Schedule. During this period the Company shall reconcile recoveries under W-95(S) rates and the Contract Termination Charge pursuant to procedure set forth in Section 1.1.4 of Appendix 1. After the Contract Termination Date, the Company's service under the W-95(S) rates will cease, and the Company will charge and the Customer will pay the Contract Termination Charges for all kilowatthours delivered to the Customer's Service Area. In addition, the Company shall be obligated to provide the Customer with standard offer service pursuant to Section 9, below.

6. For the period between July 1, 1997 and the Contract Termination Date, the Company will adjust non-fuel billings to the Customer to assure that the Customer's average purchased power expense is not increased solely as a result of the phase-in of retail access in Rhode Island. This adjustment is necessary because of the Company's marginal cost rate design. The sales lost as the result of the Customer's retail load beginning to purchase electricity from other power producers would have been billed by the Company at its lower-cost tail block rates. Thus, a billing adjustment is necessary to prevent the average cost of power supply to the Customer and its remaining retail load from increasing solely as a result of the phase-in of retail access.

Base rate adjustments will be established using estimated and/or actual hourly loads provided to the Company on a monthly basis for Tariff No. 1 billing. The hourly loads will be summed to determine usage during On-Peak Hours and Off-Peak Hours. The Customer will provide the average rate of delivery associated with retail customers in its service territory who purchased electricity from a power producer other than the Company during the sixty-minute clock hour occurring at the time of the Company's peak load for the month. These amounts ("the Retail Access Loads") need to be estimated because the wholesale meter reads at the Company's interconnections with the Customer cannot distinguish between requirements loads under the Company's Tariff No. 1 and Retail Access Loads.

The Company will adjust the Customer's base rate purchased power expense excluding the Retail Access Loads to equal what the base rate purchased power expense would have been if the Retail Access Loads had continued to purchase requirements service from the Customer. Adjustments will be made for demand, on-peak energy and off-peak energy. The total adjustment shall equal the sum of the: (1) Adjustment to Demand Related Expense, (2) Adjustment to On-Peak Energy Expense, and (3) Adjustment to Off-Peak Energy Expense. Formulas for each of these three adjustments are shown below.

$$\begin{array}{l} \text{ADJUSTMENT TO} \\ \text{DEMAND RELATED} \\ \text{EXPENSE} \end{array} = \left(\begin{array}{c} \text{Average Demand} \\ \text{Charge Including} \\ \text{Retail Access Load} \end{array} - \begin{array}{c} \text{Average Demand} \\ \text{Charge Excluding} \\ \text{Retail Access Load} \end{array} \right) \times \begin{array}{c} \text{Total kW} \\ \text{Purchases Excluding} \\ \text{Retail Access Load} \end{array}$$

$$\begin{array}{l} \text{ADJUSTMENT TO} \\ \text{ON-PEAK} \\ \text{ENERGY EXPENSE} \end{array} = \left(\begin{array}{c} \text{Avg Peak Energy} \\ \text{Charge Including} \\ \text{Retail Access Load} \end{array} - \begin{array}{c} \text{Avg Peak Energy} \\ \text{Charge Excluding} \\ \text{Retail Access Load} \end{array} \right) \times \begin{array}{c} \text{Total Peak kWh} \\ \text{Purchases Excluding} \\ \text{Retail Access Load} \end{array}$$

$$\begin{array}{l} \text{ADJUSTMENT TO} \\ \text{OFF-PEAK} \\ \text{ENERGY EXPENSE} \end{array} = \left(\begin{array}{c} \text{Avg Off-Pk Energy} \\ \text{Charge Including} \\ \text{Retail Access Load} \end{array} - \begin{array}{c} \text{Avg OffPk Energy} \\ \text{Charge Excluding} \\ \text{Retail Access Load} \end{array} \right) \times \begin{array}{c} \text{Total Off-Pk kWh} \\ \text{Purchases Excluding} \\ \text{Retail Access Load} \end{array}$$

After the Contract Termination Date, the adjustments pursuant to this paragraph shall cease.

7. Notwithstanding anything to the contrary in the Tariff or the Service Agreement, the Contract Termination Charges specified in Appendix 1 and the attached Schedules to this

Amendment shall remain in effect until the Company has collected all amounts subject to collection thereunder and neither the Customer's obligation to pay the Contract Termination Charges in full nor the formulae for the calculation of the Contract Termination Charges set forth in Appendix 1 and the attached Schedules to this Amendment shall be subject to change through application to the Federal Energy Regulatory Commission pursuant to the provisions of Section 205 or Section 206 of the Federal Power Act, absent the agreement of the Company or its successors or assigns.

8. Notwithstanding anything to the contrary in Schedule III-B of the Tariff, the Company will discontinue fixed credits to the Customer for generation and transmission effective on the date or dates that the Customer's integrated generation or transmission facilities are transferred to the Company, a separate affiliate, or an unaffiliated third party. During any period in which the Customer has transferred some, but less than all of its generation or transmission facilities, the amount of the applicable fixed credit, excluding municipal taxes and cost of removal expenses associated with the South Street Station, will be prorated to reflect the remaining facilities by multiplying the appropriate fixed credit for either generation or transmission by the ratio of gross plant investment remaining to the total gross plant. Nothing in this Amendment shall preclude the Company from otherwise petitioning the FERC to adjust the level of the fixed credits in accordance with the terms of the Tariff.

9. For the period commencing on the Contract Termination Date and extending through December 31, 2009 (the "Standard Offer Period"),[1] the Company shall provide service to

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[1] Company and Customer shall have the right in their sole discretion to shorten the period of standard offer service to December 31, 2004, if Customer no longer has the obligation under the Rhode Island URA to extend standard offer service through 2009.

the Customer in accordance with this section, such service being referred to as "Standard Offer Service."

(a) Standard Offer Service shall be made available at the prices set forth in the Stipulation and Agreement, adjusted for a fuel index. The prices for Standard Offer Service do not include charges for transmission services provided in accordance with section 10 of this Amendment, or charges for distribution services under the Customer's rates for distribution services, but otherwise reflect the price of electricity delivered to the meters of the ultimate customers of the Customer.

(b) Standard Offer Service shall be made available by the Company to the Customer after the Wholesale Access Date for the purposes set forth in paragraph D of Schedule I of the Tariff or to the Customer for resale to those ultimate customers in the Customer's service territory who elect to purchase Standard Offer Service after the Retail Access Date and have not terminated Standard Offer Service to purchase electricity from another supplier, provided that, neither the Customer nor the ultimate customers shall be required to purchase Standard Offer Service from the Company. For the first year after the Retail Access Date, the Company shall make Standard Offer Service available to all residential or Rate C-2 customers of the Customer, who have previously taken service from an alternative supplier, if such residential or Rate C-2 customer elects to return to Standard Offer Service within 120 days of taking service from the alternative supplier.

(c) In the event the Contract Termination Date is determined by the Wholesale Access Date, the Customer shall be free, either in its notice pursuant to section 3(b), or thereafter by giving the Company at least 90 days advance written notice directed to the first day of a calendar month, to terminate or reduce its purchases of Standard Offer Service from the Company in order to obtain electricity from other suppliers in the market. Once the Customer has reduced or terminated its purchases of Standard Offer Service from the Company, the Company shall have no obligation to supply Standard Offer Service to the Customer with respect to the terminated or reduced purchases.

(d) No less than 90 days before the Retail Access Date, the Customer shall notify the Company in writing of the quantity of energy it shall purchase under Standard Offer Service for resale to ultimate customers in its service territory. The Customer shall provide the Company with at least 30 days prior advance written notice, directed to the first day of a calendar month, of reductions in the quantity of energy so purchased due to decisions by customers initially electing Standard Offer Service to purchase electricity from other suppliers after the Retail Access Date. Nothing in this Amendment shall restrict the right of any ultimate customer to purchase electricity from other suppliers after the Retail Access Date, provided that, except as set forth in section 9(b), above, once any such ultimate customer has purchased electricity from another supplier, the Company shall have no obligation to supply Standard Offer Service to the Customer for resale to such ultimate customer.

(e) The Company acknowledges that the Customer will offer alternative power suppliers the opportunity in an auction to supply electricity to enable the Customer to provide Standard Offer Service to ultimate customers in its service territory after the Retail Access Date. The Company shall be free to bid in the auction, provided that the

Company's bid shall not exceed the prices set forth in the Stipulation and Agreement, adjusted for the fuel index set forth in that Agreement.

10. In accordance with the Retail Access Schedule, the Company (including any successor or assign of the Company that succeeds to the Company's obligations with respect to the operation of its transmission facilities) shall, upon request of the Customer, provide network integration transmission service to the Customer in accordance with the Service Agreement for Network Integration Transmission Service between the Customer and the Company included in Attachment 3 to the Stipulation and Agreement, and with the terms and conditions of the tariff maintained in effect by the Company for such service, or in accordance with the policy of the Federal Energy Regulatory Commission as in effect from time to time. Such service shall be provided to the Customer after the Wholesale Access Date to enable the Customer to integrate its loads and resources and shall be provided to the Customer after the Retail Access Date to enable the ultimate customers in the Customer's service territory to integrate their loads and resources. From July 1, 1997 through the Contract Termination Date, the Network Integration Transmission Service shall only apply to kilowatthours delivered, but not sold, by the Customer in the Customer's Service Area, and the Company shall continue to provide transmission service to the Customer pursuant to the W-95(S) wholesale rate for the retail customers continuing to purchase power from the Customer. After the Contract Termination Date, the Network Transmission Service shall apply to all kilowatthours delivered in the Customer's Service Area.

11. This Amendment shall take effect as of the date it is permitted to become effective by the Federal Energy Regulatory Commission, which date shall be referred to as the "Effective

Date." This Amendment, together with all provisions of the Tariff and the Service Agreement necessary to effectuate all provisions of this Amendment, shall remain in effect until all obligations of the parties under this Amendment, including, without limitation, the obligation of the Customer to pay to the Company the Contract Termination Charges, have been discharged in full. Upon the discharge in full of all such obligations, this Amendment and the Service Agreement shall terminate.

12. The provisions of this Amendment shall override any inconsistent provisions of the Service Agreement and, with respect to the Customer, all inconsistent provisions of the Tariff, but all provisions of the Tariff and the Service Agreement that are not inconsistent with this Amendment shall remain in full force and effect.

13. The rights conferred and obligations imposed on the Customer and Company under this Amendment shall be binding on or inure to the benefit of their successors in interest or assignees as if such successor or assignee was itself a signatory hereto.

IN WITNESS WHEREOF, the parties have executed this Amendment of Service Agreement as of the date first written above.

NEW ENGLAND POWER COMPANY

By Jeffrey D. Tranen

Its PRESIDENT

THE NARRAGANSETT ELECTRIC COMPANY

By Robert L. McCabe
Robert L. McCabe

Its President

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CONTRACT TERMINATION CHARGE AMENDMENT

Dated as of: January 1, 2006

1. [Reserved]

2. [Reserved]

3. [Reserved]

4. [Reserved]

5. [Reserved]

6. [Reserved]

7. [Reserved]

8. NEP shall provide a lump sum payment of $10 million to Narragansett to resolve the issues specified in the following paragraph that are associated with the 2000 Reconciliation Report, the 2001 Reconciliation Report, the 2002 Reconciliation Report, the 2003 Reconciliation Report, and the 2004 Reconciliation Report filed by NEP and Montaup Electric Company ("Montaup") (together "Reconciliation Reports"). In addition, NEP shall reflect as a credit to its annual CTC formula, for the period from January 1, 2005 through the end of the fixed recovery period or December 31, 2009 when this pollution control financing credit will expire, the Customer's 22.4 percent share of the actual transmission rate base supported by the pollution control debt actually billed by NEP through its monthly transmission bills times 3.72%, which represents the difference between the actual debt rate reflected in NEP's transmission bills of 7.87% and the settled pollution control debt rate of 4.15%. This prospective commitment is subject to the condition in the NEP's Restructuring Agreement (Appendix 1, Section 1.1.4(e)) that to the extent any of these financing savings are allocated to transmission rates by the Commission, they shall not also be allocated to the CTC.

With the refund of the $10 million and the prospective credit implemented by NEP under the prior paragraph, the Customer accepts as final the resolution of the following specified issues presented by the Reconciliation Reports related to: (i) any transactions and agreements related to NEP's and Montaup's ownership interests in the Millstone III Nuclear Generation Station and NEP's and Montaup's obligations related thereto including the level of proceeds from the settlement of NEP's and Montaup's litigation with Northeast Utilities and its affiliates concerning the operation of the Station, and from the sale of NEP's and Montaup's entitlements in the Station; (ii) the return on the final fuel cores and materials and supplies at any nuclear units in which NEP or Montaup held an ownership interest or entitlement; (iii) the return on Montaup's payments to buy out of the purchased power contract for a portion of the output from the Pilgrim Nuclear Unit; (iv) the credit that NEP reflects in the CTC associated with the pollution control debt in NEP's capital structure and will reflect in the CTC prospectively.

The Customer stipulates that no further adjustments associated with the issues specified in the prior paragraph are warranted, and agrees not to bring any action, claim, or complaint associated with these specified issues, or to seek any adjustment to the reconciliations billed by NEP or Montaup associated with these specified issues before the Federal Energy Regulatory Commission under Section 3.5 of NEP's and Montaup's Restructuring Agreements, any provision of the Commission's regulations, or the Federal Power Act.

NEW ENGLAND POWER COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH
THE NARRAGANSETT ELECTRIC COMPANY UNDER
FERC ELECTRIC TARIFF, ORIGINAL VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT
TERMINATION CHARGES

1.1 The Fixed Component of the Contract Termination Charge shall include Narragansett's 22.4 percent allocated share of NEP's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over the period commencing on the Divestiture Date defined as the date of closing for the sale of NEP's non-nuclear generating facilities pursuant to the Asset Purchase Agreement dated August 5, 1997, and continuing through December 31, 2000 the actual unrecovered balances for plant and regulatory assets as of the Divestiture Date:

(a) Plant balances shall include unrecovered net book value as shown on Schedule 1, Page 4, Column (7), of the following NEP generation-related investments as of the Divestiture Date:[1]

(i) Brayton Point Units 1, 2, 3, 4, including the Brayton Point Diesels; Salem Harbor Units 1, 2, 3, 4; Wyman Unit 4;

(ii) Manchester Street Station, including NEP's reimbursement to Narragansett for its ownership share of the Station at Narragansett's net book value,

[1]The figures shown on Schedule 1, Page 4, Column (7) are estimates assuming that the Retail Access Date and Contract Termination Date occur on January 1, 1998, and that the Divestiture Date occurs on July 1, 1998. The estimates will be updated for actual balances as of the Divestiture Date on the "Reconciliation Date" which shall be no later than 90 days after the actual Divestiture Date. Differences shall be reflected in the revision under Section 1.1.4(a), below. The reconciliations made on the Reconciliation Date shall remain subject to final adjustments or true-ups, if necessary, and any changes shall be reflected in the Reconciliation Account at the time the adjustment or true-up is made.

prepaid property tax payments made in accordance with a tax treaty with the City of Providence, and capital additions past December 31, 1995, but committed prior to that date;

(iii) NEP Hydro Units;
(iv) Bear Swamp Pumped Storage Facility;
(v) NEP's Entitlements in the Vermont Yankee Unit;
(vi) NEP's ownership share of Millstone Unit 3;
(vii) NEP's ownership share of Seabrook Unit 1;
(viii) Step-up transformers at NEP generating units which are excluded from NEP's transmission rates;
(ix) General plant allocated to generation;
(x) Generation-related property held for future use and non-utility property;
(xi) Generation-related investment in the Nantucket Diesels; and
(xii) Generation-related investment in the NEP Diesels at Gloucester and Newburyport.

The plant balances for NEP's entitlements and ownership shares in nuclear units (items v, vi, and vii above) shall also include the balances for the final fuel cores and materials and supplies; and

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 5, Column (2), as of the Divestiture Date[2]:

(i) FAS 109;
(ii) Unamortized losses on Reacquired Debt;
(iii) Unamortized pipeline demand charges deferred prior to the commercial operation of Manchester Street;
(iv) NEEI;
(v) FAS 106 Deferral;
(vi) Unamortized power contract buyout costs;

[2] The figures shown on Schedule 1, Page 5, Column (2) are estimates assuming that the Retail Access Date and the Contract Termination Date occur on January 1, 1998, and that the Divestiture Date occurs on July 1, 1998. The estimates will be updated for actual balances as of the Divestiture Date on the Reconciliation Date and shall be reflected in the revision under Section 1.1.4(a), below. The reconciliations made on the Reconciliation Date shall remain subject to final adjustments or true-ups, if necessary, and any changes shall be reflected in the Reconciliation Account at the time the adjustment or true-up is made.

(vii) Rate clauses;
(viii) South Street Cost of Removal;
(ix) Brayton Point Rotor;
(x) Seabrook tax true-up;
(xi) Decontamination and decommissioning costs;
(xii) W-95 Settlement Adjustment Account to the extent not otherwise recovered; and
(xiii) Unamortized ITC associated with nuclear entitlements.

1.1.2 Revenues sufficient to provide an overall pretax return of 12.56 percent including a return on common equity of 11 percent for the period after the Divestiture Date,[3] multiplied by the average of the beginning and ending balances in each calendar year beginning in the year of the Contract Termination Date of the sum of the following:

(a) Unrecovered net book value of NEP's generation investments as defined under 1.1.1(a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1(b) above, excluding the rate clauses and unamortized ITC associated with nuclear entitlements under 1.1.1(b)(vii) and (xiii), less

(c) Deferred Taxes as shown in Schedule 1, Page 13, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of NEP's generation investment, plus

[3] The difference between the 11.01 percent authorized under the Settlement prior to the Divestiture Date and 12.56 percent return authorized for that same period once Divestiture occurs, shall be recovered through an offset to the Residual Value Credit, and the 12.56 percent return that occurs after the Divestiture Date is included in the attached schedules. The 12.56 percent return shall be used as the return wherever a return is referenced throughout this Appendix. However, the 12.56 percent return after the Divestiture Date shall be adjusted in accordance with Section 1.1.4(e).

(ii) the unrecovered net book value of generation-related regulatory assets, excluding rate clauses, less

(iii) the unrecovered balance of generation investment for tax purposes, less

(iv) the unrecovered balance of generation-related regulatory assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over the period commencing on the Divestiture Date and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition Obligation of NEP and allocated to NEP by its affiliates[4]; and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of NEP and allocated to NEP by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of NEP and allocated to NEP by affiliates. On the Reconciliation Date, these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) On the Reconciliation Date, NEP shall revise the balances in Sections 1.1.1(a) and (b), and the amortization and return for the period between the

[4] Any FAS 106 Transition Obligation of NEP and allocated to NEP by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

Divestiture Date and December 31, 2000 to reflect the actual balances as of the Divestiture Date. The reconciliations made on the Reconciliation Date shall remain subject to final adjustments or true-ups, if necessary, and any changes shall be reflected in the Reconciliation Account at the time the adjustment or true-up is made.

(b) On the Reconciliation Date, NEP shall reconcile the balances as of the Divestiture Date in Sections 1.1.1 and 1.1.3 for Narragansett's 22.4 percent allocated share of (i) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 106 obligation; and (ii) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 87 obligation, but the gains or losses associated with FAS 87 shall be recognized only to the extent that they exceed five percent of the greater of plan assets or liabilities. NEP shall fund the FAS 106 and FAS 87 obligations under this Section and Section 1.2.2(f) as rapidly as permitted by the tax law up to the level of revenues collected for this purpose.[3] Any revenues associated with these obligations that cannot be immediately

[3]The FAS 106 and FAS 87 costs recovered through the Contract Termination Charge shall be reflected as a credit to NEP's transmission rates. NEP's post-divestiture FAS 106 or FAS 87 gains or losses recognized on NEP's books shall be fully reflected in rates to customers and shall neither be retained nor borne by NEP. NEP shall propose an allocation of these post-divestiture gains or losses between customers paying contract termination charges and transmission customers to recognize the higher cash contributions of the customers paying the Contract Termination Charges in the filing implementing the Residual Value Credit.

funded shall be put into a separate account on the books to be reserved with the return specified in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS 106 and FAS 87, whether positive or negative, shall be subtracted from or added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, NEP shall reconcile the balances as of the Divestiture Date for Narragansett's 22.4 percent allocated share of (iii) the FAS 109 regulatory asset; and (iv) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the residual value credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the Divestiture Date and December 31, 2009. The adjustments and reconciliations made on the Reconciliation Date pursuant to this subsection shall remain subject to final adjustments or true-ups, if necessary, and any changes shall be reflected in the Reconciliation Account at the time the adjustment or true-up is made.

(c) Upon the sale of NEEI properties, NEP shall reconcile NEEI recovery to reflect the difference between the actual NEEI loss following the sale and the estimated NEEI loss reflected in the Contract Termination Charge. The reconciliation shall credit to Narragansett, Narragansett's 22.4 percent allocated share of the compounded return that NEP accrued on the NEEI unamortized balance through the Contract Termination Charge prior to the sale of the NEEI properties, and shall account for and reconcile all differences between: (i) actual amortization under NEP's Tariff No. 1 fuel clause as compared to the amortization estimates included in the Contract Termination Charge and Schedule 2; (ii) actual balances on NEEI's books at the sale as compared to balances used to calculate the Base Contract Termination Charge; and (iii) actual net proceeds after transaction costs realized from the sale as compared to those used to estimate market value when calculating the Base Contract Termination Charge. Following the completion of the above reconciliations, Narragansett's 22.4 percent allocated share of the differences in the balances, whether positive or negative, shall be subtracted from or added to the Narragansett 22.4 percent allocated share of the balance for NEEI losses and the Schedule for prospective recovery of NEEI costs shall be adjusted to amortize, with the return specified in Section 1.1.2, the adjusted balance over the period between the sale and December 31, 2009. An exhibit showing the methodology for the NEEI reconciliation is attached as Schedule 3, page 2. If the Contract Termination Date has not yet occurred at the time the NEEI properties are sold, the same schedule of recovery shall be applied to NEP's Tariff No. 1 fuel clause to Narragansett so that NEP fully recovers the revised NEEI recovery from Narragansett.

(d) As of the Divestiture Date, NEP[6] shall implement a Residual Value Credit to Narragansett. The Residual Value Credit, shown on Schedule 6(a), assumes that the conditions in Section 3.4 of the Asset Purchase Agreement have been fully achieved and the additional consideration of $225 million has been paid by the Buyer at closing. The Residual Value Credit shown on Schedule 6(b) assumes that these conditions have not been met and the Buyer has held back $225 million at closing. Schedule 6(b) also includes a revised Schedule 1(b) showing the effect of the $225 million hold-back on the Contract Termination Charge. Both Schedule 6(a) and Schedule 6(b) are based on estimates that will be reconciled on the Reconciliation Date to actual figures as of the Divestiture Date with differences, if any, included in the Reconciliation Account established

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[6] Within three months after the completion of the sale of any other property whose costs have been included in the Contract Termination Charge, NEP shall reflect the net proceeds from the sale as calculated in this section in the Reconciliation Account. NEP shall be authorized to amortize the net proceeds with a return over a period of up to five years if necessary to maintain a stable and declining pattern of Contract Termination Charges. NEP shall be authorized to amortize any Divestiture proceeds previously held-back pursuant to this section in the same manner. Net proceeds, if any, from NEP's future leases of nuclear entitlements will also be flowed through the Reconciliation Account.

under Section 1.2.1. The adjustments and reconciliations made on the Reconciliation Date shall remain subject to final adjustments or true-ups, if necessary, and any changes shall be reflected in the Reconciliation Account at the time the adjustment or true-up is made. The Residual Value Credit is calculated as follows:

(i) Narragansett's 22.4 percent allocated share of Total Proceeds[7] equal to the sale price and other consideration received by NEP excluding $85 million[8] which purchasers have paid into an account for employee benefits pursuant to Section 1.2.2(f), less

(ii) The revenues lost or gained by NEP between July 1, 1997 and the Divestiture Date measured by the difference between the revenues, excluding revenues attributable to items included in the Contract Termination Charge or in NEP's transmission rates, that NEP would have collected under Rate W-95(S) had it continued to make the sales to Narragansett under Tariff 1 and the revenues, excluding

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[7] As part of the terms of the Divestiture, NEP has required the buyer of the facility to pay NEP the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for NEP's non-nuclear facilities are excluded from the plant balances under Section 1.1.1, and are excluded from the calculation of the Residual Value Credit. In addition, the Buyer also purchased from NEP the Company's equity interest in Narragansett Energy Resources Company (NERC). As part of this transaction New England Electric System will contribute the NERC stock to NEP at book value. As a result, the net book value of the stock is subtracted from the proceeds and excluded from the Residual Value Credit.

[8] The $85 million represents total costs of $91 million less $6 million of FAS 106 transition obligation which is being recovered under Section 1.1.3.

transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Narragansett's customers during the period, together with a credit for Narragansett's share of the revenue from sales at no less than market prices made by NEP to third parties during the period, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of kilowatthours delivered by Narragansett during the period between the July 1, 1997 and the Divestiture Date, less

(iii) Narragansett's 22.4 percent allocated share of capital investments demonstrated to be prudently incurred after December 31, 1995, excluded from the plant balances in Section 1.1.1 (a) above,[9] less

(iv) The difference between the overall pretax return of 11.01 percent that NEP realized prior to the Divestiture Date pursuant to Section 1.1.2 and 12.56 percent as applied to Narragansett's 22.4 percent allocated share of the outstanding balances for plant and regulatory assets, net of deferred taxes, listed in Section 1.1.1 over the period from July 1, 1997 to the Divestiture Date, less

[9] NEP's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities in 1996 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. NEP may include additional projects, if any, as of the Divestiture Date in the reconciliation to be made on the Reconciliation Date subject to the dispute resolution procedures under Section 3.5 of the Agreement.

(v) Narragansett's 22.4 percent allocated share of reasonable transaction costs associated with the divestiture including the cost of refinancings, repurchases, and retirements of securities occurring after March 20, 1997, in excess of $20 million to NEP.

As shown in Schedule 1, page 2, the Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts has been credited to the Fixed Component in equal monthly amounts over the period commencing on the Divestiture Date and continuing through December 31, 2000. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Contract Termination Date, or (ii) the Residual Value Credit exceeds the Contract Termination Charge in any given year.

(e) Effective with refinancings, repurchases, and retirements of securities on and after March 20, 1997, NEP shall, on the Reconciliation Date for all purposes associated with the implementation of the Contract Termination Charge or the Residual Value Credit, flow through the Reconciliation Account the annual effects associated with any differences between the 12.56 percent overall pre-tax return and the actual pre-tax return, calculated using an 11 percent return on common equity, attributable to changes in the cost of debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 12.56 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 12.56 percent overall pre-tax return shall be adjusted to include NEP's actual cost of debt and preferred stock using a 11 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

NEP shall not be required to implement securitization unless implementation would produce net savings after taking into account all transaction costs including call provisions and prepayments, if applicable.

Any and all financing savings associated with refinancing following divestiture or securitization shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in NEP's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by the Commission, however, they shall not also be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Narragansett's allocated share of the items specified in Section 1.2.2, below adjusted for the Reconciliation Account discussed in Section 1.2.1.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract Termination Charge Payments by Narragansett and Narragansett's allocated share of the estimated variable costs listed in Section 1.2.2 below and actual Contract Termination Charge payments by Narragansett and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from NEP to Narragansett. The Reconciliation Account shall also include the adjustments under Sections 1.1.2, note 4, and 1.1.4 above, caused by (i) a change in the Divestiture Date, (ii) any other revisions to the Fixed Component associated with the reconciliations, adjustments, or true-ups that are completed on or after the Reconciliation Date, (iii) future sales of property or leases of nuclear entitlements, and (iv) changes in cost of capital. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

The Reconciliation Account shall accumulate each year and shall be used to adjust NEP's Base Contract Termination Charges to Narragansett in the following year. Thus, NEP shall return or collect Narragansett's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Contract Termination

Charges to Narragansett in the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 2.8 cents per kilowatthour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Contract Termination Charge.

1.2.2 Narragansett's 22.4 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1 at page 3. The difference between Narragansett's 22.4 percent allocated share of the actual variable costs incurred by NEP and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) Nuclear Decommissioning and Other Post Shutdown Costs shown on Schedule 1, Pages 6 and 7, shall include: (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration assessed to NEP by the operators of each nuclear electric generating facility specified in Section 1.1.1(a) (v), (vi), and (vii) above, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds; (ii) all other reasonable post shutdown costs associated with NEP's entitlements in the units listed in Section 1.1.1(a), (v), (vi), and (vii) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with

Yankee Rowe, Connecticut Yankee and Maine Yankee shown on Schedule 1, page 7. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to NEP's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, any over collection will be refunded to Narragansett in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

(b) Power Contract Payments will be (i) all payments by NEP for Long-Term Power Supply Contracts less the payments received from the Buyer or from resale of electricity purchased under the contracts into the wholesale market which are shown on Schedule 1, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts, plus (iv) the Power Contract Buyout Incentive realized.

(i) Long-Term Power Supply Contracts will be the power supply contracts listed below which were in place as of December 31, 1995, between NEP and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

(1) Ocean State Power
(2) Canal
(3) NU Slice
(4) Lawrence Hydro
(5) Mascoma Hydro
(6) Pontook Hydro
(7) Northeast Landfill
(8) Turnkey
(9) Ogden Haverhill
(10) RESCO Saugus
(11) RESCO N. Andover
(12) Signal - Millbury
(13) Hydro MWRA
(14) RFA Lawrence
(15) ALTRESCO
(16) Clark University
(17) Milford Power
(18) Pawtucket
(19) Hydro Quebec

(ii) Economic Buyout Payments will be the trigger payments agreed to by NEP under Section 8(d) of the PPA Transfer Agreement, associated with the disposition of the Long-Term Power Supply Contracts. Economic Buyout Payments shall be recovered as incurred to the extent that current recovery does not increase rates to customers above the level that would have been incurred absent the disposition of the Long-Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

(iii) Credit for Unit Sales Contracts will be all unit sales contracts entered into by NEP as of December 31, 1995, for sales from the following generating units if they are not otherwise subject to market valuation, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9). Units Sales Contracts include contracts for NEP's sale of power from the following units:

(1) Maine Yankee
(2) Millstone 3
(3) Seabrook I

(iv) Power Contract Buyout Incentive will be the sum of: (a) the Power Contract Buyout Incentive Associated with Divestiture calculated in accordance with Schedule 3, pages 3 and 4; and (b) the Power Contract Buyout Incentive Independent of Divestiture which shall represent 10% of the savings realized by customers as the result of the sale, assignment, disposition or buy down of its power supply contracts occurring outside of the divestiture process. The Power Contract Buyout Incentive Independent of Divestiture shall be determined at the time of the sale, assignment, disposition or buy down using the market prices shown on page 4 of Schedule 3. The Total Power Contract Buyout Incentive shall not exceed $13.2 million, stated on a present value basis upon the divestiture using a discount rate equal to the actual pre-tax return in place following completion of post divestiture refinancing as determined under Section 1.1.4(e), and the market prices shown on page 4 of Schedule 3, notwithstanding the actual market prices for the power. NEP shall document the level of the Power Contract Buyout Incentive in a report, and the amount of the Power Contract Buyout Incentive shall be subject to the dispute resolution procedures set forth under Section 3.5 of the Settlement Agreement. The Power Contract Buyout Incentive associated with Divestiture will be recovered in equal increments over the period from the divestiture through December 31, 2009, with appropriate adjustments for the time value of money, and the Power Contract Buyout Incentive Independent of Divestiture will be recovered in equal increments over the remaining term of the related purchased power contract, with appropriate adjustments for the time value of money.

(d) (i) Transmission wheeling charges for the units sold to the Buyer or for the contracts set forth in Section 1.2.2(b) to the extent the transmission wheeling charges exceed the charges that would be payable under NEP's proposed pricing policy that is incorporated in the Tariff No. 9 filing and Continuing Site/Interconnection Agreement filed by NEP on October 1, 1997, and (ii) transmission wheeling as shown in Schedule 1, Page 3, associated with the transmission of electricity from NEP's entitlements in Connecticut Yankee, Millstone Unit 3, Wyman Unit 4, and Vermont Yankee, which units are located off of NEP's transmission system, together with support payments to Central Maine Power and Connecticut Light and Power which are necessary for the transmission of NEP's remote generation. These wheeling and support payments shall include only costs that are excluded from recovery under NEP's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of the unit.

(e) Payments in Lieu of Property Taxes will include all reasonable costs incurred by NEP or its affiliates associated with payments in lieu of property taxes to the cities and towns in which NEP owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciling Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining Costs as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by NEP or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of NEP's Tariff No 1, including, but not limited to early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. NEP shall require purchasers of its generating business to pay $85 million for the costs under this paragraph incurred by NEP or its affiliates. In the event that the actual costs incurred under this paragraph are less than $85 million, excluding costs found by the Commission to be recoverable in NEP's transmission rates, NEP shall flow back the difference to customers in the Reconciliation Account. The procedure established in this paragraph shall be the exclusive method for recovering the costs under this paragraph, and, except in the event of legislation changing required benefits, neither NEP nor its affiliates shall be able to recover more than $85 million for these costs. Thus, for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shall include all damages, costs, or recoveries associated with NEP's generating business which accrued prior to the date of divestiture and which were not: (i) included in the reserves for generation related, uninsured claims other than claims associated with Environmental Response Costs as of January 1, 1995, plus annual additions to the reserves for uninsured claims in NEP's W-95(S) rate, less actual payments out of the reserve for generation related claims during the period from January 1, 1995 through the Contract Termination Date; (ii) assigned to NEP's successor in interest; (iii) recovered from NEP's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, Damages, Costs, or Net Recoveries from claims were assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of nuclear units or entitlements that are not otherwise reflected in the Residual Value Credit. If NEP is unable to sell, lease, assign, or otherwise dispose of its nuclear units or entitlements on the terms set forth in the Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and capital additions on a cost of service basis,[10] associated with NEP's nuclear units or entitlements that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units or entitlements that are not otherwise reflected in contract termination charges. The Performance Based Rate shall apply for the period from the Contract Termination Date to the date that NEP either sells, leases, assigns or otherwise disposes of the nuclear unit or entitlement of the nuclear unit is shutdown. Within six months prior to implementing the Performance Based Rate, NEP will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for non-performance of $1 million. Such sales, if any, shall only be made in the wholesale market to non-affiliates, provided, however, that NEP shall retain the right to use its minority shares of the units or entitlements to fulfill its minimum, zero bid

[10] In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by NEP or Narragansett relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by NEP or Narragansett relating to deposits and wastes occurring prior to the

Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located either within the switchyards for which NEP will retain a permanent easement on parcels that are otherwise being divested or the Brayton Point step-up transformers if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental

Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) reserves related to Environmental Response Costs as of January 1, 1995, less actual payments out of the reserve for Environmental Response Costs during the period from January 1, 1995 through the Contract Termination Date; (ii) proceeds from insurance companies related to Environmental Response Costs; (iii) proceeds from the sale of properties purchased under paragraph (iii); and (iv) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of NEP to governmental authorities or third parties other than the buyer or buyers of NEP generating facilities under any environmental law including those referenced in paragraph (iv).

New England Power Company
Summary of Contract Termination Charges
to The Narragansett Electric Company

POST-DIVESTITURE
2004 CTC Reconciliation

Line	Year	Estimated Narragansett Electric Company Gwh Delivered	Portion of the Year for Retail Access	Estimated Narragansett Electric Company Gwh Delivered for Portion of the Year	Share of Fixed Component		Share of Variable Component		Share of Total Termination Charge	***TOTAL CTC EXPENSES*** **Contract Termination Charge**	Less Prepayment & Lump Sum Payment	Adjusted CTC	
					$ in Millions	cents/kwh	$ in Millions	cents/kwh	$ in Millions	**cents/kwh**	$ in Millions	$ in Millions	cents/kwh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
(1)	**1998**	**1,626**	**100%**	**1,626**	**5.4**	**0.33**	**19.0**	**1.17**	**24.4**	**1.50**			
(2)	**1999**	**5,013**	**100%**	**5,013**	**38.8**	**0.77**	**40.5**	**0.81**	**79.2**	**1.58**	**21.4**	**57.8**	**1.15**
(3)	**2000**	**5,165**	**100%**	**5,165**	**9.9**	**0.19**	**49.7**	**0.96**	**59.6**	**1.15**	**17.5**	**42.1**	**0.82**
(4)	**2001**	**5,183**	**100%**	**5,183**	**1.4**	**0.03**	**40.2**	**0.78**	**41.5**	**0.80**	**5.0**	**N/A**	**N/A**
(5)	**2002**	**5,232**	**100%**	**5,232**	**1.3**	**0.02**	**33.8**	**0.65**	**35.1**	**0.67**			
(6)	January	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(7)	February	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(8)	March	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(9)	April	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(10)	May	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(11)	June	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(12)	July	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(13)	August	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(14)	September	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(15)	October	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(16)	November	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(17)	December	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(18)	**2003**	**5,288**	**100%**	**5,288**	**1.2**	**0.02**	**34.9**	**0.66**	**36.1**	**0.68**			
(19)	January	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(20)	February	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(21)	March	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(22)	April	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(23)	May	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(24)	June	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(25)	July	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(26)	August	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(27)	September	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(28)	October	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(29)	November	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(30)	December	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(31)	**2004**	**5,356**	**100%**	**5,356**	**1.1**	**0.02**	**32.5**	**0.61**	**33.7**	**0.63**			
(32)	2005	5,428	100%	5,428	1	0.02	35	0.65	36	**0.67**			
(33)	2006	5,496	100%	5,496	1	0.02	35	0.64	36	**0.66**			
(34)	2007	5,562	100%	5,562	1	0.02	21	0.38	22	**0.40**			
(35)	2008	5,628	100%	5,628	1	0.02	23	0.40	23	**0.42**			
(36)	2009	5,695	100%	5,695	1	0.01	17	0.30	18	**0.31**			
(37)	2010	5,783	100%	5,783			14	0.24	14	**0.24**			
(38)	2011	5,864	100%	5,864			9	0.15	9	**0.15**			
(39)	2012	5,946	100%	5,946			9	0.15	9	**0.15**			
(40)	2013	6,029	100%	6,029			9	0.14	9	**0.14**			
(41)	2014	6,114	100%	6,114			8	0.13	8	**0.13**			
(42)	2015	6,199	100%	6,199			8	0.12	8	**0.12**			
(43)	2016	6,286	100%	6,286			6	0.09	6	**0.09**			
(44)	2017	6,374	100%	6,374			4	0.07	4	**0.07**			
(45)	2018	6,463	100%	6,463			1	0.02	1	**0.02**			
(46)	2019	6,554	100%	6,554			1	0.01	1	**0.01**			
(47)	2020	6,646	100%	6,646			0	0.00	0	**0.00**			
(48)	2021	6,739	100%	6,739			0	0.00	0	**0.00**			
(49)	2022	6,833	100%	6,833			0	0.00	0	**0.00**			
(50)	2023	6,929	100%	6,929			0	0.00	0	**0.00**			
(51)	2024	7,026	100%	7,026			0	0.00	0	**0.00**			
(52)	2025	7,124	100%	7,124			0	0.00	0	**0.00**			
(53)	2026	7,224	100%	7,224			0	0.00	0	**0.00**			
(54)	2027	7,325	100%	7,325			0	0.00	0	**0.00**			
(55)	2028	7,427	100%	7,427			0	0.00	0	**0.00**			
(56)	2029	7,531	100%	7,531			0	0.00	0	**0.00**			

Column Notes:
(1) Annual totals for 1998-2002 Reconciliations, monthly for 2003-2004; annual thereafter.
(2) Per June 3, 1996 Integrated Least Cost Plan Update. Includes incremental DSM.
(3) Per Utility Restructuring Act of 1996, pages 24 and 25. Assumes 100% Retail Access as of 1/1/98.
(4) Column (2) x Column (3).
(5) See Schedule 1, Page 2, Column (7).
(6) Column (5)/Column (4) x 100.
(7) See Schedule 1, Page 3, Column (18).
(8) Column (7)/Column (4) x 100.
(9) Column (5) + Column (7).
(10) Column (9) / Column (4) x 100.
(11) The $5 million payment was paid to Narragansett in December 2000 to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.

New England Power Company
Summary of Contract Termination Charges
The Narragansett Electric Company Share (22.4%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	**1998**	**11.3**	**45.3**		**0.3**	**56.9**	**(51.4)**	**5.4**
(2)	**1999**	**23.9**	**146.6**	**21.4**	**1.2**	**193.1**	**(154.3)**	**38.8**
(3)	**2000**	**11.9**	**151.1**		**1.2**	**164.2**	**(154.3)**	**9.9**
(4)	**2001**	**5.5**	**0.0**		**1.1**	**6.6**	**(5.3)**	**1.4**
(5)	**2002**	**5.0**	**0.0**		**1.1**	**6.1**	**(4.8)**	**1.3**
(6)	January	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(7)	February	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(8)	March	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(9)	April	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(10)	May	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(11)	June	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(12)	July	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(13)	August	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(14)	September	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(15)	October	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(16)	November	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(17)	December	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(18)	**2003**	**4.6**	**0.0**		**1.0**	**5.6**	**(4.4)**	**1.2**
(19)	January	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(20)	February	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(21)	March	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(22)	April	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(23)	May	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(24)	June	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(25)	July	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(26)	August	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(27)	September	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(28)	October	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(29)	November	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(30)	December	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(31)	**2004**	**4.2**	**0.0**		**1.0**	**5.1**	**(4.0)**	**1.1**
(32)	2005	4	0		1	**5**	(4)	**1**
(33)	2006	3	0		1	**4**	(3)	**1**
(34)	2007	3	0		1	**4**	(3)	**1**
(35)	2008	3	0		1	**3**	(2)	**1**
(36)	2009	2	0		1	**3**	(2)	**1**
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
Columns (2) through (5) represent 22.4% of the same Column number on Schedule 1, Page 12.
(7) Column (5) + Column (6).

New England Power Company
Summary of Contract Termination Charges

The Narragansett Electric Company Share (22.4%)
Variable Component
$ in Millions

Line	Year End (1)	Nuclear Decommissioning and Other Post-Shutdown Costs (2)	Power Contracts: Power Total Obligation (3)	Power Contracts: Assumed Market Value (4)	Power Contracts: Net: Excess Over Market (5)	Future Power Contract Buyouts (6)	Credit for Unit Sales Contracts: Power Total Obligation (7)	Credit for Unit Sales Contracts: Assumed Market Value (8)	Credit for Unit Sales Contracts: Net: Excess Over Market (9)	Above Market Fuel Transportation Costs (10)	Transmission in Support of Remote Generating Units (11)	Payments in Lieu of Property Taxes (12)	Employee Severance and Retraining Costs (13)	Damages, Costs, or Net Recoveries from Claims (14)	PBR for Nuclear Units Remaining After Market Valuation (15)	**Base Total Variable Component (16)**	Reconciliation Account (17)	**Total Variable Component Including Reconciliation Account (18)**
(1)	**1998**	**5.3**	**0.0**	**0.0**	**0.0**	**13.6**	**(0.5)**	**(0.4)**	**(0.1)**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**19.0**	**0.0**	**19.0**
(2)	**1999**	**12.5**	**0.0**	**0.0**	**0.0**	**40.8**	**(1.7)**	**(1.2)**	**(0.5)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.1**	**(12.6)**	**40.5**
(3)	**2000**	**10.6**	**0.0**	**0.0**	**0.0**	**40.7**	**(1.6)**	**(1.2)**	**(0.4)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**51.2**	**(1.5)**	**49.7**
(4)	**2001**	**12.7**	**0.0**	**0.0**	**0.0**	**40.5**	**(0.4)**	**(0.2)**	**(0.2)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.3**	**(13.1)**	**40.2**
(5)	**2002**	**10.1**	**0.0**	**0.0**	**0.0**	**40.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**50.5**	**(16.6)**	**33.8**
(6)	January	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(7)	February	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(8)	March	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(9)	April	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(10)	May	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(11)	June	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(12)	July	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(13)	August	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(14)	September	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(15)	October	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(16)	November	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(17)	December	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(18)	**2003**	**6.3**	**0.0**	**0.0**	**0.0**	**37.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**43.7**	**(8.8)**	**34.9**
(19)	January	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(20)	February	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(21)	March	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(22)	April	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(23)	May	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(24)	June	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(25)	July	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(26)	August	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(27)	September	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(28)	October	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(29)	November	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(30)	December	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(31)	**2004**	**6.5**	**0.0**	**0.0**	**0.0**	**35.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**42.1**	**(9.6)**	**32.5**
(32)	2005	6	23	13	9	26	0	0	0	0	0	0	0	0	0	**42**	(7)	**35**
(33)	2006	8	28	16	11	22	0	0	0	0	0	0	0	(4)	0	**37**	(2)	**35**
(34)	2007	7	28	15	12	2	0	0	0	0	0	0	0	0	0	**21**	0	**21**
(35)	2008	6	27	12	15	1	0	0	0	0	0	0	0	0	0	**22**	0	**23**
(36)	2009	5	19	9	10	1	0	0	0	0	0	0	0	0	0	**17**	0	**17**
(37)	2010	5	17	9	9	0	0	0	0	0	0	0	0	0	0	**14**	0	**14**
(38)	2011	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(39)	2012	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	1	**9**
(40)	2013	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(41)	2014	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(42)	2015	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(43)	2016	0	11	5	6	0	0	0	0	0	0	0	0	0	0	**6**	(0)	**6**
(44)	2017	0	9	4	4	0	0	0	0	0	0	0	0	0	0	**4**	(0)	**4**
(45)	2018	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(46)	2019	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(47)	2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**

Column Notes:

Columns (2) through (16) represent 22.4% of the same Column number on Schedule 1, Page 15.
(17) See Schedule 2, Page 3, Column (6) x -1
(18) Column (16) + Column (17)

NO ADJUSTMENTS

New England Power Company's Generation Facilities
Net Capability and Unrecovered Costs
Based Upon Actuals

Source	Location	Year(s) Placed In-Service	Energy Source	Net Capability (MW)	$ Millions 1995		Sept 1, 1998 *		Applicable Annual Depreciation per W-95 (S) for the period: 1997	1998 and Beyond	
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)	(9)	
Fossil Fuel Units											
Brayton Point Station											
Units 1,2 & 3	Somerset, Mass.	1963-1969	Coal-Oil-Gas	1,130							
Unit 4		1974	Oil-Gas	446							
				1,576							
Salem Harbor Station											
Units 1,2 & 3	Salem, Mass.	1952-1958	Coal-Oil	314							
Unit 4		1972	Oil	400							
				714							
Other System Units	Me., Mass.	1963-1978	Oil	101							
Subtotal Brayton Point, Salem Harbor, and Other				2,391	$435		$353		$34.2	$34.2	(c)
Manchester St. Station	Prov., R.I.	1995	Oil-Gas	513	460	(a)	400	(a)	17.1	17.1	(d)
Hydroelectric Units											
Conventional	Mass., N.H. & Vt.	1909-1987	Water	577	169		150		3.7	3.7	
Pumped Storage											
Bear Swamp	Rowe, Mass.	1974	Water	589	73		65		1.8	1.8	
Nuclear Units											
Vermont Yankee	Vermont	1972	Nuclear	341	73	(b)	27	(b)	6.2	6.2	(e)
Millstone 3	Waterford, Conn.	1986	Nuclear	140	390	(b)	338	(b)	30.0	44.9	(f)
Seabrook 1	Seabrook, N.H.	1990	Nuclear	115	63	(b)	41	(b)	1.9	1.9	
Step-Up Transformers at Generation Facilities (Not Included in Transmission Rates)					12		10		0.4	0.4	
General Plant Allocated to Generation					10		8		0.3	0.3	
Generation Related Property Held For Future Use and Non-Utility Property					11		10		0.0	0.0	
Nantucket Generating Units (Not included in Transmission Rates)					0		0		0.0	0.0	
Total				**4,666**	**$1,695**		**$1,404**		**$95.6**	**$110.5**	

Notes:
(a) Includes prepaid taxes in accordance with tax treaty.
(b) Includes balances for final fuel core and materials and supplies.
(c) Depreciation includes dismantlement expense of $5 M and $3 M for Brayton Point and Salem Harbor, respectively, through the year 2004.
(d) Includes $3.3 M of annual amortization of prepaid taxes which ends 2002.
(e) Depreciation based upon years remaining under license. Vermont Yankee license expires 2012.
(f) Millstone 3 base amortization was adjusted for acceleration per W-95S in 1996 and 1997. Accelerated amortization for 1998.
is as noted in the table and an additional $1.2 M of amortization should be added each year thereafter until fully depreciated.

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company Generation Related
Regulatory Asset Balances
$ in Millions

	Balance as of December 31, 1995	Balance as of Sept 1, 1998 *	Applicable Annual Depreciation per W-95 (S) for the period: 1997	Applicable Annual Depreciation per W-95 (S) for the period: 1998 and Beyond	Basis for Deferral
	(1)	(2)	(3)	(4)	(5)
FAS 109	$28	$21	0.9	0.9	FERC Ratemaking Policy
Unamortized Losses on Reacquired Debt	26	23	1.8	1.8	FERC Ratemaking Policy
Pipeline Demand Charges	58	49	2.3	2.3	Settlement Agreement (1)
NEEI	226	130	18.0	21.2	Settlement Agreement (2)
FAS 106 Deferral	13	1	11.0	0.0	FERC Ratemaking Policy
Power Contract Buyouts	24	16	3.9	3.9	Settlement Agreement (3)
Property Losses	5	0	0.0	0.0	Settlement Agreement (2)
Rate Clauses	5	3	0.7	0.7	Settlement Agreement (4)
South Street Cost of Removal	8	2	3.9	0.0	Settlement Agreement (3)
Brayton Point Rotor	9	2	4.2	0.0	Settlement Agreement (3)
Seabrook Tax True-Up	2	2	0.0	0.0	Settlement Agreement (2)
Decontamination & Decommissioning Costs	2	3	0.2	0.2	FERC Ratemaking Policy
W-95S Adjustment Account	2	(10)	0.3	0.0	Settlement Agreement (3)
Unamortized ITC	(23)	(21)	(1.2)	(1.2)	FERC Ratemaking Policy
Total Regulatory Assets	**$384**	**$222**	**$46.0**	**$29.9**	

Settlement Agreement Notes:

(1) W-92 Settlement Agreement - FERC Docket Nos. ER91-565-000 and ER91-566-000
(2) W-9 Settlement Agreement - FERC Docket No. ER88-86-000
(3) W-95 Settlement Agreement - FERC Docket Nos. ER95-267-000
(4) Surcharge Compliance Filing Settlement, FERC Docket Nos. ER88-630-000 et al. (Rate W-10), ER89-582-000 et al. (Rate W-11), and ER90-525-000 et al. (Rate W-12)

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company

FAS 106 Transition Obligation Regulatory Asset

$ in Millions

Unrecovered Balance as of 9/1/98 per Pre-Divestiture	$61.5	
Less: Unrecognized Gain/(Loss) Allocated to Generation	25.4	(a)
Unrecovered Balance as of 9/1/98	**$36.1**	
Actuarial Discount Rate	6.75%	
Amortization (straightline)	11.3	years

Line		Amortization (1)	Interest (2)	Total Expense (3)	Unamortized Balance (4)
(1)	**Unrecovered Balance as of 9/1/98**				**36.1**
(2)	**1998**	**1.1**	**2.4**	**3.5**	**35.1**
(3)	**1999**	**3.2**	**2.3**	**5.4**	**31.9**
(4)	**2000**	**3.2**	**2.0**	**5.2**	**28.7**
(5)	**2001**	**3.2**	**1.8**	**5.0**	**25.5**
(6)	**2002**	**3.2**	**1.6**	**4.8**	**22.3**
(7)	**2003**	**3.2**	**1.4**	**4.6**	**19.1**
(8)	**2004**	**3.2**	**1.2**	**4.4**	**15.9**
(9)	2005	3.2	1.0	**4.2**	12.8
(10)	2006	3.2	0.8	**3.9**	9.6
(11)	2007	3.2	0.5	**3.7**	6.4
(12)	2008	3.2	0.3	**3.5**	3.2
(13)	2009	3.2	0.1	**3.3**	0.0
		36.1			

Column Notes:
(1) Column (4), line (1)/11.33.
(2) (Prior year Column (4) + Current year Column (4))/2 x .0675
(3) Column (1) + Column (2).
(4) Prior year Column (4) - Column (1).

New England Power Company Share of Total Nuclear Post-Shutdown Costs

Based Upon Original Estimates

$ in Millions

	Millstone 3 (1)	**Seabrook 1** (2)	**Vermont Yankee** (3)	**Total** (4)
1998	0	0	0	**0**
1999	0	0	0	**0**
2000	0	0	0	**0**
2001	7	6	7	**20**
2002	0	6	7	**13**
2003	0	0	0	**0**
2004	0	0	0	**0**
2005	0	0	0	**0**
2006	0	0	0	**0**
2007	0	0	0	**0**
2008	0	0	0	**0**
2009	0	0	0	**0**
2010	0	0	0	**0**
2011	0	0	0	**0**
2012	0	0	0	**0**
2013	0	0	0	**0**
2014	0	0	0	**0**
2015	0	0	0	**0**
2016	0	0	0	**0**
2017	0	0	0	**0**
2018	0	0	0	**0**
2019	0	0	0	**0**
2020	0	0	0	**0**
2021	0	0	0	**0**
2022	0	0	0	**0**
2023	0	0	0	**0**
2024	0	0	0	**0**
2025	0	0	0	**0**
2026	0	0	0	**0**
2027	0	0	0	**0**
2028	0	0	0	**0**
2029	0	0	0	**0**

Column Notes:
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(3) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

New England Power Company Share of Total Annual Decommissioning Cost

Based Upon Revised Estimates

$ in Millions

	Millstone 3 (1)	Seabrook 1 (2)	Connecticut Yankee (3)	Vermont Yankee (4)	Maine Yankee (5)	Yankee Atomic (6)	Total Nuclear Decommissioning (7)
Sept 1, 1998	0	0	8	1	9	5	**24**
1999	1	1	17	2	19	15	**56**
2000	2	2	16	3	17	8	**48**
2001	2	2	15	3	16	0	**37**
2002	0	2	13	3	14	0	**32**
2003	0	0	13	0	15	0	**28**
2004	0	0	13	0	16	0	**29**
2005	0	0	13	0	16	0	**29**
2006	0	0	19	0	12	4	**35**
2007	0	0	17	0	12	4	**32**
2008	0	0	14	0	10	4	**28**
2009	0	0	14	0	7	4	**25**
2010	0	0	14	0	6	4	**24**
2011	0	0	0	0	0	0	**0**
2012	0	0	0	0	0	0	**0**
2013	0	0	0	0	0	0	**0**
2014	0	0	0	0	0	0	**0**
2015	0	0	0	0	0	0	**0**
2016	0	0	0	0	0	0	**0**
2017	0	0	0	0	0	0	**0**
2018	0	0	0	0	0	0	**0**
2019	0	0	0	0	0	0	**0**
2020	0	0	0	0	0	0	**0**
2021	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	**0**

Column Notes
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(4) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

Columns (3), (5), and (6) reflect permanent shutdown of Connecticut Yankee, Maine Yankee, and Yankee Atomic units and thus include both post-shutdown and decommissioning costs.

Power Contract Buyout Payments Associated with Divestiture
Per IPP Transfer Agreement

$ Millions

	Milford Power	Ridgewood	Resco Saugus	Wheelabrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	Total
2005	34.7	5.5	16.8	26.6	3.3	0.1	0.1	14.0	101.1
2006	40.1	7.7	22.8	35.1	4.3		0.2	13.5	123.7
2007	40.0	7.8	23.2	35.7	4.2		0.0	12.3	123.2
2008	37.2	8.0	23.6	36.4	4.0			11.6	120.7
2009	2.7	8.2	24.0	37.0	3.8			11.2	86.9
2010		0.7	24.4	37.7	3.7			10.9	77.4
2011			24.8	38.4	3.5			10.6	77.3
2012			24.2	39.2				10.3	73.7
2013			25.7	39.9				10.0	75.6
2014			26.1	40.7				9.7	76.5
2015			26.6	41.5				7.5	75.6
2016				42.3				6.4	48.8
2017				31.9				6.2	38.1
2018								6.0	6.0
2019								5.0	5.0
2020								1.2	1.2

Power Contract Obligations
Estimated Market Value

Based Upon Revised Estimates

$'s in millions

	Milford Power	Ridgewood	Resco Saugus	Wheelebrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	TOTAL
2005	13.2	5.7	14.6	21.0	4.2	0.0	0.1	1.4	**60.2**
2006	10.4	8.2	19.6	26.5	6.2		0.3	1.3	**72.4**
2007	10.6	7.6	18.6	24.9	5.8		0.0	1.2	**68.7**
2008	8.8	5.9	14.8	19.4	4.7			1.2	**54.8**
2009	0.2	5.3	13.4	17.4	4.2			1.1	**41.6**
2010		0.5	14.2	18.5	4.4			1.1	**38.8**
2011			14.7	19.1	4.6			1.1	**39.4**
2012			15.4	20.0				1.0	**36.4**
2013			16.0	20.7				1.0	**37.7**
2014			16.9	22.1				1.0	**40.0**
2015			17.6	22.9				0.8	**41.2**
2016				23.2				0.6	**23.9**
2017				17.7				0.6	**18.3**
2018								0.6	**0.6**
2019								0.5	**0.5**
2020								0.1	**0.1**

New England Power Company
Annual Utility Unit Sales Power Contracts

Based Upon Original Estimates

$ in Millions

	OSP	Maine Yankee	Millstone 3	Millstone3/ Seabrook 1	**TOTAL**
	(1)	(2)	(3)	(4)	(5)
1997	5	0	1	5	**12**
1998	0	1	1	5	**7**
1999	0	0	1	6	**8**
2000	0	1	1	6	**7**
2001	0	1	1		**2**
2002	0	0	0		**0**
2003	0	0	0		**0**
2004	0	0	0		**0**
2005	0	0	0		**0**
2006	0	0	0		**0**
2007	0				**0**
2008	0				**0**
2009	0				**0**
2010	0				**0**

Column Notes:

Estimates have been set to zero. Actual unit sales are reflected in the Nuclear PBR.

NO ADJUSTMENTS

New England Power Company
Fixed Costs of Gas Transportation
Contractual Commitments

Based Upon Original Estimates

Annual Expenses

$ in Millions

	Total Pipeline Demand Charge Obligation (1)	Assumed by USGen NE (2)	Excess (3)	Total Energy Enterprise Minimum Payments (4)	Assumed by USGen NE (5)	Excess (6)	**Total Above Market Fuel Transportation Costs (7)**
Sept 1, 1998	31	31	0	6	6	0	**0**
1999	60	60	0	13	13	0	**0**
2000	60	60	0	13	13	0	**0**
2001	59	59	0	14	14	0	**0**
2002	58	58	0	14	14	0	**0**
2003	57	57	0	15	15	0	**0**
2004	56	56	0	13	13	0	**0**
2005	55	55	0	14	14	0	**0**
2006	54	54	0	14	14	0	**0**
2007	41	41	0	14	14	0	**0**
2008	40	40	0	15	15	0	**0**
2009	35	35	0	15	15	0	**0**
2010	35	35	0	16	16	0	**0**
2011	34	34	0	1	1	0	**0**
2012	30	30	0	0	0	0	**0**
2013	29	29	0	0	0	0	**0**
2014	16	16	0	0	0	0	**0**

Columns Notes:

(2) All payments assumed by USGen NE.
(3) Column (1) - Column (2).
(5) All payments assumed by USGen NE.
(6) Column (4) - Column (5).
(7) Column (3) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges

New England Power Company (100%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	**1998**	**50.5**	**202.2**		**1.2**	**253.8**	**NA**	**253.8**
(2)	**1999**	**106.6**	**654.0**	**95.5**	**5.4**	**861.5**	**NA**	**861.5**
(3)	**2000**	**53.1**	**674.3**		**5.2**	**732.6**	**NA**	**732.6**
(4)	**2001**	**24.5**	0.0		**5.0**	**29.6**	**NA**	**29.6**
(5)	**2002**	**22.4**	0.0		**4.8**	**27.2**	**NA**	**27.2**
(6)	January	1.7	0.0		0.4	**2.1**	NA	**2.1**
(7)	February	1.7	0.0		0.4	**2.1**	NA	**2.1**
(8)	March	1.7	0.0		0.4	**2.1**	NA	**2.1**
(9)	April	1.7	0.0		0.4	**2.1**	NA	**2.1**
(10)	May	1.7	0.0		0.4	**2.1**	NA	**2.1**
(11)	June	1.7	0.0		0.4	**2.1**	NA	**2.1**
(12)	July	1.7	0.0		0.4	**2.1**	NA	**2.1**
(13)	August	1.7	0.0		0.4	**2.1**	NA	**2.1**
(14)	September	1.7	0.0		0.4	**2.1**	NA	**2.1**
(15)	October	1.7	0.0		0.4	**2.1**	NA	**2.1**
(16)	November	1.7	0.0		0.4	**2.1**	NA	**2.1**
(17)	December	1.7	0.0		0.4	**2.1**	NA	**2.1**
(18)	**2003**	**20.4**	**0.0**		**4.6**	**25.0**	**NA**	**25.0**
(19)	January	1.5	0.0		0.4	**1.9**	NA	**1.9**
(20)	February	1.5	0.0		0.4	**1.9**	NA	**1.9**
(21)	March	1.5	0.0		0.4	**1.9**	NA	**1.9**
(22)	April	1.5	0.0		0.4	**1.9**	NA	**1.9**
(23)	May	1.5	0.0		0.4	**1.9**	NA	**1.9**
(24)	June	1.5	0.0		0.4	**1.9**	NA	**1.9**
(25)	July	1.5	0.0		0.4	**1.9**	NA	**1.9**
(26)	August	1.5	0.0		0.4	**1.9**	NA	**1.9**
(27)	September	1.5	0.0		0.4	**1.9**	NA	**1.9**
(28)	October	1.5	0.0		0.4	**1.9**	NA	**1.9**
(29)	November	1.5	0.0		0.4	**1.9**	NA	**1.9**
(30)	December	1.5	0.0		0.4	**1.9**	NA	**1.9**
(31)	**2004**	**18.5**	**0.0**		**4.4**	**22.9**	**NA**	**22.9**
(32)	2005	17	0		4	**21**	NA	**21**
(33)	2006	15	0		4	**19**	NA	**19**
(34)	2007	13	0		4	**17**	NA	**17**
(35)	2008	11	0		4	**15**	NA	**15**
(36)	2009	9	0		3	**13**	NA	**13**
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
(1) Annual totals for 1998 - 2002 Reconciliations, monthly for 2003-2004; annual thereafter
(2) See Schedule 1, Page 14, Column (9).
(3) For years 1998-1999 Column (3) = [Schedule 1, Page 1, Column (10) x Schedule 1, Page 1, Column (4)]/100/.224 - Schedule 1, Page 15, Column (16) - Schedule 1, Page 12, Columns (2) and (4).
For 2000, Column (3) = Page 14, Column (2).
(4) Schedule 1, Page 5a, Column (3) x Page 1, Column (3).
(5) Sum of Columns (2) through (4).
(6) Not applicable at NEP level. See Schedule 1, Page 2, Column (6) for Narragansett Residual Value Credit.
(7) Column (5) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Deferred Taxes on Fixed Component

$ in Millions

Line	Year End (1)	Book Basis: Balance Net Book Value of Generation (2)	Book Basis: Balance Generation Related Regulatory Assets (3)	Book Basis: Total Net Book Basis (4)	Tax Basis: Balance Net Book Value of Generation (5)	Tax Basis: Balance Generation Related Regulatory Assets (6)	**Total Tax Basis** (7)	**Excess Book Over Tax (8)**	**Deferred Taxes (9)**
Pre-Divest End Balances		**$1,435**	**$202**	**$1,636**	**$696**				
Less: Maine Yankee and ITC		31	(20)	10	14				
Post-Divest Start Balances		$1,404	$222	$1,626	$682				
(1)	**Sept 1, 1998**	**1,404**	**222**	**1,626**	**682**	**0**	**682**	**944**	**370**
(2)	**1998**	**1,229**	**195**	**1,424**	**652**	**0**	**652**	**771**	**303**
(3)	**1999**	**582**	**92**	**674**	**571**	**0**	**571**	**103**	**40**
(4)	**2000**	**0**	**0**	**0**	**521**	**0**	**521**	**(521)**	**(204)**
(5)	**2001**	**0**	**0**	**0**	**475**	**0**	**475**	**(475)**	**(186)**
(6)	**2002**	**0**	**0**	**0**	**433**	**0**	**433**	**(433)**	**(170)**
(7)	**2003**	**0**	**0**	**0**	**395**	**0**	**395**	**(395)**	**(155)**
(8)	**2004**	**0**	**0**	**0**	**357**	**0**	**357**	**(357)**	**(140)**
(9)	2005	0	0	0	320	0	**320**	**(320)**	**(125)**
(10)	2006	0	0	0	282	0	**282**	**(282)**	**(111)**
(11)	2007	0	0	0	246	0	**246**	**(246)**	**(96)**
(12)	2008	0	0	0	209	0	**209**	**(209)**	**(82)**
(13)	2009	0	0	0	175	0	**175**	**(175)**	**(69)**

Column Notes:
(2) See Pre-Divestiture Schedule 1, for August 31,1998 balances. For year end 1997-2009, Column (2) prior year - (Schedule 1, Page 12, Column (3) current year x (Column (2) Line1/Column (4) Line 1).
(3) See Pre-Divestiture Schedule 1, for August 31,1988 balances. For year end 1997-2009, Column (3) prior year-(Schedule 1, Page 12, Column (3) current year x (Column (3) Line1/Column (4) Line 1).
(4) Column (2) + Column (3).
(5) Per tax records of the Company.
(6) Per tax records of the Company.
(7) Column (5) + Column (6).
(8) Column (4) - Column (7).
(9) Column (8) x tax rate of .39225.

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Return on Fixed Component

Line	Year End (1)	Base Return: Balance of Fixed Component (2)	Base Return: Deferred Taxes (3)	Base Return: Net Balance (4)	Average Net Balance (5)	Subtotal Annual Return on Unamortized Balance (6)	Less: Return on Rate Clauses (7)	Plus: Return on Unamortized ITC (8)	Total Annual Return on Unamortized Balance (9)
(1)	Sept 1, 1998	$1,626	$370	$1,256					
(2)	**1998**	**1,424**	**303**	**1,121**	**$1,188**	**$50**	**($0.1)**	**$0.8**	**$50**
(3)	**1999**	**674**	**40**	**634**	**837**	**105**	**(0.1)**	**1.6**	**107**
(4)	**2000**	**0**	**(204)**	**204**	**419**	**53**	**(0.0)**	**0.5**	**53**
(5)	**2001**	**0**	**(186)**	**186**	**195**	**25**	**0.0**	**0.0**	**25**
(6)	**2002**	**0**	**(170)**	**170**	**178**	**22**	**0.0**	**0.0**	**22**
(7)	**2003**	**0**	**(155)**	**155**	**162**	**20**	**0.0**	**0.0**	**20**
(8)	**2004**	**0**	**(140)**	**140**	**148**	**19**	**0.0**	**0.0**	**19**
(9)	2005	0	(125)	125	133	17	0.0	0.0	**17**
(10)	2006	0	(111)	111	118	15	0.0	0.0	**15**
(11)	2007	0	(96)	96	104	13	0.0	0.0	**13**
(12)	2008	0	(82)	82	89	11	0.0	0.0	**11**
(13)	2009	0	(69)	69	75	9	0.0	0.0	**9**

Column Notes:
(2) See Schedule 1, Page 13, Column (4).
(3) See Schedule 1, Page 13, Column (9).
(4) Column (2) - Column (3).
(5) (Column (4) Prior Year + Column (4))/2.
(6) Column (5) x Total Pre-Valuation Rate of Return of 11.01% x Schedule 1, Page 1, Column (3).
(7) Average of (Unamortized Balance of Rate Clauses - Deferred Taxes on Rate Clauses) x 11.18% x Page 1, Column (3).
(8) Average of Unamortized Balance of ITC x 11.18% x Page 1, Column (3).
(9) Column (6) + Column (7) + Column (8).

Note: Savings from refinancing calculated as difference between 12.56% and 12.16% are included in the Reconciliation Account.

* Actual September 30, 1998 capital structure with pro-forma adjustments for known preferred stock redemptions which occurred in October and November.

Return Component	*BASE* Post-Divestiture Year End 1995	*REFINANCED* Post-Divestiture September * 1998
Capital Structure:		
LTD	44.07%	42.44%
Preferred	3.56%	0.21%
Common Equity	52.37%	57.35%
	100.00%	100.00%
Cost Rates:		
LTD	6.23%	4.15%
Preferred	5.69%	6.00%
Common Equity	11.00%	11.00%
Total Weighted Cost Rate	**8.71%**	**8.08%**
Reimbursement for Taxes on Equity Component	**3.85%**	**4.08%**
Total Rate of Return	**12.56%**	**12.16%**

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Variable Component

$ in Millions

			Power Contracts				Credit for Unit Sales Contracts									
Line	Year End (1)	Nuclear Decommissioning and Other Post-Shutdown Costs (2)	Total Obligation (3)	Assumed Market Value (4)	Excess Over Market (5)	Future Power Contract Buyouts (6)	Total Revenue (7)	Assumed Market Value (8)	Excess Over Market (9)	Above Market Fuel Transportation Costs (10)	Transmission in Support of Remote Generating Units (11)	Payments in Lieu of Property Taxes (12)	Employee Severance and Retraining Costs (13)	Damages, Costs, or Net Recoveries from Claims (14)	PBR for Nuclear Units Remaining After Market Valuation (15)	**Base Total Variable Component (16)**
(1)	**1998**	**23.8**	**0.0**	**0.0**	**0.0**	**60.8**	**(2.4)**	**(1.9)**	**(0.5)**	**0.0**	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**	**84.6**
(2)	**1999**	**55.7**	**0.0**	**0.0**	**0.0**	**182.1**	**(7.6)**	**(5.4)**	**(2.2)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.0**
(3)	**2000**	**47.5**	**0.0**	**0.0**	**0.0**	**181.4**	**(7.4)**	**(5.4)**	**(2.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**228.4**
(4)	**2001**	**56.6**	**0.0**	**0.0**	**0.0**	**180.7**	**(1.7)**	**(0.7)**	**(1.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.8**
(5)	**2002**	**45.1**	**0.0**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**225.2**
(6)	January	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(7)	February	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(8)	March	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(9)	April	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(10)	May	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(11)	June	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(12)	July	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(13)	August	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(14)	September	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(15)	October	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(16)	November	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(17)	December	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(18)	**2003**	**28.2**	**0.0**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**195.1**
(19)	January	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(20)	February	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(21)	March	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(22)	April	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(23)	May	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(24)	June	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(25)	July	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(26)	August	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(27)	September	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(28)	October	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(29)	November	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(30)	December	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(31)	**2004**	**29.1**	**0.0**	**0.0**	**0.0**	**158.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**187.9**
(32)	2005	29	101	60	41	117	0	0	0	0	0	0	0	0	0	**187**
(33)	2006	35	124	72	51	97	0	0	0	0	0	0	0	(17)	0	**166**
(34)	2007	32	123	69	54	7	0	0	0	0	0	0	0	0	0	**93**
(35)	2008	28	121	55	66	6	0	0	0	0	0	0	0	0	0	**100**
(36)	2009	25	87	42	45	6	0	0	0	0	0	0	0	0	0	**75**
(37)	2010	24	77	39	39	0	0	0	0	0	0	0	0	0	0	**62**
(38)	2011	0	77	39	38	0	0	0	0	0	0	0	0	0	0	**38**
(39)	2012	0	74	36	37	0	0	0	0	0	0	0	0	0	0	**37**
(40)	2013	0	76	38	38	0	0	0	0	0	0	0	0	0	0	**38**
(41)	2014	0	77	40	37	0	0	0	0	0	0	0	0	0	0	**37**
(42)	2015	0	76	41	34	0	0	0	0	0	0	0	0	0	0	**34**
(43)	2016	0	49	24	25	0	0	0	0	0	0	0	0	0	0	**25**
(44)	2017	0	38	18	20	0	0	0	0	0	0	0	0	0	0	**20**
(45)	2018	0	6	1	5	0	0	0	0	0	0	0	0	0	0	**5**
(46)	2019	0	5	0	5	0	0	0	0	0	0	0	0	0	0	**5**
(47)	2020	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(All Sources based upon estimates of Variable Costs)
(2) (Schedule 1, Page 6, Column (4) + Schedule 1, Page 7, Column (7)) x Schedule 1, Page 1, Column (3).
(5) Column (3) - Column (4).
(6) Per NEP/USGen "IPP Contract Transfer Agreement".
(7) Schedule 1, Page 10, Column (5) x Schedule 1, Page 1, Column (3).
(9) Column (7) - Column (8).
(10) Schedule 1, Page 11, Column (7) x Schedule 1, Page 1, Column (3).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

Reconciliation Adjustment

The Narragansett Electric Company Share

Revenue Adjustments

Line	Year (1)	Estimated Kwh Delivered (2)	Actual Kwh Delivered (3)	Delta Kwh Delivered (4)	Termination Charge Billed (5)	Narragansett Revenue Excess/ (Shortfall) (6)	
(1)	**1998**	**1,626**	**1,669**	**42**	**1.50**	**1.8**	***NO ADJUSTMENTS TO SEPTEMBER***
(2)	**1999**	**5,013**	**5,175**	**162**	**1.58**	**1.9**	
(3)	**2000**	**5,165**	**5,271**	**106**	**1.15**	**1.2**	
(4)	**2001**	**5,183**	**5,387**	**204**	**0.80**	**2.5**	
(5)	**2002**	**5,232**	**5,557**	**325**	**0.67**	**2.5**	
(6)	January	441	509	69	pro-rated	0.4	
(7)	February	441	468	28	**0.68**	0.2	
(8)	March	441	365	(76)	**0.68**	(0.5)	
(9)	April	441	420	(21)	**0.68**	(0.1)	
(10)	May	441	412	(29)	**0.68**	(0.2)	
(11)	June	441	421	(20)	**0.68**	(0.1)	
(12)	July	441	509	69	**0.68**	0.5	
(13)	August	441	661	220	**0.68**	1.5	
(14)	September	441	511	70	**0.68**	0.5	
(15)	October	441	444	4	**0.68**	0.0	
(16)	November	441	439	(1)	**0.68**	(0.0)	
(17)	December	441	488	48	**0.68**	0.3	
(18)	**2003**	**5,288**	**5,648**	**360**	**0.68**	**2.4**	
(19)	January	446	531	85	pro-rated	0.7	
(20)	February	446	487	41	**0.63**	0.3	
(21)	March	446	457	10	**0.63**	0.1	
(22)	April	446	440	(6)	**0.63**	0.0	
(23)	May	446	413	(33)	**0.63**	(0.2)	
(24)	June	446	455	9	**0.63**	0.1	
(25)	July	446	506	60	**0.63**	0.4	
(26)	August	446	527	81	**0.63**	0.5	
(27)	September	446	544	97	**0.63**	0.6	
(28)	October	446	446	0	**0.63**	0.0	
(29)	November	446	446	0	**0.63**	0.0	
(30)	December	446	446	0	**0.63**	0.0	
(31)	**2004**	**5,356**	**5,356**	**344**	**0.63**	**2.3**	
(32)	2005	5,428	5,428	0	0.67	0	
(33)	2006	5,496	5,496	0	0.66	0	
(34)	2007	5,562	5,562	0	0.40	0	
(35)	2008	5,628	5,628	0	0.42	0	
(36)	2009	5,695	5,695	0	0.31	0	
(37)	2010	5,783	5,783	0	0.24	0	
(38)	2011	5,864	5,864	0	0.15	0	
(39)	2012	5,946	5,946	0	0.15	0	
(40)	2013	6,029	6,029	0	0.14	0	
(41)	2014	6,114	6,114	0	0.13	0	
(42)	2015	6,199	6,199	0	0.12	0	
(43)	2016	6,286	6,286	0	0.09	0	
(44)	2017	6,374	6,374	0	0.07	0	
(45)	2018	6,463	6,463	0	0.02	0	
(46)	2019	6,554	6,554	0	0.01	0	
(47)	2020	6,646	6,646	0	0.00	0	
(48)	2021	6,739	6,739	0	0.00	0	
(49)	2022	6,833	6,833	0	0.00	0	
(50)	2023	6,929	6,929	0	0.00	0	
(51)	2024	7,026	7,026	0	0.00	0	
(52)	2025	7,124	7,124	0	0.00	0	
(53)	2026	7,224	7,224	0	0.00	0	
(54)	2027	7,325	7,325	0	0.00	0	
(55)	2028	7,427	7,427	0	0.00	0	
(56)	2029	7,531	7,531	0	0.00	0	

Column Notes:
(2) See Schedule 1, Page 1, Column (2).
(3) Actual Kwh delivered.
(4) Column (3) - Column (2).
(5) See Schedule 1, Page 1, Column (10).
(6) Column (4) x Column (5)/100.

Reconciliation Adjustment

(continued from page 2a)

The Narragansett Electric Company Share

New England Power Company Variable Cost Adjustments

Line		Estimated Base Variable Component (7)	Actual Nuclear Decommissioning Costs (8)	Actual Power Contracts Obligations (9)	Actual Power Contracts Market Value (10)	Actual Power Contract Buyouts (11)	Actual Unit Sales Contracts Revenue (12)	Actual Unit Sales Contracts Market Value (13)	Actual Above Market Fuel Transportation Costs (14)	Actual Transmission in Support of Remote Generating Units (15)	Actual Payments in Lieu of Property Taxes (16)	Actual Employee Severance and Retraining Costs (17)	Actual Damages, Costs, or Net Recoveries from Claims (18)	Actual PBR for Nuclear Units Remaining After Market Valuation (19)	Actual Environmental Response Costs (20)	NEP Actual Total Variable Component (21)	Delta Variable Component (22)	Narragansett Share of Delta Variable Component (23)	**Narragansett Annual Reconciliation Adjustment Excess/ (Shortfall)** (24)
(1)	**1998**	**84.6**	**17.2**	**0.0**	**0.0**	**60.8**	**(1.8)**	**(1.6)**	**0.0**	**0.6**	**0.0**	**(17.8)**	**(1.4)**	**6.0**	**0.0**	**65.2**	**(19.4)**	**(4.3)**	**6.1**
(2)	**1999**	**237.0**	**43.8**	**0.0**	**0.0**	**182.1**	**0.0**	**0.0**	**0.0**	**1.2**	**0.0**	**1.4**	**(36.9)**	**17.3**	**0.0**	**208.8**	**(28.1)**	**(6.3)**	**8.2**
(3)	**2000**	**228.4**	**29.9**	**0.0**	**0.0**	**181.4**	**0.0**	**0.0**	**0.0**	**1.4**	**0.0**	**(0.7)**	**(20.8)**	**(17.5)**	**0.0**	**173.7**	**(54.7)**	**(12.3)**	**13.5**
(4)	**2001**	**237.8**	**27.5**	**0.0**	**0.0**	**180.7**	**0.0**	**0.0**	**0.0**	**0.3**	**0.0**	**0.0**	**(3.6)**	**6.2**	**0.8**	**212.0**	**(25.9)**	**(5.8)**	**8.3**
(5)	**2002**	**225.2**	**21.4**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(1.1)**	**(0.2)**	**0.6**	**1.9**	**202.7**	**(22.5)**	**(5.0)**	**7.5**
(6)	January	16.3	0.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.5)	0.2	14.9	(1.4)	(0.3)	0.7
(7)	February	16.3	2.2	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	17.0	0.8	0.2	0.0
(8)	March	16.3	1.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.4	0.1	0.0	(0.5)
(9)	April	16.3	1.5	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	16.1	(0.2)	(0.0)	(0.1)
(10)	May	16.3	1.6	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	15.7	(0.6)	(0.1)	(0.1)
(11)	June	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.6	0.4	0.1	(0.2)
(12)	July	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.5	0.2	0.1	0.4
(13)	August	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4	0.2	0.0	1.5
(14)	September	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	16.7	0.4	0.1	0.4
(15)	October	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.5	0.3	0.1	(0.0)
(16)	November	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	16.6	0.3	0.1	(0.1)
(17)	December	16.3	2.7	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	(0.1)	(0.0)	0.3
(18)	**2003**	**195.1**	**27.8**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(0.4)**	**1.2**	**195.6**	**0.5**	**0.1**	**2.3**
(19)	January	15.7	1.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	15.2	(0.4)	(0.1)	0.8
(20)	February	15.7	3.5	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	16.8	1.1	0.2	0.0
(21)	March	15.7	2.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.2	0.5	0.1	(0.1)
(22)	April	15.7	3.0	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	17.2	1.5	0.3	(0.4)
(23)	May	15.7	2.9	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.2	1.5	0.3	(0.5)
(24)	June	15.7	3.0	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.3	1.7	0.4	(0.3)
(25)	July	15.7	3.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	17.3	1.7	0.4	0.0
(26)	August	15.7	3.1	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.1	1.5	0.3	0.2
(27)	September	15.7	2.5	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.8	1.1	0.2	0.4
(28)	October	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(29)	November	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(30)	December	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(31)	**2004**	**187.9**	**34.4**	**0.0**	**0.0**	**164.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.7**	**199.2**	**11.3**	**2.5**	**(0.2)**
(32)	2005	187	46	101	60	117	0	0	0	0	0	0	0	0	0	204	17	(6)	6
(33)	2006	166	35	124	72	97	0	0	0	0	0	0	0	0	0	183	17	4	(4)
(34)	2007	93	32	123	69	7	0	0	0	0	0	0	0	0	0	93	0	0	0
(35)	2008	100	28	121	55	6	0	0	0	0	0	0	0	0	0	100	0	0	0
(36)	2009	75	25	87	42	6	0	0	0	0	0	0	0	0	0	75	0	0	0
(37)	2010	62	24	77	39	0	0	0	0	0	0	0	0	0	0	62	0	0	0
(38)	2011	38	0	77	39	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(39)	2012	37	0	74	36	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(40)	2013	38	0	76	38	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(41)	2014	37	0	77	40	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(42)	2015	34	0	76	41	0	0	0	0	0	0	0	0	0	0	34	0	0	0
(43)	2016	25	0	49	24	0	0	0	0	0	0	0	0	0	0	25	0	0	0
(44)	2017	20	0	38	18	0	0	0	0	0	0	0	0	0	0	20	0	0	0
(45)	2018	5	0	6	1	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(46)	2019	5	0	5	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(47)	2020	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						0													

Column Notes:
(7) See Schedule 1, Page 15, Column (16).
(8)-(20) Actual expenses incurred.
(21) Column (8) + Column (9) - Column (10) + Column (11) + Column (12) - Column (13) + Column (14) + Column (15) + Column (16) + Column (17) + Column (18) + Column (19) + Column (20).
(22) Column (21) - Column (7).
(23) Column (22) x 22.4%. Includes $10 million credit related to Settlement dated November 14, 2005.
(24) Schedule 2, Page 2a, Column (6) - Schedule 2, Page 2b, Column (23).

Reconciliation Account

The Narragansett Electric Company

The Narragansett Electric Company Account

Line	Year (1)	Reconciliation Adjustment (2)	Divestiture Related Adjustments per Section 1.1.4 (3)	Annual Shortfall/ (Excess) (4)	Pre-Tax Return on Balance (5)	Collection of Prior Year Balance Including Interest (6)	End of Year Account Balance (7)	Lump Sum Payment/ Narr Deferred Tax Funding (8)	Revised End of Year Account Balance (9)
						As of August 31, 1998	**(3.3)**		
(1)	**1998**	**(6.1)**	**(11.3)**	**(17.5)**	**(0.77)**	**0.0**	**(21.5)**		
(2)	**1999**	**(8.2)**	**(2.7)**	**(10.9)**	**(2.29)**	**12.6**	**(22.1)**	**17.5**	**(4.6)**
(3)	**2000**	**(13.5)**	**(1.5)**	**(12.3)**	**(1.30)**	**1.5**	**(16.7)**	**5.0**	**(11.7)**
(4)	**2001**	**(8.3)**	**(3.8)**	**(12.1)**	**(1.44)**	**13.1**	**(12.2)**		
(5)	**2002**	**(7.5)**	**(2.1)**	**(9.6)**	**(1.04)**	**16.6**	**(6.2)**		
(6)	January	(0.7)	(0.5)	(1.2)	(0.06)	0.7	(6.8)		
(7)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.7	(6.6)		
(8)	March	0.5	(0.5)	(0.0)	(0.07)	0.7	(5.9)		
(9)	April	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.7)		
(10)	May	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.4)		
(11)	June	0.2	(0.5)	(0.3)	(0.05)	0.7	(5.0)		
(12)	July	(0.4)	(0.5)	(0.9)	(0.05)	0.7	(5.2)		
(13)	August	(1.5)	(0.5)	(1.9)	(0.05)	0.7	(6.4)		
(14)	September	(0.4)	(0.5)	(0.9)	(0.07)	0.7	(6.6)		
(15)	October	0.0	(0.5)	(0.4)	(0.07)	0.7	(6.4)		
(16)	November	0.1	(0.5)	(0.4)	(0.07)	0.7	(6.2)		
(17)	December	(0.3)	(0.7)	(1.0)	(0.06)	0.7	(6.5)		
(18)	**2003**	**(2.3)**	**(6.1)**	**(8.4)**	**(0.73)**	**8.8**	**(6.5)**		
(19)	January	(0.8)	(0.5)	(1.3)	(0.07)	0.8	(7.1)		
(20)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.8	(6.8)		
(21)	March	0.1	(0.5)	(0.5)	(0.07)	0.8	(6.6)		
(22)	April	0.4	(0.6)	(0.2)	(0.07)	0.8	(6.1)		
(23)	May	0.5	(0.4)	0.1	(0.06)	0.8	(5.2)		
(24)	June	0.3	(0.5)	(0.2)	(0.05)	0.8	(4.7)		
(25)	July	(0.0)	(0.5)	(0.5)	(0.05)	0.8	(4.4)		
(26)	August	(0.2)	(0.5)	(0.7)	(0.04)	0.8	(4.4)		
(27)	September	(0.4)	(0.5)	(0.9)	(0.04)	0.8	(4.5)		
(28)	October	0.1	(0.5)	(0.4)	(0.05)	0.8	(4.1)		
(29)	November	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.8)		
(30)	December	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.5)		
(31)	**2004**	**0.2**	**(6.1)**	**(5.9)**	**(0.65)**	**9.6**	**(3.5)**		
(32)	2005	(6)	(6)	-12	0	7	-9	10.0	0.7
(33)	2006	4	(4)	0	0	2	3		
(34)	2007	0	(0)	0	0	0	2		
(35)	2008	0	(0)	0	0	0	2		
(36)	2009	0	(0)	0	0	0	1		
(37)	2010	0	0	0	0	0	1		
(38)	2011	0	0	0	0	0	1		
(39)	2012	0	0	0	0	-1	0		
(40)	2013	0	0	0	0	0	0		
(41)	2014	0	0	0	0	0	0		
(42)	2015	0	0	0	0	0	0		
(43)	2016	0	0	0	0	0	0		
(44)	2017	0	0	0	0	0	0		
(45)	2018	0	0	0	0	0	0		
(46)	2019	0	0	0	0	0	0		
(47)	2020	0	0	0	0	0	0		
(48)	2021	0	0	0	0	0	0		
(49)	2022	0	0	0	0	0	0		
(50)	2023	0	0	0	0	0	0		
(51)	2024	0	0	0	0	0	0		
(52)	2025	0	0	0	0	0	0		
(53)	2026	0	0	0	0	0	0		
(54)	2027	0	0	0	0	0	0		
(55)	2028	0	0	0	0	0	0		
(56)	2029	0	0	0	0	0	0		

Column Notes:

(2) See Schedule 2, Page 2b, Column (24) x -1.
(3) See Schedule 2, Page 5.
(4) Sum Columns (2) and (3). September 2000 includes unbilled revenue of $2.7m.
(5) Column (7) prior period (on average for 1/2 year) x 12.16%.
(6) In 1999, collection per 1998 CTC Reconciliation Filing; In 2000, collection represents 1999 balance per 1998 CTC Reconciliation filing plus return calculated based on mid year convention as a result of the lump sum payment. In 2001, Column (9) prior year x -1 + Column (5) current year.
In 2002 - 2029, Column (7) prior year x -1 - Column (5) current year. 2004 reflects unbilled revenue adjustment of $2.8m, 2005 reflects unbilled revenue of $2.6 million.
(7) Prior year Column (7) + current year Sum Column (4) through (6).
(8) The $17.5 million represents lump sum payment made by New England Power Company to The Narragansett Electric Company in December 1999.
The $5 million payment is to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.
The $10 million payment relates to a Settlement Agreement dated November 14, 2005.

Reconciliation Adjustment

New England Power Company (100%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

Line	Year (1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Transaction Costs (16)	TOTAL (17)
(1)	**1998**	**(2.121)**	**(27.968)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.344)**	**0.000**	**0.000**	**(0.620)**	**0.000**	**0.000**	**0.282**	**(30.770)**
(2)	**1999**	**(5.957)**	**0.000**	**(2.000)**	**(1.040)**	**(2.202)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.595)**	**(0.547)**	**0.154**	**(12.188)**
(3)	**2000**	**(5.853)**	**0.000**	**0.245**	**0.000**	**0.007**	**0.000**	**0.000**	**0.000**	**(1.135)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.736)**
(4)	**2001**	**(5.804)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.415)**	**(1.300)**	**(9.607)**	**(0.038)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(17.165)**
(5)	**2002**	**(5.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.078**	**(0.599)**	**(3.090)**	**0.000**	**0.000**	**0.000**	**0.000**	**(9.411)**
(6)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	(0.110)	(1.530)	0.000	0.000	0.000	0.000	(2.121)
(7)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.088)	(1.551)	0.000	0.000	0.000	0.000	(2.121)
(8)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.376)	(1.551)	0.000	0.000	0.000	0.000	(2.410)
(9)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.186)	(1.550)	0.000	0.000	0.000	0.000	(2.218)
(10)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.107)	(1.551)	0.000	0.000	0.000	0.000	(2.141)
(11)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.127)	(1.551)	0.000	0.000	0.000	0.000	(2.161)
(12)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.139)	(1.551)	0.000	0.000	0.000	0.000	(2.173)
(13)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.117)	(1.551)	0.000	0.000	0.000	0.000	(2.151)
(14)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.154)	(1.551)	0.000	0.000	0.000	0.000	(2.188)
(15)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.099)	(1.551)	0.000	0.000	0.000	0.000	(2.133)
(16)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.189)	(1.551)	0.000	0.000	0.000	0.000	(2.223)
(17)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.841)	(1.761)	0.000	0.000	0.000	0.000	(3.085)
(18)	**2003**	**(5.796)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.002**	**(2.531)**	**(18.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.125)**
(19)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.184)	(1.551)	0.000	0.000	0.000	0.000	(2.218)
(20)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.172)	(1.551)	0.000	0.000	0.000	0.000	(2.206)
(21)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.406)	(1.551)	0.000	0.000	0.000	0.000	(2.440)
(22)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.192)	(1.939)	0.000	0.000	0.000	0.000	(2.614)
(23)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.165)	(1.322)	0.000	0.000	0.000	0.000	(1.970)
(24)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.191)	(1.551)	0.000	0.000	0.000	0.000	(2.225)
(25)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.216)	(1.551)	0.000	0.000	0.000	0.000	(2.249)
(26)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.176)	(1.551)	0.000	0.000	0.000	0.000	(2.210)
(27)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.193)	(1.551)	0.000	0.000	0.000	0.000	(2.227)
(28)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(29)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(30)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(31)	**2004**	**(5.792)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.636)**	**(18.771)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.199)**
(32)	2005	**(5.789)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(2.960)	(18.612)	0.000	0.000	0.000	0.000	(27.361)
(33)	2006	(0.016)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(1.727)	(15.510)	0.000	0.000	0.000	0.000	(17.253)
(34)	2007	(0.013)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.013)
(35)	2008	(0.010)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.010)
(36)	2009	(0.007)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.007)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes operating expense charges.
(17) Sum of columns (2) through (16).

Reconciliation Adjustment

Narragansett Electric Company (22.4%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

	(1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Other (16)	TOTAL (17)
(1)	**1998**	**(0.475)**	**(10.718)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.077)**	**0.000**	**0.000**	**(0.139)**	**0.000**	**0.000**	**0.063**	**(11.346)**
(2)	**1999**	**(1.335)**	**0.000**	**(0.448)**	**(0.233)**	**(0.493)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.133)**	**(0.123)**	**0.034**	**(2.731)**
(3)	**2000**	**(1.312)**	**0.000**	**0.055**	**0.000**	**0.002**	**0.000**	**0.000**	**0.000**	**(0.254)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(1.510)**
(4)	**2001**	**(1.301)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.093)**	**(0.291)**	**(2.153)**	**(0.009)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(3.847)**
(5)	**2002**	**(1.300)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.017**	**(0.134)**	**(0.693)**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.109)**
(6)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.025)	(0.343)	0.000	0.000	0.000	0.000	(0.475)
(7)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.020)	(0.347)	0.000	0.000	0.000	0.000	(0.475)
(8)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.084)	(0.348)	0.000	0.000	0.000	0.000	(0.540)
(9)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.347)	0.000	0.000	0.000	0.000	(0.497)
(10)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.024)	(0.348)	0.000	0.000	0.000	0.000	(0.480)
(11)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.028)	(0.348)	0.000	0.000	0.000	0.000	(0.484)
(12)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.031)	(0.348)	0.000	0.000	0.000	0.000	(0.487)
(13)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.026)	(0.348)	0.000	0.000	0.000	0.000	(0.482)
(14)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.034)	(0.348)	0.000	0.000	0.000	0.000	(0.490)
(15)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.022)	(0.348)	0.000	0.000	0.000	0.000	(0.478)
(16)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.348)	0.000	0.000	0.000	0.000	(0.498)
(17)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.188)	(0.395)	0.000	0.000	0.000	0.000	(0.691)
(18)	**2003**	**(1.299)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.567)**	**(4.213)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.079)**
(19)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.041)	(0.348)	0.000	0.000	0.000	0.000	(0.497)
(20)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.494)
(21)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.091)	(0.348)	0.000	0.000	0.000	0.000	(0.547)
(22)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.434)	0.000	0.000	0.000	0.000	(0.586)
(23)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.037)	(0.296)	0.000	0.000	0.000	0.000	(0.441)
(24)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(25)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.048)	(0.348)	0.000	0.000	0.000	0.000	(0.504)
(26)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.495)
(27)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(28)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(29)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(30)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(31)	**2004**	**(1.298)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.591)**	**(4.207)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.095)**
(32)	2005	**(1.297)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.663)	(4.171)	0.000	0.000	0.000	0.000	(6.132)
(33)	2006	(0.004)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.387)	(3.476)	0.000	0.000	0.000	0.000	(3.866)
(34)	2007	(0.003)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.003)
(35)	2008	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)
(36)	2009	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes Narragansett Electric's 22.4% share of operating expense charges.
(17) Sum of columns (2) through (16).

The Standard Offer Auction
Proposed Design

A. Administrative Process and Time Line

The Standard Offer Auction (the "Auction") will be administered and conducted via a common process and time line for all distribution companies. Bids will be submitted and evaluated through a Request for Proposal process. The principal steps and approximate timing of the Auction are outlined below. Narragansett reserves its right to defer the auction or adjust the following schedule to coordinate with the Standard Offer Auction of its affiliate, Massachusetts Electric Company. Massachusetts Electric Company has issued a request for qualification on April 3, 1997 that provides additional details on the Standard Offer Auction. Both Massachusetts Electric Company and Narragansett reserve their right to modify the terms and the timing of the Standard Offer Auction.

<u>March 1997</u> - <u>Preliminary RFP Issued</u>

The Preliminary RFP will detail all of the major elements, requirements and commercial terms and conditions of the final RFP that will be issued in August. Its purpose is to give potential bidders the necessary information to determine whether they intend to participate in the Auction. Specific pre-bid qualifications will be established including an audited statement of financial qualifications and other relevant information to ascertain a bidder's ability to perform. Neither the terms of the Preliminary RFP nor Final RFP shall require a bidder to hold title to the power needed to fulfill its obligations under its bid.

Pre-bid applications including required bidder qualification information are due by (a date to be specified in the Preliminary RFP) along with a modest non-refundable administration fee of $1,000.

<u>July 1997</u> - <u>List of Qualified Bidders Submitted to the Rhode Island Commission</u> (for informational purposes)

<u>August 1997</u> - <u>Final RFP Issued</u> (including a standard contract)

<u>September 1997</u> - <u>Bids Due</u>

Bids would be accepted only from pre-qualified bidders and must include a deposit of $1,000 for each GWH the bidder proposes to supply over the duration of the Standard Offer. *For example, if a bidder proposed to supply 500 GWH per year for twelve years, its deposit would total $6,000,000 ($1,000 x 500 GWH x 12 yrs).* This deposit is refunded in the event that a bidder is not selected. If [redacted] [redacted] [redacted]

successful, at the bidder's election, the deposit can either be refunded or applied toward the performance bond (described below).

October 1997 - Winning Bidders Selected

Contracts are expected to be executed between bidders and the distribution companies and become effective upon the bidders (now considered "suppliers" in this description) establishing a "performance bond" in the amount of $10,000 per GWH to be supplied under the Standard Offer. The performance bond would be returned to the supplier upon completion of its contractual obligations.

B. Important Auction Rules and Conditions

1. Minimum Bid Elements. In order to conduct a fair and effective Auction, all bids from pre-qualified bidders must include a "Percentage Discount Off the Standard Offer" (the "Discount") and the "Amount of Energy to be Delivered" as described and applied below. These two elements will be the only criteria by which winning bidders are chosen. All bids from pre-qualified bidders will otherwise be considered to be equivalent.

2. The Auction Procedures. Narragansett shall implement the following auction procedures for determining the suppliers of Standard Offer Service:

   a. Twelve Year Flat Discount Auction[1]. This is a single, constant discount to be in effect for all twelve years of the Standard Offer, expressed as a percentage greater than 0%, with larger discounts being viewed more favorably. Winning bidders are to be paid based upon the next highest Discount bid whether determined by the Twelve Year Flat Discount Auction or by the lowest discount bid in the next best Alternative Individual Auction Increment, discussed below (a second price or Vickery auction).[2] The bids in this auction shall be sealed until the Alternative Individual Year Auction set forth below is completed.

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[1] NEP and Narragansett shall have the right in their sole discretion to shorten the period of standard offer service to December 31, 2004, if Narragansett no longer has the obligation under the Rhode Island URA to extend standard offer service through 2009.

[2] For example, if the best four winning bids (out of 10 submitted) met the distribution company's expected demand at Discounts of 12.5%, 10%, 9% and 7% respectively, the first winning bidder would receive a discount of 10%, the second winning bidder 9%, the third 7%, and the fourth would receive the Discount bid by the first losing bidder (who bid 6.5%).

b. <u>Alternative Individual Year Auction ("Alternative Auction")</u>. This Alternative Auction shall take place immediately following the Twelve Year Flat Discount Auction. Bidders will be required to bid separately for each year, and unlike the Twelve Year Flat Discount Auction, a bid for any single year may not be conditioned on success in any other year. Thus, the Alternative Auction shall allow bidders to specify different discounts in different years. Bid amounts must be in annual increments of 150 gigawatthours of energy, which will be delivered as specified below. Prices in the Alternative Auction shall be open to other bidders, but the identity of the bidders associated with the prices will not be identified. The Alternative Auction will continue for multiple rounds until the next bid fails to improve the discount offered in the prior bid by one percent.

Following completion of the bidding, Narragansett shall rank the bids for each individual year, with larger discounts viewed more favorably, and shall identify the best bids in each year that would fill a 150 gigawatthour increment covering all twelve years of the purchase period. Narragansett will then repeat the process for as many increments as possible until the bids no longer cover all twelve years in the period.

c. <u>Selection of Suppliers from Both Auctions</u>. The increments from the Alternative Individual Year Auction will then be compared to the Twelve Year Flat Discount Auction by assigning the Alternative Individual Auction Increment with the lowest discount bid in any single year of the increment. In the event of ties, the earliest, highest discount shall have priority. Suppliers in the Alternative Individual Year Auction shall be held to their bids, unlike the second price or Vickery auction used in the Twelve Year Flat Discount Auction.

NEP shall be allowed, but not required, to bid in the Alternative Individual Year Auction.

3. <u>Payment by Distribution Company</u>. The distribution company is responsible for paying suppliers at the following electric delivery rates, reduced by the applicable Discount, for all energy the supplier delivers (less losses) in the respective year. These rates are flat annual values and do not include a demand or capacity component and will not be adjusted for seasonal or time of day factors.

<u>Distribution Company Rates</u>

1998	3.2 ¢/KWH
1999	3.5

2000	3.8
2001	3.8
2002	4.2
2003	4.7
2004	5.1
2005	5.5
2006	5.9
2007	6.3
2008	6.7
2009	7.1

For example, if a supplier bid a Discount of 5.5% and delivered 500 GWH to ultimate customers in 1999, that supplier would receive $16,537,500 from the distribution company (3.5¢/kwh x (1-.055) x 500 GWH x 1,000,000 kwh/GWH x .01 $/¢).

A fuel index adjustment mechanism, applied to Customer Rates, may provide additional revenues to suppliers in the event that large, unexpected increases in market oil and gas prices occur. This adjustment is further described below.

4. Amount of Energy to be Delivered ("Delivered Energy"). Bids shall specify a single, constant quantity of energy, expressed in GWH per year, that the bidder commits to supply to the distribution company in each year of the Standard Offer. This amount represents the maximum amount of energy a supplier is responsible to provide to the distribution company annually, as measured at the ultimate customer's meter. For purposes of determining the amount of the bid deposit and performance bond, the total energy to be supplied under the standard offer will be the Delivered Energy value times the number of years the energy will be provided. Suppliers are responsible for all electric delivery losses and any necessary transmission arrangements and costs.

5. Right to Bid a Joint Supply - Prequalified bidders will have the right, subject to any provision of law, to submit joint bids pursuant to which one supplier may provide less than the full amount of Delivered Energy as long as the other suppliers on the joint bid provide the remainder of the Delivered Energy obligation, and the total performance bond is posted and in effect for the twelve years .

6. Higher Discounts Ensure a Right to a Longer Term of Supply - Customers have the right to leave the Standard Offer at any time to receive service in the competitive energy market (subject to minimal notice provisions). As such, the amount of energy required from suppliers under the Standard Offer may likely

decline over time. Supplier(s) who are in the increment with the highest Assigned Discount will have the right to provide energy for the longest period of time. With declining customer load due to departures from Standard Offer service, lower Discount suppliers whose Delivered Energy amount exceeds the distribution company's needs will have their Delivered Energy amounts reduced and Standard Offer supply contracts ultimately terminated.

7. Load Responsibility and Allocation - Suppliers are responsible for a percentage of the distribution company's Standard Offer real-time customer energy demand (minute by minute, hour by hour, day by day). This includes changes in customer demand for any reason, including but not limited to, seasonal factors, normal daily load patterns, increased usage, demand side management activities, extremes in weather, etc. The only exception is for the loss of Standard Offer customers as described in the section immediately above. Responsibility is allocated to a supplier based on its Delivered Energy bid divided by the estimated total annual Standard Offer energy demand of the distribution company.

8. Responsibility for Electric Delivery Losses - Suppliers will provide all losses, in kilowatts and kilowatthours, from the supplier's generation sources to the customer meter.

C. Standard Offer Customer Rates and Customer Rights

Customers who elect Standard Offer service by choice or inaction will pay predetermined, flat rates ("Customer Rates") for energy consumed. At any time during the Standard Offer customers have the right to leave Standard Offer service and receive energy from another supplier in the marketplace. In addition, residential and C-2 customers have a limited right to return to standard offer service in the first year after the retail access date.

Customer Rates are subject to upward adjustment in the event of substantial increases in the market prices of No. 6 residual fuel oil (1% sulphur) and natural gas after 1999, as described in the following section. If invoked, prices would change as a function of the amount by which market fuel prices exceed the predetermined price "trigger" levels. These triggers have been set to allow a large dead-band in which no increases to Customer Rates would apply.

D. Standard Offer Fuel Index

The Customer Rate in effect for a given billing month is multiplied by a "Fuel Adjustment" that is set equal to 1.0 and thus has no impact on Customer Rates unless the

"Market Gas Price" plus "Market Oil Price" for the billing month exceeds the "Fuel Trigger Point" then in effect, where:

Market Gas Price is the average of the values of "Gas Index" for the most recent available twelve months, where:

Gas Index is the average of the daily settlement prices for the last three days that the NYMEX Contract (as defined below) for the month of delivery trades as reported in the "Wall Street Journal", expressed in dollars per MMBtu. NYMEX Contract shall mean the New York Mercantile Exchange Natural Gas Futures Contract as approved by the Commodity Futures Trading Commission for the purchase and sale of natural gas at Henry Hub;

Market Oil Price is the average of the values of "Oil Index" for the most recent available twelve months, where:

Oil Index is the average for the month of the daily low quotations for cargo delivery of 1.0% sulphur No. 6 residual fuel oil into New York harbor, as reported in "Platt's Oilgram U.S. Marketscan" in dollars per barrel and converted to dollars per MMBtu by dividing by 6.3; and

If the indices referred to above should become obsolete or no longer suitable, the distribution company shall file alternate indices with the Rhode Island Commission.

Fuel Trigger Point is the following amounts, expressed in dollars per MMBtu, applicable for all months in the specified calendar year:

2000	$5.35/MMBtu
2001	$5.35
2002	$6.09
2003	$7.01
2004	$7.74

Narragansett shall file Fuel Trigger Points for the years following 2004 with the Rhode Island Commission prior to the date of the Auction.

In the event that the Fuel Trigger Point is exceeded, the Fuel Adjustment value for the billing month is determined based according to the following formula:

Fuel = (Market Gas Price + $.60/MMBtu) + (Market Oil Price + $.04/MMBtu)

Adjustment Fuel Trigger Point + \$.60 + \$.04/MMBtu

Where:

Market Gas Price, Market Oil Price and Fuel Trigger Point are as defined above. The values of \$.60 and \$.04/MMBtu represent for gas and oil respectively, estimated basis differentials or market costs of transportation from the point where the index is calculated to a proxy power plant in the New England market.

For example, if at a point in the year 2002 the Market Gas Price and Market Oil Price total \$6.50 (\$3.50/MMBtu plus \$3.00/MMBtu respectively), the Fuel Trigger Point of 6.09 would be exceeded. In this case the Fuel Adjustment value would be:

$$\frac{(\$3.50 + \$.60/MMBtu) + (\$3.00 + \$.04/MMBtu)}{\$6.09 + \$.60 + \$.04/MMBtu} = 1.0609$$

The Customer Rate paid to the distribution company is increased by this Fuel Adjustment factor for the billing month, becoming 4.4548¢/KWH (4.2 x 1.0609).

In subsequent months the same comparisons are made and, if applicable, a Fuel Adjustment determined.

Incremental revenues received by the distribution company as the result of a Fuel Adjustment would be fully allocated to Standard Offer suppliers in proportion to the Standard Offer energy provided by a supplier to the distribution company in the applicable billing month.

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Company	)))

SETTLEMENT

WHEREAS, this Settlement ("Settlement") is entered into by and among the Rhode Island Division of Public Utilities and Carriers, the Rhode Island Public Utilities Commission ("RIPUC"), Narragansett Electric Company ("Narragansett Electric"), and New England Power Company ("NEP") (together, the "Parties") with regard to NEP's Reconciliation of Contract Termination Charges ("CTC") to Narragansett Electric ("1999 Reconciliation Report") filed on December 1, 1999 with the RIPUC;

WHEREAS, the Parties engaged in extensive discovery and negotiation of issues related to the 1999 Reconciliation Report pursuant to the informal dispute resolution process set forth in Section 3.5 of the NEP/Narragansett Electric restructuring settlement approved by the Federal Energy Regulatory Commission ("Commission") in Docket No. ER97-680-000 and ER98-6-000 ("Restructuring Settlement");

WHEREAS, pursuant to such discovery and negotiations, NEP and Narragansett Electric have made adjustments to the 1999 Reconciliation Report in its 2000 Reconciliation Report as described below;

NOW, THEREFORE, in consideration of the promises and covenants hereinafter contained, the Parties hereby agree as follows:

(1) In its 2000 Reconciliation Report, NEP modified its return calculation for the month of September 1998 to calculate interest beginning on September 1, 1998 on the $10.7 million lump sum credit in accordance with a settlement dated September 10, 1999 and accepted by FERC in Docket

No. ER99-4568-000 (Nov. 9, 1999) associated with NEP's 1998 CTC Reconciliation Filing. NEP also included a monthly return calculation for September through December 1998, as it previously had been incorrectly omitted. (Compare lines (1) – (5), Column (6) of NEP's 1999 and 2000 Reconciliation Reports).

(2) This Settlement resolves all issues presented by the 1999 Reconciliation Report and no further adjustments are warranted unless new facts and circumstances that occurred during 1999 are discovered or new developments occur that bring 1999 facts, circumstances, costs or revenues into issue.

(3) The making of this Agreement shall not be deemed in any respect to constitute an admission by any party that any allegation or contention in this proceeding is true and valid.

(4) The Commission's approval of this Agreement shall not constitute approval of, or precedent regarding any principle or issue in this proceeding.

(5) The discussions which have produced this Agreement have been conducted on the explicit understanding, pursuant to Rule 602(e) of the Commission's Rules of Practice and Procedure, that all offers of settlement and discussions relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussions and are not to be used in any manner in connection with these or any other proceedings.

(6) This Agreement is expressly conditioned upon the Commission's acceptance of all provisions hereof, without change or condition, and in

the event the Commission does not by order accept it in its entirety, it shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or be used for any other purpose, and each of its provisions shall be deemed to be null and void.

(7) Any number of counterparts of this Agreement may be executed, and each shall have the same force and effect as an original instrument, and as if all the Parties to all the counterparts had signed the same instrument.

Respectfully submitted,

NATIONAL GRID USA SERVICE COMPANY, INC.
NARRAGANSETT ELECTRIC COMPANY
By its attorney,

Thomas G. Robinson
Deputy General Counsel
25 Research Drive
Westborough, MA 01582

DIVISION OF PUBLIC UTILITIES AND CARRIERS
By its attorney,

Paul Roberti, Assistant Attorney General
150 South Main Street
Providence, Rhode Island 02903

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By its attorney,

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Deputy General Counsel
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DIVISION OF PUBLIC UTILITIES AND CARRIERS
By its attorney,

Paul Roberti, Assistant Attorney General
150 South Main Street
Providence, Rhode Island 02903

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Elia Germani

Elia Germani, Chairman
89 Jefferson Blvd.
Warwick, Rhode Island 02888

June
Dated: ~~May~~ 5, 2001

Appendix 1

MONTAUP ELECTRIC COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH
NEWPORT ELECTRIC CORPORATION UNDER
FERC ELECTRIC TARIFF, FIRST REVISED VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT
TERMINATION CHARGES

1.1 The Fixed Component of the Contract Termination Charge shall include Newport Electric Corporation's ("Newport") 11.85 percent allocated share of Montaup's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the following plant balances and regulatory assets:

(a) Plant balances shall include unrecovered net book value as shown on Schedule 1, Page 4, Column (7), of the following Montaup generation-related investments as of December 31, 1997,[1/] excluding any capital additions made after December 31, 1995:

(i) Somerset Unit 6, Jet 1 and Jet 2 including general plant allocated to generation;
(ii) Montaup's ownership Share of Canal Unit 2, including capital additions past December 31, 1995, but committed prior to that date;
(iii) Montaup's and Newport's ownership share of Wyman Unit 4;
(iv) Montaup's ownership share of Millstone Unit 3;
(v) Montaup's ownership share of Seabrook Unit 1;
(vi) Montaup's Entitlements in the Vermont Yankee Unit, including the balances for materials and supplies;

[1/]The figures shown on Schedule 1, Page 4, Column (7) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

(vii) Newport's generation related investment in the Diesel Units at Jepson and Eldred;
(viii) Step-up transformers at Montaup generating units which are excluded from Montaup's transmission rates;
(ix) Montaup's non-utility property; and
(x) Generation-related property held for future use including net investment in Somerset Unit 5, through November 1, 1997, per settlement agreement in Docket ER94-1062-000.

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 5, Column (2), as of December 31, 1997[2/]:

(i) FAS 109;
(ii) Net pension liability/(asset) of Montaup and allocated to Montaup by affiliates to the extent that they exceed 5% of the greater of the total pension benefits obligation or the fair market value of plan assets;
(iii) Unamortized deferred FAS 106 costs;
(iv) Unamortized deferred dredging costs; and
(v) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison Company.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.34 percent based on a combined state and federal income tax rate of 39.225 percent, and Montaup's 1995 year-end capital structure as shown in Schedule 1, Page 14, Column (8), including a return on common equity of 9.2 percent for the period prior to the completion of the initial divestiture process for Montaup's non-nuclear generating facilities ("Divestiture Date")[3/], and sufficient to provide an overall pretax return of 13.09 percent including a

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[2/]The figures shown on Schedule 1, Page 5, Column (2) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

[3/]If Montaup sells its non-nuclear generating facilities in more than one transaction, the rights and obligations associated with the divestiture shall be allocated among the transactions using appropriate allocators. In the case of return, the allocator shall be based on the net book value of the sold facility or facilities to total net book value of the non-nuclear generating facilities in Section 1.1.1(a). This percentage allocation shall be applied to the total of plant, regulatory asset balances, and deferred tax balances as set forth below.

return on common equity of 11.4 percent for the period after the Divestiture Date,[4] multiplied by the average of the beginning and ending balances in each calendar year beginning in 1998 of the sum of the following:

(a) Unrecovered net book value of Montaup's generation investments as defined under 1.1.1(a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1(b) above, less

(c) Deferred Taxes as shown in Schedule 1, Page 13, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of Montaup's generation investment, plus
(ii) the unrecovered net book value of generation-related regulatory assets, less
(iii) the unrecovered balance of generation investment for tax purposes, less
(iv) the unrecovered balance of generation-related regulatory assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition

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[4] The difference between the 11.34 percent and 13.09 percent returns as applied to unamortized balances prior to the Divestiture Date shall be recovered, if divestiture occurs, through an offset to the Residual Value Credit. Effective with the merger of Montaup into the New England Power Company (NEP) on May 1, 2000, the overall pre-tax return is changed from the 13.09 percent to the return allowed in NEP's contract termination charge formula or 12.16%. The 11.34 percent, 13.09 percent and 12.16 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. Notwithstanding the above, an equity return of 9.2% will be applied to Montaup's equity investment in the Ocean States Power facility for purposes of estimating Contract Termination Charges under the Amendment.

Obligation of Montaup and allocated to Montaup by its affiliates[5]; and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates. Following the Divestiture Date, these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) For each month that the Contract Termination Date is delayed beyond January 1, 1998, Montaup shall adjust the Reconciliation Account in the Variable Component of the Contract Termination Charge by an amount equal to the difference between the depreciation and amortization expense authorized under the M-14 rate and the depreciation and amortization under Section 1.1.1, together with the associated return computed in accordance with Section 1.1.2 of this Appendix, multiplied by Newport's 11.85 percent allocated share. An exhibit showing the difference between

[5] Any FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

depreciation and amortization under the M-14 rate and the Contract Termination Charge is included in Schedule 2.

(b) Following the Divestiture Date and at the time of implementing the Residual Value Credit, Montaup shall reconcile the balances in Sections 1.1.1 and 1.1.3 for Newport's 11.85 percent allocated share of (i) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 106 obligation; and (ii) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 87 obligation, but the gains or losses associated with FAS 87 shall be recognized only to the extent that they exceed five percent of the greater of total pension benefits obligation or fair market value of plan assets. Montaup shall fund the FAS 106 and FAS 87 obligations under this Section and Section 1.2.2(f) as rapidly as permitted by the tax law up to the level of revenues collected for this purpose.[6/] Any revenues associated with these obligations that cannot be immediately funded shall be put into a separate account on the books to be reserved with the return specified in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS 106 and FAS 87, whether positive or negative, shall be subtracted from or

[6/]Montaup's post-divestiture FAS 106 or FAS 87 gains or losses recognized on Montaup's books shall be fully reflected in rates to customers and shall neither be retained nor borne by Montaup. Montaup shall propose an allocation of these post-divestiture gains or losses between customers paying Contract Termination Charges and transmission customers.

added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, Montaup shall reconcile the balances for Newport's 11.85 percent allocated share of (i) the FAS 109 regulatory asset; and (ii) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the Residual Value Credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the sale and December 31, 2009.

(c) Montaup has agreed to divest its generating business within six months after the later of the Retail Access Date as defined in the Settlement filed in Docket ER97-3127-000 or the receipt of all governmental approvals and other consents necessary for the divestiture. Within three months after the completion of divestiture or the sale of any property,[7] the cost of which is included in the Contract Termination Charge, Montaup shall

[7]Proceeds, if any, from Montaup's future leases of nuclear entitlements will also be flowed through the Residual Value Credit if such proceeds can be definitively calculated at the time the Residual Value Credit is determined. The proceeds from leases determined after the Residual Value Credit is set will be flowed through the Reconciliation Account as received.

implement a Residual Value Credit as a direct offset to the Contract Termination Charges authorized under this Amendment. The Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. Proceeds from the divestiture which are realized after the full implementation of the Residual Value Credit will be reflected in the variable component of the CTC as hereinafter described. The Residual Value Credit to Newport shall be calculated as follows:

(i) Newport's 11.85 percent allocated share of Total Proceeds[8] equal to the sale price and other consideration received by Montaup, less

(ii) The revenues lost or gained by Montaup between July 1, 1997 and the Divestiture Date measured by the difference between the revenues excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 had it continued to make the sales to Newport under Tariff 1 and the revenues, excluding transmission revenues and Contract Termination

[8] As part of the terms of the Divestiture, Montaup shall require the buyer of the facility to pay Montaup the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for Montaup's non-nuclear facilities are excluded from the plant balances under Section 1.1.1, and shall be excluded from the calculation of the Residual Value Credit. In addition, the Buyer may assume other obligations that are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

Charge revenues, that it actually collected from sales to Newport's customers during the period, together with a credit for Newport's share of the revenue from sales at no less than market prices made by Montaup to third parties during the period, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of kilowatthours delivered by Newport during the period between the July 1, 1997 and the Divestiture Date, less

(iii) Newport's 11.85 percent allocated share of capital investments demonstrated to be prudently incurred after December 31, 1995, excluded from the plant balances in Section 1.1.1 (a) above,[2] less

(iv) Newport's 11.85 percent allocated share of reasonable transaction costs associated with the divestiture including the cost of necessary refinancings, repurchases, and retirements of securities occurring after May 1, 1997, less

(v) Employee severance and retraining costs pursuant to Section 1.2.2(f).

The Net Proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax

[2] Montaup's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities during the period January 1, 1996 through May 31, 1997 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. Montaup may include additional projects, if any, at the time of the calculation of the Residual Value Credit, subject to the dispute resolution procedures under Section 3.5 of the Agreement.

impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Contract Termination Date, or (ii) the Residual Value Credit exceeds the Contract Termination Charge in any given year. If for any reason, generation assets which were not sold at the Divestiture Date and therefore were not in the Residual Value Credit but remained in the Contract Termination Charge, are sold at a later date, the proceeds of such a sale will be amortized, with a return as specified in Section 1.1.2, over the remaining fixed component recovery period or over a five year period, whichever period is greater, and credited to the Reconciliation Account as received.

(d) Effective with refinancings, repurchases, and retirements of securities prior to May 1, 2000 relating to assets being recovered through Contract Termination Charge, Montaup shall flow through the Reconciliation Account the annual effects associated with any differences between the 13.09 percent overall pre-tax return and the actual pre-tax return, calculated using an 11.4 percent return on common equity, attributable to changes in the cost of long-term debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 13.09 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 13.09 percent overall pre-tax return shall be adjusted to include

Montaup's actual cost of long-term debt and preferred stock using an 11.40 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

Securitization will be implemented only if it would produce net savings to customers after taking into account all transaction costs including call provisions and prepayments, if applicable. Notwithstanding the above, savings from securitization, (pursuant to the terms of a qualified rate order), will be reflected in the Contract Termination Charge.

Any and all financing savings associated with refinancing related to divestiture and following the implementation of the Residual Value Credit, shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in Montaup's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by FERC, however, they shall not also be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Newport's allocated share of the items specified in Section 1.2.2, below adjusted for the Reconciliation Account discussed in Section 1.2.1.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract

Termination Charge Payments by Newport and Newport's allocated share of the estimated variable costs listed in Section 1.2.2 below and actual Contract Termination Charge payments by Newport and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from Montaup to Newport. The Reconciliation Account shall also include the adjustments under Sections 1.1.2, note 4, 1.1.4(a) and 1.1.4(d) above. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

Montaup shall return or collect Newport's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Newport. The balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust Montaup's Base Contract Termination Charges for the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 2.8 cents per kilowatthour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Base Contract Termination Charge.

1.2.2 Newport's 11.85 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1 at page 3. The difference between Newport's percent allocated share of the actual variable costs incurred by Montaup and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) Nuclear Decommissioning and Other Post Shutdown Costs shown on Schedule 1, Pages 6 and 7, shall include: (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1(a) (iv), (v), and (vi) above, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds; (ii) all other reasonable post shutdown costs associated with Montaup's entitlements in the units listed in Section 1.1.1(a), (iv), (v), and (vi) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with Yankee Rowe, Connecticut Yankee and Maine Yankee shown on Schedule 1, page 7. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to Montaup's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, any over collection will be refunded to Newport in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

Montaup's share of the Book Value of the Actual Nuclear Core at Shutdown or time of sale, which Montaup has not previously recovered through sales or lease proceeds and the Book Value of Materials and Supply at Shutdown or time of sale, which have not been addressed by other recovery mechanisms, will be recovered with a carrying charge in equal amounts over three years at a pre-tax return provided for in Section 1.1.2.

(b) Power Contract Payments will be (i) all payments by Montaup for Long-Term Power Supply Contracts less the market value realized from the resale of electricity purchased under the contracts into the wholesale market, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts, plus (iv) the Power Contract Buyout Incentive realized.

(i) Long-Term Power Supply Contracts will be the power supply contracts listed below which were in place as of December 31, 1995, between Montaup and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

(1) Ocean State Power I and II
(2) Canal 1, including transmission wheeling, rental and support payments
(3) Northeast Energy Associates, including transmission wheeling payments
(4) Potter 2, including transmission wheeling payments
(5) Cleary 9

(6) McNeil, including transmission wheeling payments
(7) Newport Hydro, Inc., including transmission wheeling payments
(8) Hydro Quebec, including AC and DC facilities support payments
(9) Pilgrim, including transmission wheeling, rental and support payments
(10) Bear Swamp Hydro
(11) Green Mountain Power Peakers, including transmission wheeling payments

(ii) Economic Buyout Payments will be all reasonable payments agreed to by Montaup after May 1, 1997 associated with the sale, assignment, disposition or buy down of the Long-Term Power Supply Contracts. Economic Buyout Payments shall be recovered as incurred to the extent that current recovery does not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

For purposes of calculating above market payments in (b)(i) and economic buyout payments in (b)(ii), associated with the long term supply contracts with Ocean State Power I and II, Montaup's total obligation under the contracts will be based on a return on equity of 9.2%.

(iii) Credit for Unit Sales Contracts will be all unit sales contracts entered into by Montaup as of December 31, 1995, for sales from (i) Canal Unit 2 if it is not otherwise subject to market valuation and (ii) Contract Demands to non-affiliates, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9).

(iv) Power Contract Buyout Incentive will be the sum of: (a) the Power Contract Buyout Incentive associated with Canal 2 Divestiture calculated in accordance with Schedule 3, pages 2 and 3; and (b) the Power Contract Buyout Incentive Independent of Divestiture which shall represent 10% of the savings realized by customers as the result of the sale, assignment, disposition or buy down of its power supply contracts occurring outside of the divestiture process. The Power Contract Buyout Incentive Independent of Divestiture shall be determined at the time of the sale, assignment, disposition or buy down. The Buyout Incentive for the Ocean State Power units will be calculated in accordance with Page 4 of Schedule 3. The Total Power Contract Buyout Incentive shall not exceed $ 1.6 million, stated on a present value basis upon the divestiture using a discount rate equal to the actual pre-tax return in place following completion of post divestiture refinancing as determined under Section 1.1.4(d). Montaup shall document the level of the Power Contract Buyout Incentive in a report, and the amount of the Power Contract Buyout Incentive shall be subject to the dispute resolution procedures set forth under Section 3.5 of the Stipulation and Agreement. The Power Contract Buyout Incentive Associated with Canal 2 Divestiture will be recovered in equal increments over the period from the divestiture through December 31, 2009, with appropriate adjustments for the time value of money, and the Power Contract Buyout Incentive Independent of Divestiture will be recovered in equal increments over the remaining term of the related purchased power contract, with appropriate adjustments for the time value of money.

(c) Above Market Fuel Transportation as shown in Schedule 1, Page 15, Column 10 will be Montaup's continuing long-term payment obligations associated with Capacity Payments to Algonquin Natural Gas Pipeline for Canal 2 less the market value of that capacity. The Market Value of Capacity Payments to Algonquin Natural Gas Pipelines will equal the actual proceeds associated with the sale or assignment or termination of contractual obligations. For the purposes of calculating the Contract Termination Charges, prior to the date that Montaup's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the

Market Value of Capacity Payments to Algonquin Natural Gas Pipeline shall be deemed to equal the savings associated with actual unit operation on natural gas compared to the unit's avoided operation on oil at prevailing market prices. For illustrative purposes, the amounts shown on page 15 of Schedule 1 reflect a market value which is 50 percent of the capacity payments.

(d) Transmission wheeling, rental and support charges as shown in Schedule 1, Page 3, associated with the transmission of electricity from Montaup's entitlements in Seabrook Unit 1, Millstone Unit 3, Wyman Unit 4, Canal Unit 2, Vermont Yankee, which units are located off of Montaup's transmission system. These wheeling and support payments shall include only costs that are excluded from recovery under Montaup's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of the unit.

(e) Payments in Lieu of Property Taxes will include all reasonable costs incurred by Montaup or its affiliates associated with payments in lieu of property taxes to the cities and towns in which Montaup owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciling Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining Costs as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by Montaup or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of Montaup's Tariff No 1, including, but not limited to early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. The recovery of costs under this paragraph incurred by Montaup or its affiliates are limited to $15 million. [10/] In the event that the actual costs incurred under this paragraph are less than $15 million, excluding costs found by FERC to be recoverable in Montaup's transmission rates, Montaup shall flow back the difference to customers in the Reconciliation Account. The procedure established in this paragraph shall be the exclusive method for recovering the costs under this paragraph, and, except in the event of legislation changing required benefits, neither Montaup nor its affiliates shall be able to recover more than $15 million, subject to the Canal 2 adjustment, for these costs. Thus, for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the

[10/] The parties agree that $11.8 million will be reserved for Montaup and EUASC employees and estimate that $3.2 million will be reserved for Canal 2 and paid by the buyer of Canal 2. The Canal 2 figure may be adjusted when actual figures are available from Canal Electric.

event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shall include all damages, costs, or recoveries associated with Montaup's generating business which accrued prior to the date of divestiture and which were not: (i) included in the reserves for generation related, uninsured claims other than claims associated with Environmental Response Costs as of May 21, 1994, plus annual additions to the reserves for uninsured claims in Montaup's M-14 rate, less actual payments out of the reserve for generation related claims during the period from May 21, 1994 through the Contract Termination Date; (ii) assigned to Montaup's successor in interest; (iii) recovered from Montaup's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, Damages, Costs, or Net Recoveries from claims are assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of Montaup's minority ownership share of the Seabrook, Millstone #3, Maine Yankee and Vermont Yankee Nuclear Units ("PBR

Nuclear Units") that are not otherwise reflected in the Residual Value Credit. If Montaup is unable to sell, lease, assign, or otherwise dispose of its PBR Nuclear Units on the terms set forth in the Stipulation and Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and post-1995 capital additions on a cost of service basis,[11/] associated with Montaup's PBR Nuclear Units that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units or entitlements that are not otherwise reflected in contract termination charges. The Performance Based Rate shall apply for the period from the Contract Termination Date to the date that Montaup either sells, leases, assigns or otherwise disposes of the PBR Nuclear Units or to the date such units are shutdown. Within six months prior to implementing the Performance Based Rate, Montaup will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potential credit for nonperformance of $250,000. Such sales, if any, shall not be made directly to Newport's retail customers, however, Montaup shall retain the right to use its minority shares of the PBR Nuclear Units to fulfill its backstop

[11/]In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Newport relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Newport relating to deposits and wastes occurring prior to the Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located within the switchyards for which Montaup will retain a permanent easement on parcels that are otherwise being divested if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) proceeds from insurance companies related to Environmental Response Costs; (ii) proceeds from the sale of properties purchased under paragraph (iii); and (iii) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of Montaup to governmental authorities or third parties other than the buyer or buyers of Montaup generating facilities under any environmental law including those referenced in paragraph (iv).

(j) Amortization of generation-related deferred investment tax credits through December 31, 2009. These amounts are shown on Schedule 1, Page 15 of 15, Column 10, effective April 1, 1999.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO NEWPORT ELECTRIC COMPANY

Schedule 1
Page 1 of 15

YEAR	EST. NEC MWH SALES	SHARE OF FIXED COMPONENT $ IN 000	SHARE OF FIXED COMPONENT CENTS/KWH	SHARE OF VAR. COMPONENT $ IN 000	SHARE OF VAR. COMPONENT CENTS/KWH	SHARE OF TOTAL TERM CHARGE $ IN 000	BASE CONTRACT TERM CHARGE CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	530,586	6,196	1.17	9,721	1.83	15,918	3.00
PRE RVC '99	134,139	1,666	1.24	2,358	1.76	4,025	3.00
POST RVC '99	402,416	4,154	1.03	4,139	1.03	8,293	2.06
2000	544,130	7,963	1.46	3,107	0.57	11,070	2.03
2001	549,613	3,371	0.61	4,411	0.80	7,782	1.42
2002	555,606	3,018	0.54	5,059	0.91	8,077	1.45
2003	563,367	4,395	0.78	4,838	0.86	9,232	1.64
2004	571,358	4,436	0.78	3,106	0.54	7,542	1.32
2005	580,288	3,741	0.64	3,141	0.54	6,882	1.19
2006	589,480	-4	0.00	5,295	0.90	5,291	0.90
2007	596,369	2,670	0.45	3,623	0.61	6,293	1.06
2008	603,135	2,011	0.33	2,431	0.40	4,441	0.74
2009	609,079	2,907	0.48	2,382	0.39	5,289	0.87
2010	616,061	0	0.00	1,085	0.18	1,085	0.18
2011	622,439	0	0.00	376	0.06	376	0.06
2012	627,545	0	0.00	341	0.05	341	0.05
2013	636,621	0	0.00	306	0.05	306	0.05
2014	643,741	0	0.00	297	0.05	297	0.05
2015	649,276	0	0.00	288	0.04	288	0.04
2016	654,269	0	0.00	280	0.04	280	0.04
2017	661,599	0	0.00	235	0.04	235	0.04
2018	667,717	0	0.00	228	0.03	228	0.03
2019	673,767	0	0.00	221	0.03	221	0.03
2020	680,723	0	0.00	188	0.03	188	0.03
2021	687,311	0	0.00	0	0.00	0	0.00
2022	694,002	0	0.00	0	0.00	0	0.00
2023	700,796	0	0.00	0	0.00	0	0.00
2024	707,697	0	0.00	0	0.00	0	0.00
2025	714,705	0	0.00	0	0.00	0	0.00
2026	721,821	0	0.00	0	0.00	0	0.00
2027	757,912	0	0.00	0	0.00	0	0.00
2028	795,808	0	0.00	0	0.00	0	0.00
2029	835,598	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	3,670	2,381	145	**6,196**	0	6,196
PRE RVC '99	862	769	36	**1,666**	0	1,666
POST RVC '99	2,944	2,327	(26)	**5,245**	(1,091)	4,154
2000	3,355	6,071	(36)	**9,390**	(1,427)	7,963
2001	2,948	1,870	(35)	**4,783**	(1,412)	3,371
2002	2,804	1,659	(33)	**4,430**	(1,412)	3,018
2003	2,605	3,233	(32)	**5,807**	(1,412)	4,395
2004	2,329	3,549	(30)	**5,848**	(1,412)	4,436
2005	2,057	3,125	(29)	**5,154**	(1,412)	3,741
2006	881	554	(27)	**1,408**	(1,412)	-4
2007	721	3,387	(26)	**4,082**	(1,412)	2,670
2008	461	2,986	(24)	**3,423**	(1,412)	2,011
2009	170	4,172	(23)	**4,319**	(1,412)	2,907

COLUMN NOTES:
EACH COLUMN REPRESENTS 11.85% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS POWER TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	949	17,296	8,161	9,134	0	(575)	0	(575)	56	157	0	0	0	0	9,721	0	**9,721**
PRE RVC '99	219	4,328	2,108	2,220	0	(132)	0	(132)	13	38	0	0	0	0	2,358	0	**2,358**
POST RVC '99	843	4,395	0	4,395	0	(257)	0	(257)	(80)	43	0	0	0	0	4,944	(805) **(a)**	**4,139**
2000	1,001	5,984	0	5,984	0	(97)	0	(97)	(61)	23	0	0	0	0	6,851	(3,744) **(b)**	**3,107**
2001	866	6,404	0	6,404	0	0	0	0	(38)	23	0	0	0	0	7,254	(2,844)	**4,411**
2002	773	6,429	0	6,429	0	0	0	0	0	7	0	0	0	0	7,208	(2,149)	**5,059**
2003	708	4,749	0	4,749	0	0	0	0	0	0	0	0	0	0	5,457	(619)	**4,838**
2004	687	4,415	0	4,415	0	0	0	0	0	0	0	0	0	0	5,102	(1,996)	**3,106**
2005	670	4,834	0	4,834	0	0	0	0	0	0	0	0	0	0	5,504	(2,364)	**3,141**
2006	1,020	4,219	0	4,219	0	0	0	0	0	0	0	0	0	0	5,239	56	**5,295**
2007	936	2,687	0	2,687	0	0	0	0	0	0	0	0	0	0	3,623	0	**3,623**
2008	811	1,620	0	1,620	0	0	0	0	0	0	0	0	0	0	2,431	0	**2,431**
2009	723	1,659	0	1,659	0	0	0	0	0	0	0	0	0	0	2,382	0	**2,382**
2010	699	385	0	385	0	0	0	0	0	0	0	0	0	0	1,085	0	**1,085**
2011	0	376	0	376	0	0	0	0	0	0	0	0	0	0	376	0	**376**
2012	0	341	0	341	0	0	0	0	0	0	0	0	0	0	341	0	**341**
2013	0	306	0	306	0	0	0	0	0	0	0	0	0	0	306	0	**306**
2014	0	297	0	297	0	0	0	0	0	0	0	0	0	0	297	0	**297**
2015	0	288	0	288	0	0	0	0	0	0	0	0	0	0	288	0	**288**
2016	0	280	0	280	0	0	0	0	0	0	0	0	0	0	280	0	**280**
2017	0	235	0	235	0	0	0	0	0	0	0	0	0	0	235	0	**235**
2018	0	228	0	228	0	0	0	0	0	0	0	0	0	0	228	0	**228**
2019	0	221	0	221	0	0	0	0	0	0	0	0	0	0	221	0	**221**
2020	0	188	0	188	0	0	0	0	0	0	0	0	0	0	188	0	**188**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 11.85% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)		$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)		UNRECOVERED BALANCE @ APRIL 1, 1999
FOSSIL FUEL UNITS										
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032		23,716	2,158		22,135
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041		35,207	2,917		32,859
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030		1,806	112		1,686
NEWPORT DIESELS	JAMESTOWN/	1961	DIESEL	8.8	1,803		1,499	152		1,399
	PORTSMOUTH, RI/	1978	DIESEL	8.3						
	YARMOUTH, ME	1978	OIL	4.1						
NUCLEAR UNITS										
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705		160,949	4,878		150,217
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749		128,279	4,735		119,726
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786	(a)	3,092	347		2,886
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439	(a)	6,105	667		5,698
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604		604			564
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860		6,449		(b)	6,019
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610		2,610			2,436
			TOTAL	542.6	401,659		370,316	15,966		345,624

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995	BALANCE AS OF DECEMBER 31, 1997	APPLICABLE AMORTIZATION FOR 1996 AND BEYOND		BASIS FOR DEFERRAL	UNRECOVERED BALANCE @ APRIL 1, 1999
	(1)	(2)	(3)		(4)	
FAS 109 - ASSET	39,916	37,466	1,225		FERC RATEMAKING POLICY	34,968
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)		FERC RATEMAKING POLICY	(1,258)
- ITC GROSS-UP	(8,119)	(7,369)	(375)			(6,878)
FAS 106 DEFERRAL	1,313	538	387	(a)	FERC RATEMAKING POLICY	502
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)		FAS 87	(387)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607		FERC RATEMAKING POLICY	9,954
UNAMORTIZED ITC	(12,523)	(11,367)	(578)		FERC RATEMAKING POLICY	(10,609)
DREDGING	424	173	125	(b)	FERC RATEMAKING POLICY	161
TOTAL REG. ASSETS	27,941	28,343	(202)			26,453

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)	534	
DISCOUNT RATE	7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
PRE RVC '99	167	133	300	7,187
POST RVC '99	(124)	(93)	(218)	(1,866) (a)
2000	(187)	(120)	(306)	(1,680)
2001	(187)	(107)	(294)	(1,493)
2002	(187)	(94)	(281)	(1,306)
2003	(187)	(82)	(269)	(1,120)
2004	(187)	(69)	(256)	(933)
2005	(187)	(57)	(243)	(747)
2006	(187)	(44)	(231)	(560)
2007	(187)	(31)	(218)	(373)
2008	(187)	(19)	(206)	(187)
2009	(187)	(6)	(193)	0

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UP
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,731)	(6,161)	(2,480)	(140)	(1,976)	(17,487)
POST RVC '99	(352)	(322)	0	0	0	(674)
2000	0	(511)	0	0	0	(511)
2001	0	(319)	0	0	0	(319)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

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MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	**0**	**1,195**	**68**	**3,944**
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,522
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	**10,660**	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,970	20,094	1,226	**52,290**	0	52,290
PRE RVC '99	7,275	6,487	300	**14,063**	0	14,063
POST RVC '99	24,846	19,637	(218)	**44,266**	(9,209)	35,057
2000	28,310	51,236	(306)	**79,239**	(12,039)	67,200
2001	24,877	15,781	(294)	**40,364**	(11,916)	28,448
2002	23,665	14,003	(281)	**37,387**	(11,916)	25,471
2003	21,983	27,285	(269)	**49,000**	(11,916)	37,084
2004	19,653	29,954	(256)	**49,350**	(11,916)	37,435
2005	**17,359**	**26,374**	(243)	**43,489**	(11,916)	31,574
2006	7,437	4,674	(231)	**11,880**	(11,916)	-36
2007	6,083	28,586	(218)	**34,451**	(11,916)	22,535
2008	3,893	25,195	(206)	**28,883**	(11,916)	16,967
2009	1,434	35,208	(193)	**36,449**	(11,916)	24,533

COLUMN NOTES:
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.1185 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17) /.1185
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENTS
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	351,651	26,914	378,565	64,768	0	64,768	313,797	123,087
PRE RVC '99	345,624	26,453	372,077	63,658	0	63,658	308,419	120,977
POST RVC '99	322,555 (a)	42,062 (a)	364,617 (a)	57,468	0	57,468	307,149	120,479
2000	277,229	36,151	313,381	49,392	0	49,392	263,988	103,549
2001	263,269	34,331	297,600	46,905	0	46,905	250,695	98,335
2002	250,881	32,715	283,596	44,698	0	44,698	238,898	93,708
2003	226,743	29,568	256,311	40,398	0	40,398	215,914	84,692
2004	200,245	26,112	226,358	35,676	0	35,676	190,681	74,795
2005	82,858	10,805	93,663	14,762	0	14,762	78,900	30,949
2006	78,723	10,266	88,989	14,026	0	14,026	74,963	29,404
2007	53,435	6,968	60,403	9,520	0	9,520	50,883	19,959
2008	31,146	4,062	35,208	5,549	0	5,549	29,659	11,634
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)		SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039					
1998	378,565	123,087	255,478	262,258		29,735	1,235	30,970
PRE RVC '99	372,077	120,977	251,100	246,722	(a)	6,993	282	7,275
POST RVC '99	364,617	120,479	244,137	253,044	(b)	24,846	0	24,846
2000	313,381	103,549	209,831	226,984		28,310	0	28,310
2001	297,600	98,335	199,265	204,548		24,877	0	24,877
2002	283,596	93,708	189,889	194,577		23,665	0	23,665
2003	256,311	84,692	171,619	180,754		21,983	0	21,983
2004	226,358	74,795	151,563	161,591		19,653	0	19,653
2005	93,663	30,949	62,714	107,138		**17,359**	0	17,359
2006	88,989	29,404	59,585	61,149		7,437	0	7,437
2007	60,403	19,959	40,444	50,014		6,083	0	6,083
2008	35,208	11,634	23,574	32,009		3,893	0	3,893
2009	0	0	0	11,787		1,434	0	1,434

EECo 12/31/95 **CAPITAL STRUCTURE**				PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000			ATWACC	BTWACC
COM PRE RVC	48.45%	9.20%	(c)	4.46%	7.33%			57.35%	11.00%	(c)	6.31%	10.38%
COM POST RVC		11.40%				5.52%	9.09%					
PFD	5.95%	9.83%		0.58%	0.96%	0.58%	0.96%	0.21%	6.00%		0.01%	0.02%
LTD	45.60%	6.67%		3.04%	3.04%	3.04%	3.04%	42.44%	4.15%		1.76%	1.76%
	100.00%			8.08%	11.338%	9.15%	13.092%	100.00%			8.08%	12.162%
TAX RATE					39.225%		39.225%					39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND ASSOCIATED DEF TAXES OF ($17,792) AND $6,979 FOR ITC LIAB AND, $5,797 AND $1,456 FOR MAINE YANKEE
(c) PER NEP RI FILING.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS: TOTAL OBLIGATION (3)	POWER CONTRACTS: ASSUMED MARKET VALUE (4)	POWER CONTRACTS: NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS: TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS: ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS: NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,522	17,790	18,732	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,902**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(674)	364	0	0	0	0	**41,719**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(511)	193	0	0	0	0	**57,814**
2001	7,304	54,041	0	54,041	0	0	0	0	(319)	193	0	0	0	0	**61,219**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	NEWPORT REVENUE EXCESS/ (SHORTFALL) (6)
2000	544,130	585,428	41,298	2.03	818
2001	549,613	593,463	(43,850)	1.42	645
2002	555,606	592,935	(37,329)	1.45	512
Jan-2003	46,947	58,604	(11,656)	1.64	132
Feb-2003	46,947	54,669	(7,722)	1.64	127
Mar-2003	46,947	52,512	(5,565)	1.64	92
Apr-2003	46,947	47,852	(905)	1.64	15
May-2003	46,947	43,838	3,109	1.64	(50)
Jun-2003	46,947	46,167	780	1.64	(12)
Jul-2003	46,947	52,304	(5,356)	1.64	88
Aug-2003	46,947	58,983	(12,035)	1.64	198
Sep-2003	46,947	58,037	(11,089)	1.64	182
Oct-2003	46,947	50,419	(3,472)	1.64	58
Nov-2003	46,947	45,451	1,497	1.64	(24)
Dec-2003	46,947	53,263	(6,315)	1.64	104
2003	563,367	622,097	(58,730)	1.64	910
Jan-2004	47,613	58,036	(10,423)	1.32	237
Feb-2004	47,613	55,559	(7,946)	1.32	104
Mar-2004	47,613	52,786	(5,172)	1.32	67
Apr-2004	47,613	49,067	(1,454)	1.32	18
May-2004	47,613	44,477	3,137	1.32	(42)
Jun-2004	47,613	46,527	1,087	1.32	(15)
Jul-2004	47,613	53,639	(6,026)	1.32	79
Aug-2004	47,613	56,318	(8,705)	1.32	114
Sep-2004	47,613	58,037	(10,424)	1.32	137
Oct-2004	47,613	**47,613**	0	1.32	(0)
Nov-2004	47,613	**47,613**	0	1.32	(0)
Dec-2004	47,613	**47,613**	0	1.32	(0)
2004	571,358	617,285	(45,927)	1.32	698
Jan-2005	48,357	48,357	0	1.19	0
Feb-2005	48,357	48,357	0	1.19	0
Mar-2005	48,357	48,357	0	1.19	0
Apr-2005	48,357	48,357	0	1.19	0
May-2005	48,357	48,357	0	1.19	0
Jun-2005	48,357	48,357	0	1.19	0
Jul-2005	48,357	48,357	0	1.19	0
Aug-2005	48,357	48,357	0	1.19	0
Sep-2005	48,357	48,357	0	1.19	0
Oct-2005	48,357	48,357	0	1.19	0
Nov-2005	48,357	48,357	0	1.19	0
Dec-2005	48,357	48,357	0	1.19	0
2005	580,288	580,288	0	1.19	0
2006	589,480	589,480	0	0.90	0
2007	596,369	596,369	0	1.06	0
2008	603,135	603,135	0	0.74	0
2009	609,079	609,079	0	0.87	0
2010	616,061	616,061	0	0.18	0
2011	622,439	622,439	0	0.06	0
2012	627,545	627,545	0	0.05	0
2013	636,621	636,621	0	0.05	0
2014	643,741	643,741	0	0.05	0
2015	649,276	649,276	0	0.04	0
2016	654,269	654,269	0	0.04	0
2017	661,599	661,599	0	0.04	0
2018	667,717	667,717	0	0.03	0
2019	673,767	673,767	0	0.03	0
2020	680,723	680,723	0	0.03	0
2021	687,311	687,311	0	0.00	0
2022	694,002	694,002	0	0.00	0
2023	700,796	700,796	0	0.00	0
2024	707,697	707,697	0	0.00	0
2025	714,705	714,705	0	0.00	0
2026	721,821	721,821	0	0.00	0
2027	757,912	757,912	0	0.00	0
2028	795,808	795,808	0	0.00	0
2029	835,598	835,598	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S DELIVERED THROUGH SEP 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFT
(4) COLUMN (3)- COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,814	5,971	0	0	43,286	(39)	(29)	(583)	142	0	0	(177)	(3,388)	45,240
2001	61,219	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,508)	(64)	48,385
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,409)	(55)	59,122
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,499
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(0)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,677
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(6)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,057
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,996) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,068)	0	36,341
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(10)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(3)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(5)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,295
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(118)	0	39,936
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) Represents Montaup's share of Millstone 3 employee severance costs.
(b) Includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) Includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL THROUGH SEP 2004, RE-ESTIMATED OCT - DEC 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL THROUGH SEP 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK. AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT
NEWPORT ELECTRIC COMPANY
($000)

Schedule 2
Page 1c

YEAR (1)	DELTA VARIABLE COMP. (21)	NEWPORT SHARE DELTA VAR. COMP. (22)	NEWPORT ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,574)	(1,490)	2,308
2001	(12,834)	(1,521)	2,166
2002	(1,709)	(202)	714
Jan-2003	(2,061)	(244)	376
Feb-2003	(818)	(97)	224
Mar-2003	(635)	(75)	167
Apr-2003	661	78	(63)
May-2003	422	50	(100)
Jun-2003	(1,160)	(138)	125
Jul-2003	321	38	50
Aug-2003	304	36	162
Sep-2003	(171)	(20)	203
Oct-2003	219	26	32
Nov-2003	(63)	(7)	(16)
Dec-2003	(6,724)	(797)	901
2003	(9,706)	(1,150)	2,060
Jan-2004	(1,617)	(192)	429
Feb-2004	(93)	(11)	115
Mar-2004	147	17	50
Apr-2004	(530)	(63)	81
May-2004	(100)	(12)	(31)
Jun-2004	(279)	(33)	18
Jul-2004	(274)	(32)	111
Aug-2004	(293)	(35)	149
Sep-2004	(231)	(27)	164
Oct-2004	51	6	(6)
Nov-2004	51	6	(6)
Dec-2004	51	6	(6)
2004	(3,117)	(369)	1,067
Jan-2005	369	44	(44)
Feb-2005	369	44	(44)
Mar-2005	369	44	(44)
Apr-2005	369	44	(44)
May-2005	369	44	(44)
Jun-2005	369	44	(44)
Jul-2005	369	44	(44)
Aug-2005	369	44	(44)
Sep-2005	369	44	(44)
Oct-2005	369	44	(44)
Nov-2005	369	44	(44)
Dec-2005	(4,066)	(482)	482
2005	(11)	(1)	1
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 11.85%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			NEWPORT ELECTRIC COMPANY ACCOUNT							
YEAR (1)	DEFERRAL OF CONTRACT TERMINATION DATE (2)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (3)	BUYOUT SAVINGS (4)	VARIABLE RECONCIL. ADJUSTMENT (5)	DEFERRAL OF CONTRACT TERM. DATE (6)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (7)	BUYOUT SAVINGS (8)	ANNUAL SHORTFALL/ (EXCESS) (9)	ANNUAL PRE-TAX RETURN ON BALANCE (10)	COLLECTION OF PRIOR YR BAL. INCL. INTEREST (11)	END OF YR. ACCOUNT BALANCE (12)
1999	0	0	0	0	0	0	0	0	0	0	(3,744)
2000	0	0	0	(2,308)	0	0	0	(2,308)	(413)	(3,744)	(2,720)
2001	0	0	0	(2,166)	0	0	0	(2,166)	(348)	(2,844)	(2,391)
2002	0	0	0	(714)	0	0	0	(714)	(192)	(2,149)	(1,148)
Jan-2003	0	0	0	(376)	0	0	0	(376)	(13)	(52)	(1,485)
Feb-2003	0	0	0	(224)	0	0	0	(224)	(16)	(52)	(1,674)
Mar-2003	0	0	0	(167)	0	0	0	(167)	(18)	(52)	(1,807)
Apr-2003	0	0	0	63	0	0	0	63	(18)	(52)	(1,710)
May-2003	0	0	0	100	0	0	0	100	(17)	(52)	(1,575)
Jun-2003	0	0	0	(125)	0	0	0	(125)	(16)	(52)	(1,665)
Jul-2003	0	0	0	(50)	0	0	0	(50)	(17)	(52)	(1,680)
Aug-2003	0	0	0	(162)	0	0	0	(162)	(18)	(52)	(1,808)
Sep-2003	0	0	0	(203)	0	0	0	(203)	(19)	(52)	(1,979)
Oct-2003	0	0	0	(32)	0	0	0	(32)	(20)	(52)	(1,978)
Nov-2003	0	0	0	16	0	0	0	16	(20)	(52)	(1,930)
Dec-2003	0	0	0	(901)	0	0	0	(901)	(24)	(52)	(2,803)
2003	0	0	0	(2,060)	0	0	0	(2,060)	(214)	(619)	(2,803)
Jan-2004	0	0	0	(429)	0	0	0	(429)	(30)	(166)	(3,096)
Feb-2004	0	0	0	(115)	0	0	0	(115)	(31)	(166)	(3,075)
Mar-2004	0	0	0	(50)	0	0	0	(50)	(31)	(166)	(2,989)
Apr-2004	0	0	0	(81)	0	0	0	(81)	(30)	(166)	(2,934)
May-2004	0	0	0	31	0	0	0	31	(29)	(166)	(2,766)
Jun-2004	0	0	0	(18)	0	0	0	(18)	(27)	(166)	(2,644)
Jul-2004	0	0	0	(111)	0	0	0	(111)	(27)	(166)	(2,616)
Aug-2004	0	0	0	(149)	0	0	0	(149)	(26)	(166)	(2,624)
Sep-2004	0	0	0	(164)	0	0	0	(164)	(27)	(166)	(2,649)
Oct-2004	0	0	0	6	0	0	0	6	(26)	(166)	(2,502)
Nov-2004	0	0	0	6	0	0	0	6	(24)	(166)	(2,354)
Dec-2004	0	0	0	6	0	0	0	6	(23)	(166)	(2,205)
2004	0	0	0	(1,067)	0	0	0	(1,067)	(330)	(1,996)	(2,205)
Jan-2005	0	0	0	44	0	0	0	44	(21)	(197)	(1,985)
Feb-2005	0	0	0	44	0	0	0	44	(19)	(197)	(1,764)
Mar-2005	0	0	0	44	0	0	0	44	(17)	(197)	(1,540)
Apr-2005	0	0	0	44	0	0	0	44	(14)	(197)	(1,313)
May-2005	0	0	0	44	0	0	0	44	(12)	(197)	(1,085)
Jun-2005	0	0	0	44	0	0	0	44	(10)	(197)	(854)
Jul-2005	0	0	0	44	0	0	0	44	(7)	(197)	(621)
Aug-2005	0	0	0	44	0	0	0	44	(5)	(197)	(385)
Sep-2005	0	0	0	44	0	0	0	44	(3)	(197)	(147)
Oct-2005	0	0	0	44	0	0	0	44	(0)	(197)	93
Nov-2005	0	0	0	44	0	0	0	44	2	(197)	336
Dec-2005	0	0	0	(482)	0	0	0	(482)	2	(197)	53
2005	0	0	0	(1)	0	0	0	(1)	(104)	(2,364)	53
2006	0	0	0	0	0	0	0	0	3	56	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	(0)
2010	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	(0)
2014	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	(0)
2018	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	(0)
2022	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
										0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(4) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(6) COLUMN (2) x 11.85%
(7) COLUMN (3) x 11.85%
(8) COLUMN (4) x 11.85%
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 X RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

Appendix 1

**MONTAUP ELECTRIC COMPANY
AMENDMENT TO SERVICE AGREEMENT WITH
BLACKSTONE VALLEY ELECTRIC COMPANY UNDER
FERC ELECTRIC TARIFF, FIRST REVISED VOLUME NO. 1
FORMULA FOR CALCULATING CONTRACT
TERMINATION CHARGES**

1.1 The Fixed Component of the Contract Termination Charge shall include Blackstone Valley Electric Company's ("Blackstone") 29.13 percent allocated share of Montaup's costs as shown on Schedule 1, Page 2, which shall include:

1.1.1 Revenues sufficient to amortize over a twelve year period commencing on January 1, 1998 and continuing through December 31, 2009 the following plant balances and regulatory assets:

(a) Plant balances shall include unrecovered net book value as shown on Schedule 1, Page 4, Column (7), of the following Montaup generation-related investments as of December 31, 1997[1] excluding any capital additions made after December 31, 1995:

(i) Somerset Unit 6, Jet 1 and Jet 2 including general plant allocated to generation;
(ii) Montaup's ownership Share of Canal Unit 2, including capital additions past December 31, 1995, but committed prior to that date;
(iii) Montaup's and Newport's ownership share of Wyman Unit 4;
(iv) Montaup's ownership share of Millstone Unit 3;
(v) Montaup's ownership share of Seabrook Unit 1;
(vi) Montaup's Entitlements in the Vermont Yankee Unit, including the balances for materials and supplies;
(vii) Newport's generation related investment in the Diesel Units at

[1]The figures shown on Schedule 1, Page 4, Column (7) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

Jepson and Eldred;

(viii) Step-up transformers at Montaup generating units which are excluded from Montaup's transmission rates;

(ix) Montaup's non-utility property; and

(x) Generation-related property held for future use including net investment in Somerset Unit 5, through November 1, 1997, per settlement agreement in Docket ER94-1062-000.

(b) Regulatory assets shall include the generation-related unrecovered net book balances shown in Schedule 1, Page 5, Column (2), as of December 31, 1997[2]:

(i) FAS 109;

(ii) Net pension liability/(asset) of Montaup and allocated to Montaup by affiliates to the extent that they exceed 5% of the greater of the total pension benefits obligation or the fair market value of plan assets.

(iii) Unamortized deferred FAS 106 costs;

(iv) Unamortized deferred dredging costs; and

(v) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison Company.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.34 percent based on a combined state and federal income tax rate of 39.225 percent, and Montaup's 1995 year-end capital structure as shown in Schedule 1, Page 14, Column (8), including a return on common equity of 9.2 percent for the period prior to the completion of the initial divestiture process for Montaup's non-nuclear generating facilities ("Divestiture Date")[3], and sufficient to provide an overall pretax return

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[2]The figures shown on Schedule 1, Page 5, Column (2) are estimates and will be updated for actual balances as of December 31, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

[3]If Montaup sells its non-nuclear generating facilities in more than one transaction, the rights and obligations associated with the divestiture shall be allocated among the transactions using appropriate allocators. In the case of return, the allocator shall be based on the net book value of the sold facility or facilities to total net book value of the non-nuclear generating facilities in Section 1.1.1(a). This percentage allocation shall be applied to the

of 13.09 percent including a return on common equity of 11.4 percent for the period after the Divestiture Date,[4] multiplied by the average of the beginning and ending balances in each calendar year beginning in 1998 of the sum of the following:

(a) Unrecovered net book value of Montaup's generation investments as defined under 1.1.1(a) above, plus

(b) Unrecovered net book value of generation-related Regulatory Assets as defined under 1.1.1(b) above, less

(c) Deferred Taxes as shown in Schedule 1, Page 13, Column (9), equal to the combined state and federal income tax rate of 39.225 percent, which shall be adjusted for changes in tax laws, multiplied by the sum of:

(i) the unrecovered net book value of Montaup's generation investment, plus
(ii) the unrecovered net book value of generation-related regulatory assets, less
(iii) the unrecovered balance of generation investment for tax purposes, less
(iv) the unrecovered balance of generation-related assets for tax purposes.

1.1.3 Revenues sufficient to: (i) amortize over a twelve year period commencing on

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total of plant, regulatory asset balances, and deferred tax balances as set forth below.

[4]The difference between the 11.34 percent and 13.09 percent returns as applied to unamortized balances prior to the Divestiture Date shall be recovered, if divestiture occurs, through an offset to the Residual Value Credit. Effective with the merger of Montaup into the New England Power Company (NEP) on May 1, 2000, the overall pre-tax return is changed from the 13.09 percent to the return allowed in NEP's contract termination charge formula, or 12.16%. The 11.34 percent, 13.09 percent and 12.16 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. Notwithstanding the above, an equity return of 9.2% will be applied to Montaup's equity investment in the Ocean States Power facility for purposes of estimating Contract Termination Charges under the Amendment.

January 1, 1998 and continuing through December 31, 2009 the generation-related, unrecovered net book balances associated with the FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates[5]; and (ii) pay a return of 7.25 percent equal to the interest rate reflected in the actuarial analysis of the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates multiplied by the outstanding balances remaining for the FAS 106 Transition Obligation of Montaup and allocated to Montaup by affiliates. Following the Divestiture Date, these outstanding balances shall be subject to a one time adjustment as set forth in Section 1.1.4(b) below. At the same time, the interest rate return for the period after the Divestiture Date shall be established using the most current actuarial analysis available at the time, which rate shall remain in place for the remainder of the fixed cost recovery period.

1.1.4 The Fixed Components shall be subject only to the following adjustments:

(a) For each month that the Contract Termination Date is delayed beyond January 1, 1998, Montaup shall adjust the Reconciliation Account in the Variable Component of the Contract Termination Charge by an amount equal to the difference between the depreciation and amortization expense authorized under the M-14 rate and the depreciation and amortization under Section 1.1.1, together with the associated return computed in accordance with Section 1.1.2 of this Appendix, multiplied by

[5]Any FAS 106 Transition Obligation of Montaup and allocated to Montaup by its affiliates that is not allocated to generating facilities shall be deemed transmission related.

Blackstone's 29.13 percent allocated share. An exhibit showing the difference between depreciation and amortization under the M-14 rate and the Contract Termination Charge is included in Schedule 2.

(b) Following the Divestiture Date and at the time of implementing the Residual Value Credit, Montaup shall reconcile the balances in Sections 1.1.1 and 1.1.3 for Blackstone's 29.13 percent allocated share of (i) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with the FAS 106 obligation; and (ii) the unrecognized transition obligation, prior service cost, and unrecognized gains or losses associated with FAS 87 obligation, but the gains or losses associated with FAS 87 shall be recognized only to the extent that they exceed five percent of the greater of total pension benefits obligation or fair market value of plan assets. Montaup shall fund the FAS 106 and FAS 87 obligations under this Section and Section 1.2.2(f) as rapidly as permitted by the tax law up to the level of revenues collected for this purpose.[6] Any revenues associated with these obligations that cannot be immediately funded shall be put into a separate account on the books to be reserved with the return specified in Section 1.1.3 until tax deductible funding becomes possible. The one-time adjustment associated with FAS

[6]Montaup's post-divestiture FAS 106 or FAS 87 gains or losses recognized on Montaup's books shall be fully reflected in rates to customers and shall neither be retained nor borne by Montaup. Montaup shall propose an allocation of these post divestiture gains or losses between customers paying Contract Termination Charges and transmission customers.

106 and FAS 87, whether positive or negative, shall be subtracted from or added to the schedules for prospective recovery of FAS 106, as appropriate, and amortized with the return specified in Section 1.1.3 over the period between the sale and December 31, 2009. An exhibit showing the reconciliations is included in Schedule 3, page 1. In addition, Montaup shall reconcile the balances for Blackstone's 29.13 percent allocated share of (i) the FAS 109 regulatory asset; and (ii) the general plant allocated to generation, provided, however, that any general plant not allocated to generation shall be functionalized to transmission. The one-time adjustment associated with differences in the balances for FAS 109 and general plant, whether positive or negative, shall be subtracted from or added to the net proceeds reflected in the Residual Value Credit as appropriate and shall be amortized, with the return specified in Section 1.1.2, over the period between the sale and December 31, 2009.

(c) Montaup has agreed to divest its generating business within six months after the later of the Retail Access Date as defined in the Settlement filed in Docket ER97-3127-000 or the receipt of all governmental approvals and other consents necessary for the divestiture. Within three months after the completion of divestiture or the sale of any property, [7] the cost of which is

[7]Proceeds, if any, from Montaup's future leases of nuclear entitlements will also be flowed through the Residual Value Credit if such proceeds can be definitively calculated at the time the Residual Value Credit is determined. The proceeds from leases determined after the Residual Value Credit is set will be flowed through the Reconciliation Account as received.

included in the Contract Termination Charge, Montaup shall implement a Residual Value Credit as a direct offset to the Contract Termination Charges authorized under this Amendment. The Residual Value Credit will be deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. Proceeds from the divestiture which are realized after the full implementation of the Residual Value Credit will be reflected in the variable component of the CTC as hereinafter described. The Residual Value Credit to Blackstone shall be calculated as follows:

(i) Blackstone's 29.13 percent allocated share of Total Proceeds[8] equal to the sale price and other consideration received by Montaup, less

(ii) The revenues lost or gained by Montaup between July 1, 1997 and the Divestiture Date measured by the difference between the revenues excluding revenues attributable to items included in the Contract Termination Charge or in Montaup's transmission rates, that Montaup would have collected under Rate M-14 had it

[8] As part of the terms of the Divestiture, Montaup shall require the buyer of the facility to pay Montaup the net book value for all inventories and materials and supplies associated with the generating facility. As a result, inventories and materials and supplies for Montaup's non-nuclear facilities are excluded from the plant balances under Section 1.1.1, and shall be excluded from the calculation of the Residual Value Credit. In addition, the Buyer may assume other obligations that are included in the variable component of the Contract Termination Charge. Montaup reserves its right to revise the variable cost estimates and the amortization of fixed cost components in Schedule 1 to reflect the assignment of obligations to the purchasers, if such revision is necessary to maintain a stable and declining pattern of Contract Termination Charges as offset by the Residual Value Credit.

continued to make the sales to Blackstone under Tariff 1 and the revenues, excluding transmission revenues and Contract Termination Charge revenues, that it actually collected from sales to Blackstone's customers during the period, together with a credit for Blackstone's share of the revenue from sales at no less than market prices made by Montaup to third parties during the period, provided, however, the lost revenues so calculated shall not exceed $0.008 per kilowatthour multiplied by the number of kilowatthours delivered by Blackstone during the period between July 1, 1997 and the Divestiture Date, less

(iii) Blackstone's 29.13 percent allocated share of capital investments demonstrated to be prudently incurred after December 31, 1995, excluded from the plant balances in Section 1.1.1 (a) above,[9] less

(iv) Blackstone's 29.13 percent allocated share of reasonable transaction costs associated with the divestiture including the cost of necessary refinancings, repurchases, and retirements of securities occurring after May 1, 1997, less

(v) Employee severance and retraining costs pursuant to Section

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[9] Montaup's capital investments shall include construction work in progress. The investments in non-nuclear generating facilities during the period January 1, 1996 through May 31, 1997 are shown in Schedule 4. These projects have been reviewed by the parties and are included as an offset to the Residual Value Credit subject only to a further review for the reasonableness of the amounts expended in the construction of the projects under Section 3.5 of the Agreement. Montaup may include additional projects, if any, at the time of the calculation of the Residual Value Credit, subject to the dispute resolution procedures under Section 3.5 of the Agreement.

1.2.2(f).

The Net proceeds from the divestiture including amortization and the pretax return specified in Section 1.1.2 on the unreturned credit balance net of tax impacts shall be credited to the Fixed Component in equal annual amounts over the period commencing on the date the Residual Value Credit is implemented through December 31, 2009. The Residual Value Credit shall be implemented even if: (i) the Divestiture Date occurs before the Contract Termination Date, or (ii) the Residual Value Credit exceeds the Contract Termination Charge in any given year. If for any reason, generation assets which were not sold at the Divestiture Date and therefore were not in the Residual Value Credit but remained in the Contract Termination Charge, are sold at a later date, the proceeds of such a sale will be amortized, with a return as specified in Section 1.1.2, over the remaining fixed component recovery period or over a five year period, whichever period is greater, and credited to the Reconciliation Account as received.

(d) Effective with refinancings, repurchases, and retirements of securities prior to May 1, 2000 relating to assets being recovered through Contract Termination Charge, Montaup shall flow through the Reconciliation Account the annual effects associated with any differences between the 13.09 percent overall pre-tax return and the actual pre-tax return, calculated using an 11.4 percent return on common equity, attributable to changes in the cost of long-term debt, preferred stock, capital structure or income tax rates, provided that the overall pre-tax return shall not exceed 13.09 percent so long as the yield on 10-year Treasury constant maturities as reported in the Federal Reserve Statistical Release is 9 percent or lower. In the event that the yield on Treasury maturities as so reported exceeds 9 percent, the 13.09 percent overall pre-tax return shall be adjusted to include Montaup's actual cost of long-term debt and preferred stock using an 11.40 percent return on common equity. This reconciliation will apply to the period following the Divestiture Date whether or not securitization has been implemented. Notwithstanding the foregoing, nothing shall require a change in capital structure prior to any financing to take advantage of securitization.

Securitization will be implemented only if it would produce net savings to customers after taking into account all transaction costs including call provisions and prepayments, if applicable. Notwithstanding the above, savings from securitization, (pursuant to the terms of a qualified rate order), will be reflected in the Contract Termination Charge.

Any and all financing savings associated with refinancing related to divestiture and following the implementation of the Residual Value Credit, shall be allocated to the Contract Termination Charge through this paragraph, and shall not be reflected in Montaup's capital structure used for transmission rates. To the extent any financing savings are allocated to transmission rates by FERC, however, they shall not be allocated to the Contract Termination Charge under this paragraph.

1.2 The Variable Component of the Contract Termination Charge shall include Blackstone's allocated share of the items specified in Section 1.2.2, below adjusted for the Reconciliation Account discussed in Section 1.2.1.

1.2.1 The Variable Component shall be adjusted through a Reconciliation Adjustment in which differences, whether positive or negative, between the estimates for Contract Termination Charge Payments by Blackstone and Blackstone's allocated share of the estimated variable costs listed in Section 1.2.2 below and actual Contract Termination Charge payments by Blackstone and its allocated share of the actual variable costs will be accumulated in a Reconciliation Account and added to or subtracted from the Contract Termination Charge from Montaup to Blackstone. The Reconciliation Account shall also include the adjustments under Sections 1.1.2, note 4, 1.1.4(a) and 1.1.4(d) above. A pretax return equal to that specified in Section 1.1.2 shall be included on any balance in the Reconciliation Account, whether positive or negative.

Montaup shall return or collect Blackstone's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment of the Base Contract Termination Charges to Blackstone. The balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust Montaup's Base Contract Termination Charges for the following year. Reconciliation Account adjustments to the Contract Termination Charges shall not cause the Contract Termination Charges to exceed 2.8 cents per kilowatthour. Any deferrals caused by the limitation in the prior sentence shall be carried forward with a return into the next annual adjustment to the Base Contract Termination Charge.

1.2.2 Blackstone's 29.13 percent allocated share of the specific cost items included in the Variable Component are set forth in Schedule 1 at page 3. The difference between Blackstone's percent allocated share of the actual variable costs incurred by Montaup and the estimated variable costs in this section shall be included in the Reconciliation Account. The costs included in the Variable Component shall include the following:

(a) Nuclear Decommissioning and Other Post Shutdown Costs shown on Schedule 1, Pages 6 and 7, shall include: (i) all charges, excluding any net incremental decommissioning costs caused by operations after the Retail Access Date, for decommissioning and site restoration assessed to Montaup by the operators of each nuclear electric generating facility specified in Section 1.1.1(a)(iv), (v), and (vi) above, subject to the regulatory authority of the agencies having jurisdiction over the operation and collection of such funds; (ii) all other reasonable post shutdown costs associated with Montaup's entitlements in the units listed in Section 1.1.1(a), (iv), (v), and (vi) above; and (iii) all remaining reasonable costs, including decommissioning costs and unrecovered capital costs, associated with Yankee Rowe, Connecticut Yankee and Maine Yankee shown on Schedule 1, page 7. Funding for the decommissioning costs will be placed in irrevocable trusts in accordance with NRC regulations. If, upon the completion of decommissioning for any of the above listed nuclear generating facilities, it is determined that there has been an over collection of funds, such over collection will be transferred to Montaup's decommissioning fund for either Millstone 3 or Seabrook 1 pending final disposition of their decommissioning. Once all decommissioning is complete, any over collection will be refunded to Blackstone in the Reconciliation Adjustment. Other post shutdown costs will also be fully reconciled in the Reconciliation Adjustment.

Montaup's share of the Book Value of the Actual Nuclear Core at Shutdown or time of sale, which Montaup has not previously recovered through sales or lease proceeds and the Book Value of Materials and Supply at Shutdown or time of sale, which have not been addressed by other recovery mechanisms, will be recovered with a carrying charge in equal amounts over three years at a pre-tax return provided for in Section 1.1.2.

(b) Power Contract Payments will be (i) all payments by Montaup for Long-Term Power Supply Contracts less the market value realized from the resale of electricity purchased under the contracts into the wholesale market, plus (ii) Economic Buyout Payments associated with those contracts, less (iii) Credit for Unit Sales Contracts, plus (iv) the Power Contract Buyout Incentive realized.

(i) Long-Term Power Supply Contracts will be the power supply contracts listed below which were in place as of December 31, 1995, between Montaup and a third party supplier, continuing to the termination date of each contract. The Long-Term Supply Contracts include:

(1) Ocean State Power I and II
(2) Canal 1, including transmission wheeling, rental and support payments
(3) Northeast Energy Associates, including transmission wheeling payments
(4) Potter 2, including transmission wheeling payments
(5) Cleary 9
(6) McNeil, including transmission wheeling payments
(7) Blackstone Hydro, Inc., including transmission wheeling payments
(8) Hydro Quebec, including AC and DC facilities support payments
(9) Pilgrim, including transmission wheeling, rental and support payments
(10) Bear Swamp Hydro
(11) Green Mountain Power Peakers, including transmission wheeling payments

(ii) Economic Buyout Payments will be all reasonable payments agreed to by Montaup after May 1, 1997 associated with the sale, assignment, disposition or buy down of the Long-Term Power Supply Contracts. Economic Buyout Payments shall be recovered as incurred to the extent that the current recovery does not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract. The portion of the Economic Buyout Payment that cannot be recovered currently under the prior sentence shall be deferred and recovered with the return specified in Section 1.1.2 as soon as such recovery will not increase rates to customers above the level that would have been incurred absent the sale, assignment, disposition, or buy down of the Long-Term Power Supply Contract.

For purposes of calculating above market payments in (b)(i) and economic buyout payments in (b)(ii), associated with the long term supply contracts with Ocean State Power I and II, Montaup's total obligation under the contracts will be based on a return on equity of 9.2%.

(iii) Credit for Unit Sales Contracts will be all unit sales contracts entered into by Montaup as of December 31, 1995, for sales from (i) Canal Unit 2 if it is not otherwise subject to market valuation and (ii) Contract Demands to non-affiliates, less the market value of these contracts as shown in Schedule 1, Page 3, Columns (7) through (9).

(iv) Power Contract Buyout Incentive will be the sum of: (a) the Power Contract Buyout Incentive Associated with Canal 2 Divestiture calculated in accordance with Schedule 3, pages 2 and 3; and (b) the Power Contract Buyout Incentive Independent of Divestiture which shall represent 10% of the savings realized by customers as the result of the sale, assignment, disposition or buy down of its power supply contracts occurring outside of the divestiture process. The Power Contract Buyout Incentive Independent of Divestiture shall be determined at the time of the sale, assignment, disposition or buy down. The Buyout Incentive for the Ocean State Power units will be calculated in accordance with Page 4 of Schedule 3. The Total Power Contract Buyout Incentive shall not exceed $3.9 million, stated on a present value basis upon the divestiture using a discount rate equal to the actual pre-tax return in place following completion of post divestiture refinancing as determined under Section 1.1.4(d). Montaup shall document the level of the Power Contract Buyout Incentive in a report, and the amount of the Power Contract Buyout Incentive shall be subject to the dispute resolution procedures set forth under Section 3.5 of the Stipulation and Agreement. The Power Contract Buyout Incentive Associated with Canal 2 Divestiture will be recovered in equal increments over the period from the divestiture through December 31, 2009, with appropriate adjustments for the time value of money, and the Power Contract Buyout Incentive Independent of Divestiture will be recovered in equal increments over the remaining term of the related purchased power contract, with appropriate adjustments for the time value of money.

(c) <u>Above Market Fuel Transportation</u> as shown in Schedule 1, Page 15, Column 10 will be Montaup's continuing long-term payment obligations associated with Capacity Payments to Algonquin Natural Gas Pipeline for Canal 2 less the market value of that capacity. The Market Value of

Capacity Payments to Algonquin Natural Gas Pipelines will equal the actual proceeds associated with the sale or assignment or termination of contractual obligations. For the purposes of calculating the Contract Termination Charges, prior to the date that Montaup's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the Market Value of Capacity Payments to Algonquin Natural Gas Pipeline shall be deemed to equal the savings associated with actual unit operation on natural gas compared to the unit's avoided operation on oil at prevailing market prices. For illustrative purposes, the amounts shown on page 15 of Schedule 1 reflect a market value which is 50 percent of the capacity payments.

(d) Transmission wheeling, rental and support charges as shown in Schedule 1, Page 3, associated with the transmission of electricity from Montaup's entitlements in Seabrook Unit 1, Millstone Unit 3, Wyman Unit 4, Canal Unit 2, Vermont Yankee, which units are located off of Montaup's transmission system. These wheeling and support payments shall include only costs that are excluded from recovery under Montaup's and NEPOOL's open access transmission tariffs or are not assigned to a purchaser of the unit.

(e) Payments in Lieu of Property Taxes will include all reasonable costs incurred by Montaup or its affiliates associated with payments in lieu of property taxes to the cities and towns in which Montaup owns generating facilities to mitigate the loss of tax revenues that those cities and towns would otherwise incur in connection with restructuring. For the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciling Account, the Payments in Lieu of Property Taxes are assumed to be zero.

(f) Employee Severance and Retraining Costs as shown in Schedule 1, page 3, Column (13), will include all reasonable costs and expenses incurred by Montaup or its affiliates associated with the adjustment of their workforces in connection with the implementation of retail access, divestiture, or the termination of Montaup's Tariff No.1, including, but not limited to early retirement, severance, retraining and other reasonable costs associated with the implementation of the benefits to employees included in Schedule 5. The recovery of costs under this paragraph incurred by Montaup or its affiliates are limited to $15 million.[10] In the event that the acutal costs incurred under this paragraph are less than $15 million, excluding costs found by FERC to be recoverable in Montaup's transmission rates, Montaup shall flow back the difference to customers in the Reconciliation Account. The procedure established in this paragraph shall be the exclusive method for recovering the costs under this

[10]The parties agree that $11.8 million will be reserved for Montaup and EUASC employees and estimate that $3.2 million will be reserved for Canal 2 and paid by the buyer of Canal 2. The Canal 2 figure may be adjusted when actual figures are available from Canal Electric.

paragraph, and, except in the event of legislation changing required benefits, neither Montaup nor its affiliates shall be able to recover more than $15 million, subject to the Canal 2 adjustment, for these costs. Thus, for the purposes of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Employee Severance and Retraining Costs are assumed to be zero and, except in the event of legislation changing required benefits, these costs shall not result in an increase to the Reconciliation Account or to the Contract Termination Charge.

(g) Damages, Costs, or Net Recoveries from claims by or against third parties shall include all damages, costs, or recoveries associated with Montaup's generating business which accrued prior to the date of divestiture and which were not: (i) included in the reserves for generation related, uninsured claims other than claims associated with Environmental Response Costs as of May 21, 1994, plus annual additions to the reserves for uninsured claims in Montaup's M-14 rate, less actual payments out of the reserve for generation related claims during the period from May 21, 1994 through the Contract Termination Date; (ii) assigned to Montaup's successor in interest; (iii) recovered from Montaup's insurance carriers; or (iv) the result of gross negligence. For the purposes of calculating the Base Contract Termination Charges and the estimate included in Reconciliation Account, Damages, Costs, or Net Recoveries from claims are assumed to be zero.

(h) Performance Based Rate for Nuclear Units Remaining After Divestiture shall credit value received that is not otherwise reflected in the Residual Value Credit, or recover any payments or costs associated with the sale, lease or disposal of Montaup's minority ownership share of the Seabrook, Millstone #3, and Vermont Yankee Nuclear Units ("PBR Nuclear Units") that are not otherwise reflected in the Residual Value Credit. If Montaup is unable to sell, lease, assign, or otherwise dispose of its PBR Nuclear Units on the terms set forth in the Stipulation and Agreement prior to the Contract Termination Date, the Performance Based Rate shall include 80 percent of the reasonable going forward costs, including variable costs and post-1995 capital additions on a cost of service basis,[11] associated with Montaup's PBR Nuclear Units that are not otherwise recovered in contract termination charges less 80 percent of the revenues from sales of energy or capacity from such units or entitlements that are not otherwise reflected in contract termination charges. The Performance Based Rate shall apply for the period from the Contract Termination Date to the date that Montaup either sells, leases, assigns or otherwise disposes of the PBR Nuclear Units or to the date such units are shutdown. Within six months prior to

[11] In the event that the nuclear unit is retired before the end of its license life, the capital addition shall be amortized with a return over the remainder of the license or in accordance with its depreciation schedule, whichever is shorter.

implementing the Performance Based Rate, Montaup will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard with a maximum potention credit for nonperformance of $250,000. Such sales, if any, shall not be made directly to Blackstone's retail customers, however, Montaup shall retain the right to use its minority shares of the PBR Nuclear Units to fulfill its backstop obligations under the standard offer. For the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account, the Performance Based Rate for Nuclear Units is assumed to be zero.

(i) Environmental Response Costs defined as:

(i) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Blackstone relating to deposits or waste from divested generating facilities off the site of properties sold, whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv), including material deposited before the Divestiture Date at disposal sites, sites to which material may have migrated from off-site disposal sites, or any off-site location at which generation related material may have been deposited before the Divestiture Date associated with the operation of generating facilities sold pursuant to the divestiture plan;

(ii) Reasonable and prudently incurred costs associated with the investigation, testing, remediation, liabilities, damages, claims, settlements, or judgments attributable to or incurred by Montaup or Blackstone relating to deposits and wastes occurring prior to the Divestiture Date whether or not such material is regulated under the statutes and authorities referenced in paragraph (iv) from facilities located with the switchyards for which Montaup will retain a permanent easement on parcels that are otherwise being divested if such costs are not recovered in transmission rates;

(iii) Reasonable and prudently incurred costs associated with the purchase of property that is acquired as part of an overall mitigation and response plan associated with sites identified in paragraphs (i) and (ii);

(iv) The statutes and authorities referenced in paragraphs (i) and (ii) shall be the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), Massachusetts G.L. c. 21C and 21E, and Rhode Island General Laws 23-19.14, or any other laws, regulations or orders by courts or governmental authorities, or resulting from claims and contentions arising in tort, breach of contract or violation of law;

(v) Except for property acquired under paragraph (iii), Environmental Response Costs shall not include costs associated with the investigation, testing, remediation, or other liabilities relating to property acquired after the Divestiture Date. Environmental Response Costs recovered under paragraphs (i), (ii), and (iii) shall also be offset by: (i) proceeds from insurance companies related to Environmental Response Costs; (ii) proceeds from the sale of properties purchased under paragraph (iii); and (iii) recoveries from third parties;

(vi) Nothing herein is intended to limit, alter, or otherwise affect any liability of Montaup to governmental authorities or third parties other than the buyer or buyers of Montaup generating facilities under any environmental law including those referenced in paragraph (iv).

(j) Amortization of generation-related deferred investment tax credits through December 31, 2009. These amounts are shown on Schedule 1, page 15 of 15, Column 10, effective April 1, 1999.

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MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO BLACKSTONE VALLEY ELECTRIC

Schedule 1
Page 1 of 15

YEAR	EST. BVE MWH SALES	SHARE OF FIXED COMPONENT $ IN 000	SHARE OF FIXED COMPONENT CENTS/KWH	SHARE OF VAR. COMPONENT $ IN 000	SHARE OF VAR. COMPONENT CENTS/KWH	SHARE OF TOTAL TERM CHARGE $ IN 000	BASE CONTRACT TERM CHARGE CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
PRE RVC '99	327,284	4,021	1.23	5,797	1.77	9,819	3.00
POST RVC '99	981,853	9,866	1.00	10,198	1.04	20,064	2.04
2000	1,329,905	17,717	1.33	9,065	0.68	26,782	2.01
2001	1,346,024	8,079	0.60	12,689	0.94	20,767	1.54
2002	1,360,074	7,340	0.54	13,936	1.02	21,276	1.56
2003	1,377,851	10,865	0.79	13,392	0.97	24,257	1.76
2004	1,399,848	11,204	0.80	10,218	0.73	21,422	1.53
2005	1,423,866	9,647	0.68	10,272	0.72	19,919	1.40
2006	1,452,574	395	0.03	13,020	0.90	13,415	0.92
2007	1,471,219	8,550	0.58	8,906	0.61	17,456	1.19
2008	1,493,432	5,586	0.37	5,976	0.40	11,562	0.77
2009	1,512,696	7,986	0.53	5,856	0.39	13,842	0.92
2010	1,534,838	0	0.00	2,666	0.17	2,666	0.17
2011	1,550,396	0	0.00	923	0.06	923	0.06
2012	1,566,958	0	0.00	837	0.05	837	0.05
2013	1,597,666	0	0.00	752	0.05	752	0.05
2014	1,624,096	0	0.00	730	0.04	730	0.04
2015	1,644,785	0	0.00	708	0.04	708	0.04
2016	1,671,116	0	0.00	687	0.04	687	0.04
2017	1,693,977	0	0.00	579	0.03	579	0.03
2018	1,713,946	0	0.00	561	0.03	561	0.03
2019	1,739,097	0	0.00	544	0.03	544	0.03
2020	1,762,428	0	0.00	461	0.03	461	0.03
2021	1,787,024	0	0.00	0	0.00	0	0.00
2022	1,811,988	0	0.00	0	0.00	0	0.00
2023	1,837,328	0	0.00	0	0.00	0	0.00
2024	1,863,048	0	0.00	0	0.00	0	0.00
2025	1,889,155	0	0.00	0	0.00	0	0.00
2026	1,915,656	0	0.00	0	0.00	0	0.00
2027	2,011,439	0	0.00	0	0.00	0	0.00
2028	2,112,011	0	0.00	0	0.00	0	0.00
2029	2,217,611	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	9,035	5,507	357	**14,900**	0	14,900
PRE RVC '99	2,129	1,806	86	**4,021**	0	4,021
POST RVC '99	7,276	5,366	(63)	**12,578**	(2,712)	9,866
2000	8,395	12,957	(89)	**21,263**	(3,546)	17,717
2001	7,489	4,186	(86)	**11,589**	(3,510)	8,079
2002	7,165	3,767	(82)	**10,850**	(3,510)	7,340
2003	6,696	7,758	(78)	**14,375**	(3,510)	10,865
2004	6,023	8,766	(75)	**14,714**	(3,510)	11,204
2005	5,345	7,883	(71)	**13,157**	(3,510)	9,647
2006	2,439	1,533	(67)	**3,905**	(3,510)	395
2007	1,963	10,160	(64)	**12,060**	(3,510)	8,550
2008	1,227	7,930	(60)	**9,097**	(3,510)	5,586
2009	452	11,100	(56)	**11,496**	(3,510)	7,986

COLUMN NOTES:
EACH COLUMN REPRESENTS 29.13% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
VARIABLE COMPONENT

		POWER CONTRACTS				CREDIT FOR UNIT SALES CONTRACTS											
YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	POWER TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	2,334	42,517	20,062	22,454	0	(1,414)	0	(1,414)	138	385	0	0	0	0	23,897	0	**23,897**
PRE RVC '99	538	10,639	5,182	5,456	0	(324)	0	(324)	33	94	0	0	0	0	5,797	0	**5,797**
POST RVC '99	2,073	10,803	0	10,803	0	(633)	0	(633)	(188)	106	0	0	0	0	12,161	(1,964) **(a)**	**10,198**
2000	2,460	14,711	0	14,711	0	(237)	0	(237)	(144)	56	0	0	0	0	16,846	(7,781) **(b)**	**9,065**
2001	2,128	15,742	0	15,742	0	0	0	0	(90)	56	0	0	0	0	17,836	(5,147)	**12,689**
2002	1,901	15,803	0	15,803	0	0	0	0	0	16	0	0	0	0	17,720	(3,784)	**13,936**
2003	1,739	11,674	0	11,674	0	0	0	0	0	0	0	0	0	0	13,413	(21)	**13,392**
2004	1,688	10,853	0	10,853	0	0	0	0	0	0	0	0	0	0	12,541	(2,324)	**10,218**
2005	1,648	11,883	0	11,883	0	0	0	0	0	0	0	0	0	0	13,530	(3,258)	**10,272**
2006	2,507	10,372	0	10,372	0	0	0	0	0	0	0	0	0	0	12,880	140	**13,020**
2007	2,300	6,606	0	6,606	0	0	0	0	0	0	0	0	0	0	8,906	0	**8,906**
2008	1,993	3,983	0	3,983	0	0	0	0	0	0	0	0	0	0	5,976	0	**5,976**
2009	1,778	4,078	0	4,078	0	0	0	0	0	0	0	0	0	0	5,856	0	**5,856**
2010	1,719	947	0	947	0	0	0	0	0	0	0	0	0	0	2,666	0	**2,666**
2011	0	923	0	923	0	0	0	0	0	0	0	0	0	0	923	0	**923**
2012	0	837	0	837	0	0	0	0	0	0	0	0	0	0	837	0	**837**
2013	0	752	0	752	0	0	0	0	0	0	0	0	0	0	752	0	**752**
2014	0	730	0	730	0	0	0	0	0	0	0	0	0	0	730	0	**730**
2015	0	708	0	708	0	0	0	0	0	0	0	0	0	0	708	0	**708**
2016	0	687	0	687	0	0	0	0	0	0	0	0	0	0	687	0	**687**
2017	0	579	0	579	0	0	0	0	0	0	0	0	0	0	579	0	**579**
2018	0	561	0	561	0	0	0	0	0	0	0	0	0	0	561	0	**561**
2019	0	544	0	544	0	0	0	0	0	0	0	0	0	0	544	0	**544**
2020	0	461	0	461	0	0	0	0	0	0	0	0	0	0	461	0	**461**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 29.13% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)		$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)		UNRECOVERED BALANCE @ APRIL 1, 1999
FOSSIL FUEL UNITS										
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032		23,716	2,158		22,222
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041		35,207	2,917		32,990
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030		1,806	112		1,692
NEWPORT DIESELS	JAMESTOWN/	1961	DIESEL	8.8	1,803		1,499	152		1,405
	PORTSMOUTH, RI/	1978	DIESEL	8.3						
	YARMOUTH, ME	1978	OIL	4.1						
NUCLEAR UNITS										
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705		160,949	4,878		150,813
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749		128,279	4,735		120,200
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786	(a)	3,092	347		2,897
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439	(a)	6,105	667		5,721
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604		604			566
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860		6,449		(b)	6,043
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610		2,610			2,446
			TOTAL	542.6	401,659		370,316	15,966		346,994

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF		APPLICABLE AMORTIZATION			
	DECEMBER 31, 1995	DECEMBER 31, 1997	FOR 1996 AND BEYOND		BASIS FOR DEFERRAL	UNRECOVERED BALANCE @ APRIL 1, 1999
	(1)	(2)	(3)		(4)	
FAS 109 - ASSET	39,916	37,466	1,225		FERC RATEMAKING POLICY	35,106
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)		FERC RATEMAKING POLICY	(1,263)
- ITC GROSS-UP	(8,119)	(7,369)	(375)			(6,905)
FAS 106 DEFERRAL	1,313	538	387	(a)	FERC RATEMAKING POLICY	504
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)		FAS 87	(389)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607		FERC RATEMAKING POLICY	9,993
UNAMORTIZED ITC	(12,523)	(11,367)	(578)		FERC RATEMAKING POLICY	(10,651)
DREDGING	424	173	125	(b)	FERC RATEMAKING POLICY	162
TOTAL REG. ASSETS	27,941	28,343	(202)			26,558

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95			9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)			534	
DISCOUNT RATE			7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
PRE RVC '99	167	133	300	7,187
POST RVC '99	(124)	(93)	(218)	(1,866) (a)
2000	(187)	(120)	(306)	(1,680)
2001	(187)	(107)	(294)	(1,493)
2002	(187)	(94)	(281)	(1,306)
2003	(187)	(82)	(269)	(1,120)
2004	(187)	(69)	(256)	(933)
2005	(187)	(57)	(243)	(747)
2006	(187)	(44)	(231)	(560)
2007	(187)	(31)	(218)	(373)
2008	(187)	(19)	(206)	(187)
2009	(187)	(6)	(193)	0

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UF
$ IN 000

Schedule 1
Page 5b of 15

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,757)	(6,185)	(2,489)	(140)	(1,984)	(17,556)
						(4,614)
POST RVC '99	(336)	(308)	0	0	0	(644)
2000	0	(494)	0	0	0	(494)
2001	0	(309)	0	0	0	(309)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	0	**1,195**	**68**	3,944
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,521
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	10,660	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	31,016	18,907	1,226	**51,148**	0	51,148
PRE RVC '99	7,309	6,200	300	**13,810**	0	13,810
POST RVC '99	24,977	18,420	(218)	**43,179**	(9,309)	33,870
2000	28,821	44,481	(306)	**72,995**	(12,173)	60,822
2001	25,708	14,369	(294)	**39,783**	(12,050)	27,733
2002	24,596	12,932	(281)	**37,247**	(12,050)	25,197
2003	22,986	26,631	(269)	**49,349**	(12,050)	37,298
2004	20,676	30,093	(256)	**50,513**	(12,050)	38,463
2005	**18,349**	**27,062**	(243)	**45,168**	(12,050)	33,118
2006	8,374	5,263	(231)	**13,407**	(12,050)	1,357
2007	6,740	34,878	(218)	**41,400**	(12,050)	29,350
2008	4,211	27,221	(206)	**31,227**	(12,050)	19,177
2009	1,552	38,106	(193)	**39,464**	(12,050)	27,414

<u>COLUMN NOTES:</u>
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.2913 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17)/.2913.
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	352,754	26,999	379,752	64,971	0	64,971	314,781	123,473
PRE RVC '99	346,994	26,558	373,552	63,910	0	63,910	309,641	121,457
POST RVC '99	324,978 (a)	42,378 (a)	367,356 (a)	57,901	0	57,901	309,455	121,384
2000	285,629	37,247	322,876	50,890	0	50,890	271,985	106,686
2001	272,918	35,589	308,507	48,626	0	48,626	259,881	101,938
2002	261,478	34,097	295,575	46,587	0	46,587	248,988	97,666
2003	237,919	31,025	268,944	42,390	0	42,390	226,554	88,866
2004	211,298	27,554	238,851	37,647	0	37,647	201,205	78,922
2005	93,302	12,167	105,468	16,623	0	16,623	88,845	34,849
2006	88,646	11,560	100,205	15,794	0	15,794	84,411	33,110
2007	57,791	7,536	65,327	10,297	0	10,297	55,031	21,586
2008	33,710	4,396	38,106	6,006	0	6,006	32,100	12,591
2009	0	0	0	0	0	0	0	0

<u>COLUMN NOTES:</u>
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)		SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039					
1998	379,752	123,473	256,280	262,659		29,781	1,235	31,016
PRE RVC '99	373,552	121,457	252,095	247,911	(a)	7,027	282	7,309
POST RVC '99	367,356	121,384	245,973	254,372	(b)	24,977	0	24,977
2000	322,876	106,686	216,190	231,081		28,821	0	28,821
2001	308,507	101,938	206,569	211,379		25,708	0	25,708
2002	295,575	97,666	197,910	202,239		24,596	0	24,596
2003	268,944	88,866	180,078	188,994		22,986	0	22,986
2004	238,851	78,922	159,929	170,003		20,676	0	20,676
2005	105,468	34,849	70,619	115,274		**18,349**	0	18,349
2006	100,205	33,110	67,095	68,857		8,374	0	8,374
2007	65,327	21,586	43,741	55,418		6,740	0	6,740
2008	38,106	12,591	25,515	34,628		4,211	0	4,211
2009	0	0	0	12,757		1,552	0	1,552

EECo 12/31/95 **CAPITAL STRUCTURE**				PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000			ATWACC	BTWACC
COM PRE RVC	48.45%	9.20%	(c)	4.46%	7.33%	5.52%	9.09%	57.35%	11.00%	(c)	6.31%	10.38%
COM POST RVC		11.40%										
PFD PRE RVC	5.95%	9.83%		0.58%	0.96%	0.58%	0.96%	0.21%	6.00%		0.01%	0.02%
LTD PRE RVC	45.60%	6.67%		3.04%	3.04%	3.04%	3.04%	42.44%	4.15%		1.76%	1.76%
	100.00%			8.08%	11.338%	9.15%	13.092%	100.00%			8.08%	12.162%
TAX RATE					39.225%		39.225%					39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND DEF TAXES OF ($17,847) AND $7,001 FOR ITC LIAB AND, $5,815 AND $1,461 FOR MAINE YANKEE
(c) PER NEP RI FILING.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,521	17,790	18,731	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,901**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(644)	364	0	0	0	0	**41,749**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(494)	193	0	0	0	0	**57,831**
2001	7,304	54,041	0	54,041	0	0	0	0	(309)	193	0	0	0	0	**61,229**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	BLACKSTONE VALLEY REVENUE EXCESS/ (SHORTFALL) (6)
2000	1,329,905	1,353,414	23,509	2.01	352
2001	1,346,024	1,350,390	(4,366)	1.54	29
2002	1,360,074	1,364,403	(4,328)	1.56	(4)
Jan-2003	114,821	126,572	(11,751)	1.76	71
Feb-2003	114,821	116,475	(1,654)	1.76	29
Mar-2003	114,821	110,251	4,570	1.76	(81)
Apr-2003	114,821	103,044	11,777	1.76	(208)
May-2003	114,821	104,483	10,338	1.76	(183)
Jun-2003	114,821	102,290	12,531	1.76	(221)
Jul-2003	114,821	124,693	(9,872)	1.76	173
Aug-2003	114,821	132,119	(17,298)	1.76	304
Sep-2003	114,821	123,055	(8,234)	1.76	144
Oct-2003	114,821	109,256	5,565	1.76	(99)
Nov-2003	114,821	109,428	5,393	1.76	(95)
Dec-2003	114,821	122,955	(8,135)	1.76	143
2003	1,377,851	1,384,622	(6,771)	1.76	(23)
Jan-2004	116,654	115,422	1,232	1.53	123
Feb-2004	116,654	117,641	(987)	1.53	15
Mar-2004	116,654	116,435	219	1.53	(4)
Apr-2004	116,654	102,351	14,303	1.53	(219)
May-2004	116,654	104,274	12,380	1.53	(190)
Jun-2004	116,654	118,093	(1,439)	1.53	22
Jul-2004	116,654	115,540	1,114	1.53	(17)
Aug-2004	116,654	119,279	(2,625)	1.53	40
Sep-2004	116,654	126,650	(9,996)	1.53	153
Oct-2004	116,654	**116,654**	0	1.53	(0)
Nov-2004	116,654	**116,654**	0	1.53	(0)
Dec-2004	116,654	**116,654**	0	1.53	(0)
2004	1,399,848	1,385,648	14,200	1.53	(79)
Jan-2005	118,656	118,656	0	1.40	0
Feb-2005	118,656	118,656	0	1.40	0
Mar-2005	118,656	118,656	0	1.40	0
Apr-2005	118,656	118,656	0	1.40	0
May-2005	118,656	118,656	0	1.40	0
Jun-2005	118,656	118,656	0	1.40	0
Jul-2005	118,656	118,656	0	1.40	0
Aug-2005	118,656	118,656	0	1.40	0
Sep-2005	118,656	118,656	0	1.40	0
Oct-2005	118,656	118,656	0	1.40	0
Nov-2005	118,656	118,656	0	1.40	0
Dec-2005	118,656	118,656	0	1.40	0
2005	1,423,866	1,423,866	0	1.40	0
2006	1,452,574	1,452,574	0	0.92	0
2007	1,471,219	1,471,219	0	1.19	0
2008	1,493,432	1,493,432	0	0.77	0
2009	1,512,696	1,512,696	0	0.92	0
2010	1,534,838	1,534,838	0	0.17	0
2011	1,550,396	1,550,396	0	0.06	0
2012	1,566,958	1,566,958	0	0.05	0
2013	1,597,666	1,597,666	0	0.05	0
2014	1,624,096	1,624,096	0	0.04	0
2015	1,644,785	1,644,785	0	0.04	0
2016	1,671,116	1,671,116	0	0.04	0
2017	1,693,977	1,693,977	0	0.03	0
2018	1,713,946	1,713,946	0	0.03	0
2019	1,739,097	1,739,097	0	0.03	0
2020	1,762,428	1,762,428	0	0.03	0
2021	1,787,024	1,787,024	0	0.00	0
2022	1,811,988	1,811,988	0	0.00	0
2023	1,837,328	1,837,328	0	0.00	0
2024	1,863,048	1,863,048	0	0.00	0
2025	1,889,155	1,889,155	0	0.00	0
2026	1,915,656	1,915,656	0	0.00	0
2027	2,011,439	2,011,439	0	0.00	0
2028	2,112,011	2,112,011	0	0.00	0
2029	2,217,611	2,217,611	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S THROUGH SEP. 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFTER.
(4) COLUMN (3) - COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,831	5,971	0	0	43,286	(39)	(29)	(584)	142	0	0	(182)	(3,390)	45,233
2001	61,229	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,563)	(72)	48,322
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,416)	(61)	59,110
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,498
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(1)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,676
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(7)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,056
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,997) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,071)	0	36,338
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(11)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(4)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(6)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,294
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(121)	0	39,933
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) represents Montaup's share of Millstone 3 employee severance costs.
(b) includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004, RE-ESTIMATED OCT. - DEC. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 16, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK. AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT **Schedule 2**
BLACKSTONE VALLEY ELECTRIC **Page 1c**
($000)

YEAR (1)	DELTA VARIABLE COMP. (21)	BLACKSTONE VALLEY SHARE DELTA VAR. COMP. (22)	BLACKSTONE VALLEY ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,598)	(3,670)	4,021
2001	(12,907)	(3,760)	3,788
2002	(1,721)	(501)	497
Jan-2003	(2,061)	(600)	671
Feb-2003	(818)	(238)	267
Mar-2003	(636)	(185)	104
Apr-2003	661	193	(400)
May-2003	421	123	(305)
Jun-2003	(1,161)	(338)	117
Jul-2003	321	93	80
Aug-2003	303	88	215
Sep-2003	(171)	(50)	194
Oct-2003	219	64	(162)
Nov-2003	(63)	(18)	(77)
Dec-2003	(6,724)	(1,959)	2,101
2003	(9,709)	(2,828)	2,805
Jan-2004	(1,618)	(471)	594
Feb-2004	(93)	(27)	42
Mar-2004	146	43	(46)
Apr-2004	(530)	(154)	(65)
May-2004	(100)	(29)	(161)
Jun-2004	(279)	(81)	103
Jul-2004	(274)	(80)	62
Aug-2004	(293)	(85)	125
Sep-2004	(232)	(67)	220
Oct-2004	51	15	(15)
Nov-2004	51	15	(15)
Dec-2004	51	15	(15)
2004	(3,120)	(909)	830
Jan-2005	369	107	(107)
Feb-2005	369	107	(107)
Mar-2005	369	107	(107)
Apr-2005	369	107	(107)
May-2005	369	107	(107)
Jun-2005	369	107	(107)
Jul-2005	369	107	(107)
Aug-2005	369	107	(107)
Sep-2005	369	107	(107)
Oct-2005	369	107	(107)
Nov-2005	369	107	(107)
Dec-2005	(4,066)	(1,185)	1,185
2005	(11)	(3)	3
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 29.13%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY ELECTRIC SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			BLACKSTONE VALLEY ELECTRIC COMPANY ACCOUNT							
YEAR	DEFERRAL OF CONTRACT TERMINATION DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	VARIABLE RECONCIL. ADJUSTMENT	DEFERRAL OF CONTRACT TERM. DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	ANNUAL SHORTFALL/ (EXCESS)	ANNUAL PRE-TAX RETURN ON BALANCE	COLLECTION OF PRIOR YR BAL. INCL. INTEREST	END OF YR. ACCOUNT BALANCE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1999	0	0	0	0	0	0	0	0	0	0	(7,781)
2000	0	0	0	(4,021)	0	0	0	(4,021)	(789)	(7,781)	(4,810)
2001	0	0	0	(3,788)	0	0	0	(3,788)	(626)	(5,147)	(4,078)
2002	0	0	0	(497)	0	0	0	(497)	(251)	(3,784)	(1,041)
Jan-2003	0	0	0	(671)	0	0	0	(671)	(14)	(2)	(1,725)
Feb-2003	0	0	0	(267)	0	0	0	(267)	(19)	(2)	(2,009)
Mar-2003	0	0	0	(104)	0	0	0	(104)	(21)	(2)	(2,132)
Apr-2003	0	0	0	400	0	0	0	400	(20)	(2)	(1,749)
May-2003	0	0	0	305	0	0	0	305	(16)	(2)	(1,458)
Jun-2003	0	0	0	(117)	0	0	0	(117)	(15)	(2)	(1,589)
Jul-2003	0	0	0	(80)	0	0	0	(80)	(16)	(2)	(1,683)
Aug-2003	0	0	0	(215)	0	0	0	(215)	(18)	(2)	(1,915)
Sep-2003	0	0	0	(194)	0	0	0	(194)	(20)	(2)	(2,128)
Oct-2003	0	0	0	162	0	0	0	162	(21)	(2)	(1,985)
Nov-2003	0	0	0	77	0	0	0	77	(20)	(2)	(1,926)
Dec-2003	0	0	0	(2,101)	0	0	0	(2,101)	(30)	(2)	(4,055)
2003	0	0	0	(2,805)	0	0	0	(2,805)	(230)	(21)	(4,055)
Jan-2004	0	0	0	(594)	0	0	0	(594)	(43)	(194)	(4,499)
Feb-2004	0	0	0	(42)	0	0	0	(42)	(45)	(194)	(4,392)
Mar-2004	0	0	0	46	0	0	0	46	(43)	(194)	(4,196)
Apr-2004	0	0	0	65	0	0	0	65	(41)	(194)	(3,978)
May-2004	0	0	0	161	0	0	0	161	(39)	(194)	(3,663)
Jun-2004	0	0	0	(103)	0	0	0	(103)	(37)	(194)	(3,609)
Jul-2004	0	0	0	(62)	0	0	0	(62)	(36)	(194)	(3,513)
Aug-2004	0	0	0	(125)	0	0	0	(125)	(35)	(194)	(3,480)
Sep-2004	0	0	0	(220)	0	0	0	(220)	(35)	(194)	(3,542)
Oct-2004	0	0	0	15	0	0	0	15	(35)	(194)	(3,368)
Nov-2004	0	0	0	15	0	0	0	15	(33)	(194)	(3,192)
Dec-2004	0	0	0	15	0	0	0	15	(31)	(194)	(3,015)
2004	0	0	0	(830)	0	0	0	(830)	(453)	(2,324)	(3,015)
Jan-2005	0	0	0	107	0	0	0	107	(29)	(272)	(2,665)
Feb-2005	0	0	0	107	0	0	0	107	(25)	(272)	(2,311)
Mar-2005	0	0	0	107	0	0	0	107	(21)	(272)	(1,953)
Apr-2005	0	0	0	107	0	0	0	107	(18)	(272)	(1,592)
May-2005	0	0	0	107	0	0	0	107	(14)	(272)	(1,228)
Jun-2005	0	0	0	107	0	0	0	107	(11)	(272)	(859)
Jul-2005	0	0	0	107	0	0	0	107	(7)	(272)	(487)
Aug-2005	0	0	0	107	0	0	0	107	(3)	(272)	(111)
Sep-2005	0	0	0	107	0	0	0	107	1	(272)	269
Oct-2005	0	0	0	107	0	0	0	107	5	(272)	652
Nov-2005	0	0	0	107	0	0	0	107	9	(272)	1,039
Dec-2005	0	0	0	(1,185)	0	0	0	(1,185)	6	(272)	132
2005	0	0	0	(3)	0	0	0	(3)	(108)	(3,258)	132
2006	0	0	0	0	0	0	0	0	8	140	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2008	0	0	0	0	0	0	0	0	(0)	(0)	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2012	0	0	0	0	0	0	0	0	(0)	(0)	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2016	0	0	0	0	0	0	0	0	(0)	(0)	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2020	0	0	0	0	0	0	0	0	(0)	(0)	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2024	0	0	0	0	0	0	0	0	(0)	(0)	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 x RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

ATTACHMENT B

The USGen Settlement

SETTLEMENT AND CTC IMPLEMENTATION AGREEMENT SURROUNDING ISSUES RELATED TO THE RESOLUTION OF THE USGENNE BANKRUPTCY PROCEEDING

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMMISSION

New England Power Company) Docket ER-___

AGREEMENT TO AMEND NEP/NARRAGANSETT ELECTRIC COMPANY T1 SERVICE AGREEMENTSETTLEMENT AND CTC IMPLEMENTATION AGREEMENT

WHEREAS, New England Power Company ("NEP"), Narragansett Electric Company ("Narragansett"), the Rhode Island Attorney General, the Rhode Island Public Utilities Commission ("Rhode Island Commission") and the Rhode Island Division of Public Utilities and Carriers ("Rhode Island Division") entered into a comprehensive restructuring agreement that was approved by this Commission in Docket Nos. ER97-680-000 and ER98-6-000 for NEP, and a parallel restructuring agreement in Docket No. ER97-2800-000 between the former Montaup Electric Company ("Montaup"), which has merged into NEP, and the former Blackstone Valley Electric Company and Newport Electric Corporation, which have merged into Narragansett (the "Agreements").

WHEREAS, NEP and Narragansett entered into an amended service agreement under NEP's FERC Electric Tariff, Original Volume No. 1 ("NEP/Narragansett T1 Service Agreement").

WHEREAS, under those Agreements, NEP and Montaup are also required to make annual reconciliations of the Contract Termination Charges ("CTC").

WHEREAS, NEP, Narragansett (together, the "National Grid Companies"), the Rhode Island Commission and the Rhode Island Division (altogether, the "Parties") have entered into this CTC Implementation Agreement ("Settlement") with regard to issues presented as a result of the bankruptcy of USGen New England, Inc. ("USGenNE") as more fully described in the National Grid Companies Proposed CTC Mitigation Plan, USGen New England, Inc. Bankruptcy Settlement ("CTC Mitigation Plan") submitted to the Rhode Island Commission on June 21, 2005.

WHEREAS, as part of the bankruptcy, USGenNE rejected certain contractual commitments with NEP[1] and National Grid USA's New England distribution companies, Massachusetts Electric Company and Nantucket Electric Company (together "Mass. Electric"), Narragansett and Granite State Electric Company ("Granite State") related to:

(1) the Asset Purchase Agreement dated as of August 5, 1997 by and among NEP, Narragansett and USGenNE (as amended, the "APA"), for the sale by NEP and Narragansett to USGenNE of substantially all of NEP's non-nuclear generating assets (fossil and hydroelectric generating stations) with certain related liabilities and obligations;

(2) the Amended and Restated Power Purchase Agreement Transfer Agreement dated October 29, 1997 by and between NEP and USGenNE, as amended, ("PPATA") relating to a portfolio of power contracts with independent power producers;

[1] NEP's costs under the CTC also include the costs of Narragansett's generating entitlements in Rhode Island that NEP assumed under the Integrated Facilities Agreement, prior to industry restructuring. The CTC for the Massachusetts and Rhode Island distribution companies also includes charges from Montaup. However, Montaup's CTC was not affected by the USGenNE bankruptcy and settlement. As a result, the percentage allocations among distribution companies associated with the Allowed Claim (described herein) apply the percentages set forth in the NEP wholesale restructuring settlement agreements in Rhode Island, Massachusetts and New Hampshire. The Administrative Claim (described herein) is generally associated with the Wholesale Standard Offer Service Agreements ("WSOS Agreements") claims and thus the allocations associated with the Administrative Claim correlate to the distribution companies' costs under the respective WSOS Agreements.

(3) the Hydro Quebec Interconnection Transfer Agreement dated September 1, 1998 by and between NEP and USGenNE ("HQITA") relating to support for and use of the high-voltage direct current interconnection facilities from Canada; and

(4) the Amended and Restated Continuing Site/Interconnection Agreement dated September 1, 1998 by and between NEP and USGenNE ("CSA") relating to the joint use of and allocation of responsibilities for common or shared properties situated on site of the generation properties transferred from NEP to USGenNE.

In addition, the Settlement Agreement and Release approved by the Bankruptcy Court ("USGenNE Settlement") resolved any disputes between the National Grid Companies and USGenNE associated with the Mass. Electric Wholesale Standard Offer Service Agreement ("Mass. Electric WSOSA")[2] and the Narragansett Wholesale Standard Offer Service Agreement ("Narragansett WSOSA").[3]

WHEREAS, USGenNE made these commitments at the time that NEP sold its fossil and hydro generating units and transferred economic responsibility for power contracts and the Hydro Quebec intertie to USGenNE.

WHEREAS, On December 22, 2004, the Bankruptcy Court approved the USGenNE Settlement entered into as of December 9, 2004 by and among USGenNE and NEP, Narragansett, Mass. Electric, Granite State, National Grid USA Service Company, Inc., National Grid USA, and affiliated companies (collectively, "National Grid"). The USGenNE Settlement resolved all issues between National Grid and USGenNE associated with the USGenNE

[2] Second Amended and Restated Wholesale Standard Offer Service Agreement, dated September 1, 1998 between Mass. Electric and USGenNE.
[3] Second Amended and Restated Wholesale Standard Offer Service Agreement, dated September 1, 1998 between Narragansett and USGenNE.

bankruptcy. The USGenNE Settlement thus facilitated USGenNE's sale to third parties[4] of generating facilities which USGenNE had purchased from NEP and Narragansett. USGenNE's resale of these facilities has produced the proceeds that USGenNE used to pay the claims of NEP and its affiliates, together with those of other creditors

WHEREAS, on June 8, 2005, the National Grid Companies recovered $195,805,290 pursuant to terms of the USGenNE Settlement. Of this amount, $195 million was for the National Grid Companies' unsecured claim from USGenNE ("Allowed Claim") for the breach, rejection or termination of the APA, PPATA, HQITA and CSA, including any claims that NEP and its affiliates asserted or may have asserted for damages arising from the agreements. As provided for in the USGenNE Settlement, NEP received interest on $17 million of the Allowed Claim accruing from the period beginning April 1, 2004 and ending on the date that the claim was paid, June 8, 2005, which equated to $805,290.[5]

WHEREAS, pursuant to the formula for the CTC billable by NEP to Narragansett, under the NEP/Narragansett Electric T1 Service Agreement, the Allowed Claim is credited to the CTC when received and obligations returning to NEP as a result of the USGenNE breach, rejection of or termination of the APA, PPATA and HQITA is recovered through the CTC when incurred.

WHEREAS, the USGenNE Settlement provided for a $10 million payment to address the resolution of claims asserted or that may be asserted by the National Grid Companies against

[4] The purchasers of the plants are: Dominion Energy Brayton Point, LLC (Brayton Point Station), Dominion Energy Manchester Street, Inc. (Manchester Street Station), Dominion Energy Salem Harbor, LLC (Salem Harbor Station), TransCanada Hydro Northeast Inc. (the hydro facilities except Bear Swamp and Fife Brook which the owner-creditors of those facilities are transferred to Bear Swamp Power Company, a joint venture of Brascan Power Inc. and Emera Inc.). TransCanada Hydro Northeast Inc. has a contractual obligation with USGenNE to sell the Bellows Falls plant to the Town of Rockingham (or its assignee, the Vermont Hydro-electric Power Authority, collectively "Rockingham") upon the satisfaction by Rockingham of certain conditions. If transferred, Bellows Falls would be operated by Brascan Power and Emera Inc.

[5] The aggregate amount of the claim and interest is referred to herein as $195 million. National Grid proposes to allocate the $805,290 in interest in the same proportional manner as the proceeds associated with the Allowed Claim.

USGenNE under the Narragansett WSOSA, as well as under the Mass. Electric WSOSA (which by its terms expired December 31, 2004) and the First Amended and Restated Agreement for Temporary Implementation and Administration of Wholesale Standard Offer Service Agreements between USGenNE, Mass. Electric and Narragansett ("TIA"), effective March 1, 2003 through the date of the closing on the sale of USGenNE's fossil assets[6], (the "Administrative Claim[7]").

WHEREAS, the Parties have reviewed the CTC Mitigation Plan and concur with that plan's proposal (i) to allocate the Allowed Claim in accordance with the distribution companies' respective CTC obligations, and apply the proceeds in a way that will optimize the benefit to customers of the National Grid Companies, (ii) to update estimates for decommissioning and purchased power expenses included in the projected CTC and (iii) to implement a procedure for addressing and further mitigating future CTC costs associated with the returning obligations under the seven purchase power contracts[8] that were under the PPATA, which was rejected by USGenNE ("Returning PPAs"), and the payment obligations under the Hydro Quebec support agreements, and (iv) to specify the cost allocation for any costs arising from the rejected indemnification obligations under the APA.

WHEREAS, the Parties intend that customers receive the full value of the settled issues, and not some substitute regulatory treatment of lesser value, and agree that no terms of this Settlement or supporting schedules and calculations will be used or interpreted to diminish, in any way, the intended customer benefit related to this agreement.

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[6] The fossil sale was effective January 1, 2005.
[7] The Administrative Claim is defined as the National Grid Administrative Claim in the USGenNE Settlement.
[8] As a result of its rejection of the PPATA, seven contracts with remaining terms came back to NEP: (i) Milford Power; (ii) Wheelabrator Millbury; (iii) Wheelabrator Saugus; (iv) Lawrence Hydro; (v) Johnston Landfill (Ridgewood); (vi) Four Hills Landfill; and (vii) MWRA Cosgrove.

NOW THEREFORE, in consideration of the exchange of promises and covenants hereinafter contained, the Parties hereby agree to the following:

(1) NEP shall allocate $43.6 million, or 22.4 percent of the $195,805,000 Allowed Claim less $1,295,000 of pre-petition accounts receivables to Narragansett based upon its 22.4 percent share of NEP's CTC to pay down the unrecovered fixed assets of Montaup that are billable to Narragansett[9]. Because the asset balances being paid down were valued as of December 31, 2005, a credit associated with the return on those stranded costs is necessary to reflect the pay down of those assets as of June 8, 2005, when the payment for the Allowed Claim was actually received by NEP from USGenNE. To accomplish this return adjustment, NEP shall credit the CTC reconciliation account for Narragansett by $1.8 million in December 2005, representing the return on the allocated Allowed Claim for the period June 8, 2005 through December 31, 2005. The calculation of this interest amount is detailed on Attachment 1.

(2) NEP shall allocate to Narragansett 22.4 percent of any and all liabilities and obligations related to the rejection of the PPATA, HQITA, and APA indemnification obligation, pursuant to the June 21, 2005 CTC Mitigation Plan submitted by National Grid, net of any market revenue related to entitlements received under the agreements that formed the PPATA and HQITA contracts.

(3) NEP shall implement the revised Schedules 1 and 2 to Appendix 1 of the NEP/Narragansett T1 Service Agreement included in Attachment 2 to this Settlement, effective January 1, 2006. The revised schedules reflect the credits set forth in paragraph (2)(A)-(C),

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[9] Based on the current CTC rate projection, as provided in the November 24, 2004 CTC Reconciliation Reports, Montaup's unrecovered fixed assets billable to Narragansett amount to $69 million at December 31, 2005. As a result of the May 2000 merger of the former New England Electric System ("NEES") and Eastern Utilities Associates ("EUA"), the former EUA wholesale company, Montaup, was merged into NEP and EUA's former Rhode Island distribution subsidiaries, Blackstone Valley Electric Company ("Blackstone") and Newport Electric Corporation ("Newport"), were merged into Narragansett. Consequently, since May 2000, NEP's CTC to Narragansett has included Montaup charges related to the former Blackstone and Newport.

together with updated estimated decommissioning and purchased power expenses in its projected CTC calculations reflecting the latest estimates of decommissioning costs for the Yankee Nuclear units and estimated purchased power costs associated with returning obligations from the rejected PPATA and HQITA (net of estimated market revenue from the sale of entitlements from the underlying contracts). Prior to December 31, 2005 any such net costs will be included in NEP's CTC reconciliation account

(4) Upon approval of this Settlement, NEP shall implement a stakeholder process among the three effected states prior to taking action to restructure, terminate, assign or transfer the Returning PPAs to one or more third parties in a manner which mitigates risks or provides a fixed and/or known cost for each Returning PPA.[10]

(5) Consideration of the possible inclusion of the cost of some or all of the Hydro Quebec facilities in regional transmission rates was initiated in the context of the New England Regional Transmission Organization formation. To the extent the costs of the Hydro Quebec facilities are rolled-in to a regional transmission rate, some or all of the monthly costs may be paid by regional transmission customers and these costs will be eliminated from the CTC.

(6) The $10 million associated with the Administrative Claim shall be allocated to Narragansett.

(7) This Settlement is expressly conditioned upon the Commission's acceptance of all provisions hereof, without change or condition, and in the event that the Commission does not by

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[10] Effective April 1, 2005, NEP began reselling the power it receives from each Returning PPAs into the NEPOOL spot markets and crediting any revenues received toward expenses incurred under the Returning PPAs. To the extent possible, NEP will sell any capacity associated with the Returning PPAs in the bilateral market on a monthly basis. Any capacity not sold in the bilateral market will be made available in the ISO-New England administered Capacity Supply Auction and Capacity Deficiency Auction. All capacity revenues received will be credited toward expenses incurred under the Returning PPAs. Since USGenNE's rejection of the HQITA in April 2004, NEP has posted, and will continue to post, the availability of the transmission capacity related to the facilities associated with the HQITA on the OASIS. Such postings have been made for the 4% entitlement formerly held by Montaup, and since April 2, 2004, for the 18% entitlement covered by the HQITA which was rejected by USGenNE.

order accept this Settlement in its entirety, this Settlement shall be deemed withdrawn and shall not constitute any part of the record in this proceeding or be used for any other purpose, and each of its provisions shall be deemed to be null and void.

(8) Except as set forth in this Settlement, the making of this Settlement shall not be deemed in any respect to constitute an admission by any party that any allegation or contention in this proceeding is true and valid.

(9) Except as specifically set forth in this Settlement as necessary to accomplish the customer benefit intended by this Settlement, the Commission's approval of this Settlement shall not constitute approval of, or precedent regarding any principle or issue in this proceeding.

(10) The discussions which have produced this Settlement have been conducted on the explicit understanding, pursuant to Rule 602(3) of the Commission's Rules of Practice and Procedure, that all offers of settlement and discussions relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussions and are not to be used in any manner in connection with these or any other proceedings.

Respectfully submitted,

NARRAGANSETT ELECTRIC COMPANY AND
NEW ENGLAND POWER COMPANY

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November 14, 2005

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SETTLEMENT AGREEMENT ATTACHMENTS

Attachment 1	Calculation of interest on the Allowed Claim for the period June 8, 2005 through December 31, 2005
Attachment 2	Revised Schedule 1 and Revised Schedule 2 to the NEP/Narragansett T1 Service Agreement

SETTLEMENT AGREEMENT ATTACHMENT 1

New England Power Company
Calculation of 2005 Interest on Settlement Proceeds Included in Blackstone and Newport Reconciliation Accounts
Rhode Island
(in Thousands)

	Montaup Fixed Assets
Application of R.I. Allocation of Total Settlement Proceeds	43,570
After-tax return Rate /1	7.39%
Interest from June 8 through December 31, 2005	1,818
Retail Company responsibility share	40.98%
Interest Credit included in Blackstone and Newport Reconcil Acct. in Dec.'05	4,435

/1 Total R.I. CTC return rate of 12.16% times 60.775%.

SETTLEMENT AGREEMENT ATTACHMENT 2

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Narragansett Electric Company CTC Calculation

New England Power Company
Summary of Contract Termination Charges
to The Narragansett Electric Company

POST-DIVESTITURE
2004 CTC Reconciliation

Line	Year	Estimated Narragansett Electric Company Gwh Delivered	Portion of the Year for Retail Access	Estimated Narragansett Electric Company Gwh Delivered for Portion of the Year	Share of Fixed Component		Share of Variable Component		Share of Total Termination Charge	TOTAL CTC EXPENSES: Contract Termination Charge	Less Prepayment & Lump Sum Payment	Adjusted CTC	
					$ in Millions	cents/kwh	$ in Millions	cents/kwh	$ in Millions	**cents/kwh**	$ in Millions	$ in Millions	cents/kwh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
(1)	**1998**	**1,626**	**100%**	**1,626**	**5.4**	**0.33**	**19.0**	**1.17**	**24.4**	**1.50**			
(2)	**1999**	**5,013**	**100%**	**5,013**	**38.8**	**0.77**	**40.5**	**0.81**	**79.2**	**1.58**	**21.4**	**57.8**	**1.15**
(3)	**2000**	**5,165**	**100%**	**5,165**	**9.9**	**0.19**	**49.7**	**0.96**	**59.6**	**1.15**	**17.5**	**42.1**	**0.82**
(4)	**2001**	**5,183**	**100%**	**5,183**	**1.4**	**0.03**	**40.2**	**0.78**	**41.5**	**0.80**	**5.0**	**N/A**	**N/A**
(5)	**2002**	**5,232**	**100%**	**5,232**	**1.3**	**0.02**	**33.8**	**0.65**	**35.1**	**0.67**			
(6)	January	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(7)	February	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(8)	March	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(9)	April	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(10)	May	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(11)	June	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(12)	July	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(13)	August	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(14)	September	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(15)	October	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(16)	November	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(17)	December	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(18)	**2003**	**5,288**	**100%**	**5,288**	**1.2**	**0.02**	**34.9**	**0.66**	**36.1**	**0.68**			
(19)	January	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(20)	February	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(21)	March	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(22)	April	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(23)	May	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(24)	June	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(25)	July	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(26)	August	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(27)	September	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(28)	October	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(29)	November	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(30)	December	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(31)	**2004**	**5,356**	**100%**	**5,356**	**1.1**	**0.02**	**32.5**	**0.61**	**33.7**	**0.63**			
(32)	2005	5,428	100%	5,428	1	0.02	35	0.65	36	**0.67**			
(33)	2006	5,496	100%	5,496	1	0.02	35	0.64	36	**0.66**			
(34)	2007	5,562	100%	5,562	1	0.02	21	0.38	22	**0.40**			
(35)	2008	5,628	100%	5,628	1	0.02	23	0.40	23	**0.42**			
(36)	2009	5,695	100%	5,695	1	0.01	17	0.30	18	**0.31**			
(37)	2010	5,783	100%	5,783			14	0.24	14	**0.24**			
(38)	2011	5,864	100%	5,864			9	0.15	9	**0.15**			
(39)	2012	5,946	100%	5,946			9	0.15	9	**0.15**			
(40)	2013	6,029	100%	6,029			9	0.14	9	**0.14**			
(41)	2014	6,114	100%	6,114			8	0.13	8	**0.13**			
(42)	2015	6,199	100%	6,199			8	0.12	8	**0.12**			
(43)	2016	6,286	100%	6,286			6	0.09	6	**0.09**			
(44)	2017	6,374	100%	6,374			4	0.07	4	**0.07**			
(45)	2018	6,463	100%	6,463			1	0.02	1	**0.02**			
(46)	2019	6,554	100%	6,554			1	0.01	1	**0.01**			
(47)	2020	6,646	100%	6,646			0	0.00	0	**0.00**			
(48)	2021	6,739	100%	6,739			0	0.00	0	**0.00**			
(49)	2022	6,833	100%	6,833			0	0.00	0	**0.00**			
(50)	2023	6,929	100%	6,929			0	0.00	0	**0.00**			
(51)	2024	7,026	100%	7,026			0	0.00	0	**0.00**			
(52)	2025	7,124	100%	7,124			0	0.00	0	**0.00**			
(53)	2026	7,224	100%	7,224			0	0.00	0	**0.00**			
(54)	2027	7,325	100%	7,325			0	0.00	0	**0.00**			
(55)	2028	7,427	100%	7,427			0	0.00	0	**0.00**			
(56)	2029	7,531	100%	7,531			0	0.00	0	**0.00**			

Column Notes:
(1) Annual totals for 1998-2002 Reconciliations, monthly for 2003-2004; annual thereafter.
(2) Per June 3, 1996 Integrated Least Cost Plan Update. Includes incremental DSM.
(3) Per Utility Restructuring Act of 1996, pages 24 and 25. Assumes 100% Retail Access as of 1/1/98.
(4) Column (2) x Column (3).
(5) See Schedule 1, Page 2, Column (7).
(6) Column (5)/Column (4) x 100.
(7) See Schedule 1, Page 3, Column (18).
(8) Column (7)/Column (4) x 100.
(9) Column (5) + Column (7).
(10) Column (9) / Column (4) x 100.
(11) The $5 million payment was paid to Narragansett in December 2000 to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.

New England Power Company
Summary of Contract Termination Charges
The Narragansett Electric Company Share (22.4%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	**1998**	**11.3**	**45.3**		**0.3**	**56.9**	**(51.4)**	**5.4**
(2)	**1999**	**23.9**	**146.6**	**21.4**	**1.2**	**193.1**	**(154.3)**	**38.8**
(3)	**2000**	**11.9**	**151.1**		**1.2**	**164.2**	**(154.3)**	**9.9**
(4)	**2001**	**5.5**	**0.0**		**1.1**	**6.6**	**(5.3)**	**1.4**
(5)	**2002**	**5.0**	**0.0**		**1.1**	**6.1**	**(4.8)**	**1.3**
(6)	January	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(7)	February	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(8)	March	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(9)	April	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(10)	May	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(11)	June	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(12)	July	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(13)	August	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(14)	September	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(15)	October	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(16)	November	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(17)	December	0.4	0.0		0.1	0.5	(0.4)	**0.1**
(18)	**2003**	**4.6**	**0.0**		**1.0**	**5.6**	**(4.4)**	**1.2**
(19)	January	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(20)	February	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(21)	March	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(22)	April	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(23)	May	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(24)	June	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(25)	July	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(26)	August	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(27)	September	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(28)	October	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(29)	November	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(30)	December	0.3	0.0		0.1	0.4	(0.3)	**0.1**
(31)	**2004**	**4.2**	**0.0**		**1.0**	**5.1**	**(4.0)**	**1.1**
(32)	2005	4	0		1	**5**	(4)	**1**
(33)	2006	3	0		1	**4**	(3)	**1**
(34)	2007	3	0		1	**4**	(3)	**1**
(35)	2008	3	0		1	**3**	(2)	**1**
(36)	2009	2	0		1	**3**	(2)	**1**
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
Columns (2) through (5) represent 22.4% of the same Column number on Schedule 1, Page 12.
(7) Column (5) + Column (6).

New England Power Company
Summary of Contract Termination Charges

The Narragansett Electric Company Share (22.4%)
Variable Component
$ in Millions

Line	Year End (1)	Nuclear Decommissioning and Other Post-Shutdown Costs (2)	Power Contracts: Power Total Obligation (3)	Power Contracts: Assumed Market Value (4)	Power Contracts: Net: Excess Over Market (5)	Future Power Contract Buyouts (6)	Credit for Unit Sales Contracts: Power Total Obligation (7)	Credit for Unit Sales Contracts: Assumed Market Value (8)	Credit for Unit Sales Contracts: Net: Excess Over Market (9)	Above Market Fuel Transportation Costs (10)	Transmission in Support of Remote Generating Units (11)	Payments in Lieu of Property Taxes (12)	Employee Severance and Retraining Costs (13)	Damages, Costs, or Net Recoveries from Claims (14)	PBR for Nuclear Units Remaining After Market Valuation (15)	**Base Total Variable Component (16)**	Reconciliation Account (17)	**Total Variable Component Including Reconciliation Account (18)**
(1)	**1998**	**5.3**	**0.0**	**0.0**	**0.0**	**13.6**	**(0.5)**	**(0.4)**	**(0.1)**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**19.0**	**0.0**	**19.0**
(2)	**1999**	**12.5**	**0.0**	**0.0**	**0.0**	**40.8**	**(1.7)**	**(1.2)**	**(0.5)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.1**	**(12.6)**	**40.5**
(3)	**2000**	**10.6**	**0.0**	**0.0**	**0.0**	**40.7**	**(1.6)**	**(1.2)**	**(0.4)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**51.2**	**(1.5)**	**49.7**
(4)	**2001**	**12.7**	**0.0**	**0.0**	**0.0**	**40.5**	**(0.4)**	**(0.2)**	**(0.2)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.3**	**(13.1)**	**40.2**
(5)	**2002**	**10.1**	**0.0**	**0.0**	**0.0**	**40.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**50.5**	**(16.6)**	**33.8**
(6)	January	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(7)	February	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(8)	March	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(9)	April	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(10)	May	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(11)	June	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(12)	July	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(13)	August	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(14)	September	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(15)	October	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(16)	November	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(17)	December	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(18)	**2003**	**6.3**	**0.0**	**0.0**	**0.0**	**37.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**43.7**	**(8.8)**	**34.9**
(19)	January	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(20)	February	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(21)	March	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(22)	April	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(23)	May	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(24)	June	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(25)	July	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(26)	August	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(27)	September	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(28)	October	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(29)	November	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(30)	December	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(31)	**2004**	**6.5**	**0.0**	**0.0**	**0.0**	**35.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**42.1**	**(9.6)**	**32.5**
(32)	2005	6	23	13	9	26	0	0	0	0	0	0	0	0	0	**42**	(7)	**35**
(33)	2006	8	28	16	11	22	0	0	0	0	0	0	0	(4)	0	**37**	(2)	**35**
(34)	2007	7	28	15	12	2	0	0	0	0	0	0	0	0	0	**21**	0	**21**
(35)	2008	6	27	12	15	1	0	0	0	0	0	0	0	0	0	**22**	0	**23**
(36)	2009	5	19	9	10	1	0	0	0	0	0	0	0	0	0	**17**	0	**17**
(37)	2010	5	17	9	9	0	0	0	0	0	0	0	0	0	0	**14**	0	**14**
(38)	2011	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(39)	2012	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	1	**9**
(40)	2013	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(41)	2014	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(42)	2015	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(43)	2016	0	11	5	6	0	0	0	0	0	0	0	0	0	0	**6**	(0)	**6**
(44)	2017	0	9	4	4	0	0	0	0	0	0	0	0	0	0	**4**	(0)	**4**
(45)	2018	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(46)	2019	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(47)	2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**

Column Notes:

Columns (2) through (16) represent 22.4% of the same Column number on Schedule 1, Page 15.
(17) See Schedule 2, Page 3, Column (6) x -1
(18) Column (16) + Column (17)

NO ADJUSTMENTS

New England Power Company's Generation Facilities
Net Capability and Unrecovered Costs
Based Upon Actuals

Source	Location	Year(s) Placed In-Service	Energy Source	Net Capability (MW)	$ Millions 1995		$ Millions Sept 1, 1998 *		Applicable Annual Depreciation per W-95 (S) for the period: 1997	1998 and Beyond	
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)	(9)	
Fossil Fuel Units											
Brayton Point Station											
Units 1,2 & 3	Somerset,	1963-1969	Coal-Oil-Gas	1,130							
Unit 4	Mass.	1974	Oil-Gas	446							
				1,576							
Salem Harbor Station											
Units 1,2 & 3	Salem,	1952-1958	Coal-Oil	314							
Unit 4	Mass.	1972	Oil	400							
				714							
Other System Units	Me., Mass.	1963-1978	Oil	101							
Subtotal Brayton Point, Salem Harbor, and Other				2,391	$435		$353		$34.2	$34.2	(c)
Manchester St. Station	Prov., R.I.	1995	Oil-Gas	513	460	(a)	400	(a)	17.1	17.1	(d)
Hydroelectric Units											
Conventional	Mass., N.H. & Vt.	1909-1987	Water	577	169		150		3.7	3.7	
Pumped Storage Bear Swamp	Rowe, Mass.	1974	Water	589	73		65		1.8	1.8	
Nuclear Units											
Vermont Yankee	Vermont	1972	Nuclear	341	73	(b)	27	(b)	6.2	6.2	(e)
Millstone 3	Waterford, Conn.	1986	Nuclear	140	390	(b)	338	(b)	30.0	44.9	(f)
Seabrook 1	Seabrook, N.H.	1990	Nuclear	115	63	(b)	41	(b)	1.9	1.9	
Step-Up Transformers at Generation Facilities (Not Included in Transmission Rates)					12		10		0.4	0.4	
General Plant Allocated to Generation					10		8		0.3	0.3	
Generation Related Property Held For Future Use and Non-Utility Property					11		10		0.0	0.0	
Nantucket Generating Units (Not included in Transmission Rates)					0		0		0.0	0.0	
Total				**4,666**	**$1,695**		**$1,404**		**$95.6**	**$110.5**	

Notes:
(a) Includes prepaid taxes in accordance with tax treaty.
(b) Includes balances for final fuel core and materials and supplies.
(c) Depreciation includes dismantlement expense of $5 M and $3 M for Brayton Point and Salem Harbor, respectively, through the year 2004.
(d) Includes $3.3 M of annual amortization of prepaid taxes which ends 2002.
(e) Depreciation based upon years remaining under license. Vermont Yankee license expires 2012.
(f) Millstone 3 base amortization was adjusted for acceleration per W-95S in 1996 and 1997. Accelerated amortization for 1998. is as noted in the table and an additional $1.2 M of amortization should be added each year thereafter until fully depreciated.

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company Generation Related
Regulatory Asset Balances
$ in Millions

	Balance as of December 31, 1995	Balance as of Sept 1, 1998 *	Applicable Annual Depreciation per W-95 (S) for the period: 1997	Applicable Annual Depreciation per W-95 (S) for the period: 1998 and Beyond	Basis for Deferral
	(1)	(2)	(3)	(4)	(5)
FAS 109	$28	$21	0.9	0.9	FERC Ratemaking Policy
Unamortized Losses on Reacquired Debt	26	23	1.8	1.8	FERC Ratemaking Policy
Pipeline Demand Charges	58	49	2.3	2.3	Settlement Agreement (1)
NEEI	226	130	18.0	21.2	Settlement Agreement (2)
FAS 106 Deferral	13	1	11.0	0.0	FERC Ratemaking Policy
Power Contract Buyouts	24	16	3.9	3.9	Settlement Agreement (3)
Property Losses	5	0	0.0	0.0	Settlement Agreement (2)
Rate Clauses	5	3	0.7	0.7	Settlement Agreement (4)
South Street Cost of Removal	8	2	3.9	0.0	Settlement Agreement (3)
Brayton Point Rotor	9	2	4.2	0.0	Settlement Agreement (3)
Seabrook Tax True-Up	2	2	0.0	0.0	Settlement Agreement (2)
Decontamination & Decommissioning Costs	2	3	0.2	0.2	FERC Ratemaking Policy
W-95S Adjustment Account	2	(10)	0.3	0.0	Settlement Agreement (3)
Unamortized ITC	(23)	(21)	(1.2)	(1.2)	FERC Ratemaking Policy
Total Regulatory Assets	**$384**	**$222**	**$46.0**	**$29.9**	

Settlement Agreement Notes:

(1) W-92 Settlement Agreement - FERC Docket Nos. ER91-565-000 and ER91-566-000
(2) W-9 Settlement Agreement - FERC Docket No. ER88-86-000
(3) W-95 Settlement Agreement - FERC Docket Nos. ER95-267-000
(4) Surcharge Compliance Filing Settlement, FERC Docket Nos. ER88-630-000 et al. (Rate W-10), ER89-582-000 et al. (Rate W-11), and ER90-525-000 et al. (Rate W-12)

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company

FAS 106 Transition Obligation Regulatory Asset

$ in Millions

Unrecovered Balance as of 9/1/98 per Pre-Divestiture	$61.5	
Less: Unrecognized Gain/(Loss) Allocated to Generation	25.4	(a)
Unrecovered Balance as of 9/1/98	**$36.1**	
Actuarial Discount Rate	6.75%	
Amortization (straightline)	11.3	years

Line		Amortization (1)	Interest (2)	Total Expense (3)	Unamortized Balance (4)
(1)	**Unrecovered Balance as of 9/1/98**				**36.1**
(2)	**1998**	**1.1**	**2.4**	**3.5**	**35.1**
(3)	**1999**	**3.2**	**2.3**	**5.4**	**31.9**
(4)	**2000**	**3.2**	**2.0**	**5.2**	**28.7**
(5)	**2001**	**3.2**	**1.8**	**5.0**	**25.5**
(6)	**2002**	**3.2**	**1.6**	**4.8**	**22.3**
(7)	**2003**	**3.2**	**1.4**	**4.6**	**19.1**
(8)	**2004**	**3.2**	**1.2**	**4.4**	**15.9**
(9)	2005	3.2	1.0	**4.2**	12.8
(10)	2006	3.2	0.8	**3.9**	9.6
(11)	2007	3.2	0.5	**3.7**	6.4
(12)	2008	3.2	0.3	**3.5**	3.2
(13)	2009	3.2	0.1	**3.3**	0.0
		36.1			

Column Notes:
(1) Column (4), line (1)/11.33.
(2) (Prior year Column (4) + Current year Column (4))/2 x .0675
(3) Column (1) + Column (2).
(4) Prior year Column (4) - Column (1).

New England Power Company Share of Total Nuclear Post-Shutdown Costs

Based Upon Original Estimates

$ in Millions

	Millstone 3 (1)	**Seabrook 1** (2)	**Vermont Yankee** (3)	**Total** (4)
1998	0	0	0	**0**
1999	0	0	0	**0**
2000	0	0	0	**0**
2001	7	6	7	**20**
2002	0	6	7	**13**
2003	0	0	0	**0**
2004	0	0	0	**0**
2005	0	0	0	**0**
2006	0	0	0	**0**
2007	0	0	0	**0**
2008	0	0	0	**0**
2009	0	0	0	**0**
2010	0	0	0	**0**
2011	0	0	0	**0**
2012	0	0	0	**0**
2013	0	0	0	**0**
2014	0	0	0	**0**
2015	0	0	0	**0**
2016	0	0	0	**0**
2017	0	0	0	**0**
2018	0	0	0	**0**
2019	0	0	0	**0**
2020	0	0	0	**0**
2021	0	0	0	**0**
2022	0	0	0	**0**
2023	0	0	0	**0**
2024	0	0	0	**0**
2025	0	0	0	**0**
2026	0	0	0	**0**
2027	0	0	0	**0**
2028	0	0	0	**0**
2029	0	0	0	**0**

Column Notes:
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(3) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

New England Power Company Share of Total Annual Decommissioning Cost

Based Upon Revised Estimates

$ in Millions

	Millstone 3 (1)	Seabrook 1 (2)	Connecticut Yankee (3)	Vermont Yankee (4)	Maine Yankee **(5)**	Yankee Atomic (6)	Total Nuclear Decommissioning (7)
Sept 1, 1998	0	0	8	1	9	5	**24**
1999	1	1	17	2	19	15	**56**
2000	2	2	16	3	17	8	**48**
2001	2	2	15	3	16	0	**37**
2002	0	2	13	3	14	0	**32**
2003	0	0	13	0	15	0	**28**
2004	0	0	13	0	16	0	**29**
2005	0	0	13	0	16	0	**29**
2006	0	0	19	0	12	4	**35**
2007	0	0	17	0	12	4	**32**
2008	0	0	14	0	10	4	**28**
2009	0	0	14	0	7	4	**25**
2010	0	0	14	0	6	4	**24**
2011	0	0	0	0	0	0	**0**
2012	0	0	0	0	0	0	**0**
2013	0	0	0	0	0	0	**0**
2014	0	0	0	0	0	0	**0**
2015	0	0	0	0	0	0	**0**
2016	0	0	0	0	0	0	**0**
2017	0	0	0	0	0	0	**0**
2018	0	0	0	0	0	0	**0**
2019	0	0	0	0	0	0	**0**
2020	0	0	0	0	0	0	**0**
2021	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	**0**

Column Notes
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(4) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

Columns (3), (5), and (6) reflect permanent shutdown of Connecticut Yankee, Maine Yankee, and Yankee Atomic units and thus include both post-shutdown and decommissioning costs.

Power Contract Buyout Payments Associated with Divestiture
Per IPP Transfer Agreement

$ Millions

	Milford Power	Ridgewood	Resco Saugus	Wheelabrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	Total
2005	34.7	5.5	16.8	26.6	3.3	0.1	0.1	14.0	101.1
2006	40.1	7.7	22.8	35.1	4.3		0.2	13.5	123.7
2007	40.0	7.8	23.2	35.7	4.2		0.0	12.3	123.2
2008	37.2	8.0	23.6	36.4	4.0			11.6	120.7
2009	2.7	8.2	24.0	37.0	3.8			11.2	86.9
2010		0.7	24.4	37.7	3.7			10.9	77.4
2011			24.8	38.4	3.5			10.6	77.3
2012			24.2	39.2				10.3	73.7
2013			25.7	39.9				10.0	75.6
2014			26.1	40.7				9.7	76.5
2015			26.6	41.5				7.5	75.6
2016				42.3				6.4	48.8
2017				31.9				6.2	38.1
2018								6.0	6.0
2019								5.0	5.0
2020								1.2	1.2

Power Contract Obligations
Estimated Market Value

Based Upon Revised Estimates

$'s in millions

	Milford Power	Ridgewood	Resco Saugus	Wheelebrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	TOTAL
2005	13.2	5.7	14.6	21.0	4.2	0.0	0.1	1.4	**60.2**
2006	10.4	8.2	19.6	26.5	6.2		0.3	1.3	**72.4**
2007	10.6	7.6	18.6	24.9	5.8		0.0	1.2	**68.7**
2008	8.8	5.9	14.8	19.4	4.7			1.2	**54.8**
2009	0.2	5.3	13.4	17.4	4.2			1.1	**41.6**
2010		0.5	14.2	18.5	4.4			1.1	**38.8**
2011			14.7	19.1	4.6			1.1	**39.4**
2012			15.4	20.0				1.0	**36.4**
2013			16.0	20.7				1.0	**37.7**
2014			16.9	22.1				1.0	**40.0**
2015			17.6	22.9				0.8	**41.2**
2016				23.2				0.6	**23.9**
2017				17.7				0.6	**18.3**
2018								0.6	**0.6**
2019								0.5	**0.5**
2020								0.1	**0.1**

New England Power Company
Annual Utility Unit Sales Power Contracts

Based Upon Original Estimates

$ in Millions

	OSP	Maine Yankee	Millstone 3	Millstone3/ Seabrook 1	**TOTAL**
	(1)	(2)	(3)	(4)	(5)
1997	5	0	1	5	**12**
1998	0	1	1	5	**7**
1999	0	0	1	6	**8**
2000	0	1	1	6	**7**
2001	0	1	1		**2**
2002	0	0	0		**0**
2003	0	0	0		**0**
2004	0	0	0		**0**
2005	0	0	0		**0**
2006	0	0	0		**0**
2007	0				**0**
2008	0				**0**
2009	0				**0**
2010	0				**0**

Column Notes:

Estimates have been set to zero. Actual unit sales are reflected in the Nuclear PBR.

NO ADJUSTMENTS

New England Power Company
Fixed Costs of Gas Transportation
Contractual Commitments

Based Upon Original Estimates

Annual Expenses

$ in Millions

	Total Pipeline Demand Charge Obligation (1)	Assumed by USGen NE (2)	Excess (3)	Total Energy Enterprise Minimum Payments (4)	Assumed by USGen NE (5)	Excess (6)	**Total Above Market Fuel Transportation Costs (7)**
Sept 1, 1998	31	31	0	6	6	0	**0**
1999	60	60	0	13	13	0	**0**
2000	60	60	0	13	13	0	**0**
2001	59	59	0	14	14	0	**0**
2002	58	58	0	14	14	0	**0**
2003	57	57	0	15	15	0	**0**
2004	56	56	0	13	13	0	**0**
2005	55	55	0	14	14	0	**0**
2006	54	54	0	14	14	0	**0**
2007	41	41	0	14	14	0	**0**
2008	40	40	0	15	15	0	**0**
2009	35	35	0	15	15	0	**0**
2010	35	35	0	16	16	0	**0**
2011	34	34	0	1	1	0	**0**
2012	30	30	0	0	0	0	**0**
2013	29	29	0	0	0	0	**0**
2014	16	16	0	0	0	0	**0**

Columns Notes:

(2) All payments assumed by USGen NE.
(3) Column (1) - Column (2).
(5) All payments assumed by USGen NE.
(6) Column (4) - Column (5).
(7) Column (3) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges

New England Power Company (100%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	**1998**	**50.5**	**202.2**		**1.2**	**253.8**	**NA**	**253.8**
(2)	**1999**	**106.6**	**654.0**	**95.5**	**5.4**	**861.5**	**NA**	**861.5**
(3)	**2000**	**53.1**	**674.3**		**5.2**	**732.6**	**NA**	**732.6**
(4)	**2001**	**24.5**	0.0		**5.0**	**29.6**	**NA**	**29.6**
(5)	**2002**	**22.4**	0.0		**4.8**	**27.2**	**NA**	**27.2**
(6)	January	1.7	0.0		0.4	**2.1**	NA	**2.1**
(7)	February	1.7	0.0		0.4	**2.1**	NA	**2.1**
(8)	March	1.7	0.0		0.4	**2.1**	NA	**2.1**
(9)	April	1.7	0.0		0.4	**2.1**	NA	**2.1**
(10)	May	1.7	0.0		0.4	**2.1**	NA	**2.1**
(11)	June	1.7	0.0		0.4	**2.1**	NA	**2.1**
(12)	July	1.7	0.0		0.4	**2.1**	NA	**2.1**
(13)	August	1.7	0.0		0.4	**2.1**	NA	**2.1**
(14)	September	1.7	0.0		0.4	**2.1**	NA	**2.1**
(15)	October	1.7	0.0		0.4	**2.1**	NA	**2.1**
(16)	November	1.7	0.0		0.4	**2.1**	NA	**2.1**
(17)	December	1.7	0.0		0.4	**2.1**	NA	**2.1**
(18)	**2003**	**20.4**	**0.0**		**4.6**	**25.0**	**NA**	**25.0**
(19)	January	1.5	0.0		0.4	**1.9**	NA	**1.9**
(20)	February	1.5	0.0		0.4	**1.9**	NA	**1.9**
(21)	March	1.5	0.0		0.4	**1.9**	NA	**1.9**
(22)	April	1.5	0.0		0.4	**1.9**	NA	**1.9**
(23)	May	1.5	0.0		0.4	**1.9**	NA	**1.9**
(24)	June	1.5	0.0		0.4	**1.9**	NA	**1.9**
(25)	July	1.5	0.0		0.4	**1.9**	NA	**1.9**
(26)	August	1.5	0.0		0.4	**1.9**	NA	**1.9**
(27)	September	1.5	0.0		0.4	**1.9**	NA	**1.9**
(28)	October	1.5	0.0		0.4	**1.9**	NA	**1.9**
(29)	November	1.5	0.0		0.4	**1.9**	NA	**1.9**
(30)	December	1.5	0.0		0.4	**1.9**	NA	**1.9**
(31)	**2004**	**18.5**	**0.0**		**4.4**	**22.9**	**NA**	**22.9**
(32)	2005	17	0		4	**21**	NA	**21**
(33)	2006	15	0		4	**19**	NA	**19**
(34)	2007	13	0		4	**17**	NA	**17**
(35)	2008	11	0		4	**15**	NA	**15**
(36)	2009	9	0		3	**13**	NA	**13**
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
(1) Annual totals for 1998 - 2002 Reconciliations, monthly for 2003-2004; annual thereafter
(2) See Schedule 1, Page 14, Column (9).
(3) For years 1998-1999 Column (3) = [Schedule 1, Page 1, Column (10) x Schedule 1, Page 1, Column (4)]/100/.224 - Schedule 1, Page 15, Column (16) - Schedule 1, Page 12, Columns (2) and (4).
For 2000, Column (3) = Page 14, Column (2).
(4) Schedule 1, Page 5a, Column (3) x Page 1, Column (3).
(5) Sum of Columns (2) through (4).
(6) Not applicable at NEP level. See Schedule 1, Page 2, Column (6) for Narragansett Residual Value Credit.
(7) Column (5) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Deferred Taxes on Fixed Component

$ in Millions

		Book Basis			Tax Basis				
Line	Year End (1)	Balance Net Book Value of Generation (2)	Balance Generation Related Regulatory Assets (3)	Total Net Book Basis (4)	Balance Net Book Value of Generation (5)	Balance Generation Related Regulatory Assets (6)	**Total Tax Basis** (7)	**Excess Book Over Tax (8)**	**Deferred Taxes (9)**
Pre-Divest End Balances		**$1,435**	**$202**	**$1,636**	**$696**				
Less: Maine Yankee and ITC		31	(20)	10	14				
Post-Divest Start Balances		$1,404	$222	$1,626	$682				
(1)	**Sept 1, 1998**	**1,404**	**222**	**1,626**	**682**	**0**	**682**	**944**	**370**
(2)	**1998**	**1,229**	**195**	**1,424**	**652**	**0**	**652**	**771**	**303**
(3)	**1999**	**582**	**92**	**674**	**571**	**0**	**571**	**103**	**40**
(4)	**2000**	**0**	**0**	**0**	**521**	**0**	**521**	**(521)**	**(204)**
(5)	**2001**	**0**	**0**	**0**	**475**	**0**	**475**	**(475)**	**(186)**
(6)	**2002**	**0**	**0**	**0**	**433**	**0**	**433**	**(433)**	**(170)**
(7)	**2003**	**0**	**0**	**0**	**395**	**0**	**395**	**(395)**	**(155)**
(8)	**2004**	**0**	**0**	**0**	**357**	**0**	**357**	**(357)**	**(140)**
(9)	2005	0	0	0	320	0	**320**	**(320)**	**(125)**
(10)	2006	0	0	0	282	0	**282**	**(282)**	**(111)**
(11)	2007	0	0	0	246	0	**246**	**(246)**	**(96)**
(12)	2008	0	0	0	209	0	**209**	**(209)**	**(82)**
(13)	2009	0	0	0	175	0	**175**	**(175)**	**(69)**

Column Notes:
- (2) See Pre-Divestiture Schedule 1, for August 31,1998 balances. For year end 1997-2009, Column (2) prior year - (Schedule 1, Page 12, Column (3) current year x (Column (2) Line1/Column (4) Line 1).
- (3) See Pre-Divestiture Schedule 1, for August 31,1988 balances. For year end 1997-2009, Column (3) prior year-(Schedule 1, Page 12, Column (3) current year x (Column (3) Line1/Column (4) Line 1).
- (4) Column (2) + Column (3).
- (5) Per tax records of the Company.
- (6) Per tax records of the Company.
- (7) Column (5) + Column (6).
- (8) Column (4) - Column (7).
- (9) Column (8) x tax rate of .39225.

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Return on Fixed Component

		Base Return							
Line	Year End (1)	Balance of Fixed Component (2)	Deferred Taxes (3)	Net Balance (4)	Average Net Balance (5)	Subtotal Annual Return on Unamortized Balance (6)	Less: Return on Rate Clauses (7)	Plus: Return on Unamortized ITC (8)	Total Annual Return on Unamortized Balance (9)
(1)	Sept 1, 1998	$1,626	$370	$1,256					
(2)	**1998**	**1,424**	**303**	**1,121**	**$1,188**	**$50**	**($0.1)**	**$0.8**	**$50**
(3)	**1999**	**674**	**40**	**634**	**837**	**105**	**(0.1)**	**1.6**	**107**
(4)	**2000**	**0**	**(204)**	**204**	**419**	**53**	**(0.0)**	**0.5**	**53**
(5)	**2001**	**0**	**(186)**	**186**	**195**	**25**	**0.0**	**0.0**	**25**
(6)	**2002**	**0**	**(170)**	**170**	**178**	**22**	**0.0**	**0.0**	**22**
(7)	**2003**	**0**	**(155)**	**155**	**162**	**20**	**0.0**	**0.0**	**20**
(8)	**2004**	**0**	**(140)**	**140**	**148**	**19**	**0.0**	**0.0**	**19**
(9)	2005	0	(125)	125	133	17	0.0	0.0	**17**
(10)	2006	0	(111)	111	118	15	0.0	0.0	**15**
(11)	2007	0	(96)	96	104	13	0.0	0.0	**13**
(12)	2008	0	(82)	82	89	11	0.0	0.0	**11**
(13)	2009	0	(69)	69	75	9	0.0	0.0	**9**

Column Notes:
(2) See Schedule 1, Page 13, Column (4).
(3) See Schedule 1, Page 13, Column (9).
(4) Column (2) - Column (3).
(5) (Column (4) Prior Year + Column (4))/2.
(6) Column (5) x Total Pre-Valuation Rate of Return of 11.01% x Schedule 1, Page 1, Column (3).
(7) Average of (Unamortized Balance of Rate Clauses - Deferred Taxes on Rate Clauses) x 11.18% x Page 1, Column (3).
(8) Average of Unamortized Balance of ITC x 11.18% x Page 1, Column (3).
(9) Column (6) + Column (7) + Column (8).

Note: Savings from refinancing calculated as difference between 12.56% and 12.16% are included in the Reconciliation Account.

* Actual September 30, 1998 capital structure with pro-forma adjustments for known preferred stock redemptions which occurred in October and November.

Return Component	*BASE* Post-Divestiture Year End 1995	*REFINANCED* Post-Divestiture September * 1998
Capital Structure:		
LTD	44.07%	42.44%
Preferred	3.56%	0.21%
Common Equity	52.37%	57.35%
	100.00%	100.00%
Cost Rates:		
LTD	6.23%	4.15%
Preferred	5.69%	6.00%
Common Equity	11.00%	11.00%
Total Weighted Cost Rate	**8.71%**	**8.08%**
Reimbursement for Taxes on Equity Component	**3.85%**	**4.08%**
Total Rate of Return	**12.56%**	**12.16%**

Summary of Contract Termination Charges
New England Power Company (100%)

Variable Component

$ in Millions

Line	Year End (1)	Nuclear Decommissioning and Other Post-Shutdown Costs (2)	Power Contracts: Total Obligation (3)	Power Contracts: Assumed Market Value (4)	Power Contracts: Excess Over Market (5)	Future Power Contract Buyouts (6)	Credit for Unit Sales Contracts: Total Revenue (7)	Credit for Unit Sales Contracts: Assumed Market Value (8)	Credit for Unit Sales Contracts: Excess Over Market (9)	Above Market Fuel Transportation Costs (10)	Transmission in Support of Remote Generating Units (11)	Payments in Lieu of Property Taxes (12)	Employee Severance and Retraining Costs (13)	Damages, Costs, or Net Recoveries from Claims (14)	PBR for Nuclear Units Remaining After Market Valuation (15)	**Base Total Variable Component (16)**
(1)	**1998**	**23.8**	**0.0**	**0.0**	**0.0**	**60.8**	**(2.4)**	**(1.9)**	**(0.5)**	**0.0**	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**	**84.6**
(2)	**1999**	**55.7**	**0.0**	**0.0**	**0.0**	**182.1**	**(7.6)**	**(5.4)**	**(2.2)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.0**
(3)	**2000**	**47.5**	**0.0**	**0.0**	**0.0**	**181.4**	**(7.4)**	**(5.4)**	**(2.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**228.4**
(4)	**2001**	**56.6**	**0.0**	**0.0**	**0.0**	**180.7**	**(1.7)**	**(0.7)**	**(1.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.8**
(5)	**2002**	**45.1**	**0.0**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**225.2**
(6)	January	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(7)	February	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(8)	March	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(9)	April	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(10)	May	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(11)	June	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(12)	July	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(13)	August	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(14)	September	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(15)	October	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(16)	November	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(17)	December	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(18)	**2003**	**28.2**	**0.0**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**195.1**
(19)	January	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(20)	February	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(21)	March	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(22)	April	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(23)	May	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(24)	June	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(25)	July	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(26)	August	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(27)	September	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(28)	October	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(29)	November	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(30)	December	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(31)	**2004**	**29.1**	**0.0**	**0.0**	**0.0**	**158.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**187.9**
(32)	2005	29	101	60	41	117	0	0	0	0	0	0	0	0	0	**187**
(33)	2006	35	124	72	51	97	0	0	0	0	0	0	0	(17)	0	**166**
(34)	2007	32	123	69	54	7	0	0	0	0	0	0	0	0	0	**93**
(35)	2008	28	121	55	66	6	0	0	0	0	0	0	0	0	0	**100**
(36)	2009	25	87	42	45	6	0	0	0	0	0	0	0	0	0	**75**
(37)	2010	24	77	39	39	0	0	0	0	0	0	0	0	0	0	**62**
(38)	2011	0	77	39	38	0	0	0	0	0	0	0	0	0	0	**38**
(39)	2012	0	74	36	37	0	0	0	0	0	0	0	0	0	0	**37**
(40)	2013	0	76	38	38	0	0	0	0	0	0	0	0	0	0	**38**
(41)	2014	0	77	40	37	0	0	0	0	0	0	0	0	0	0	**37**
(42)	2015	0	76	41	34	0	0	0	0	0	0	0	0	0	0	**34**
(43)	2016	0	49	24	25	0	0	0	0	0	0	0	0	0	0	**25**
(44)	2017	0	38	18	20	0	0	0	0	0	0	0	0	0	0	**20**
(45)	2018	0	6	1	5	0	0	0	0	0	0	0	0	0	0	**5**
(46)	2019	0	5	0	5	0	0	0	0	0	0	0	0	0	0	**5**
(47)	2020	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(All Sources based upon estimates of Variable Costs)
(2) (Schedule 1, Page 6, Column (4) + Schedule 1, Page 7, Column (7)) x Schedule 1, Page 1, Column (3).
(5) Column (3) - Column (4).
(6) Per NEP/USGen "IPP Contract Transfer Agreement".
(7) Schedule 1, Page 10, Column (5) x Schedule 1, Page 1, Column (3).
(9) Column (7) - Column (8).
(10) Schedule 1, Page 11, Column (7) x Schedule 1, Page 1, Column (3).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

Reconciliation Adjustment

The Narragansett Electric Company Share

Revenue Adjustments

Line	Year (1)	Estimated Kwh Delivered (2)	Actual Kwh Delivered (3)	Delta Kwh Delivered (4)	Termination Charge Billed (5)	Narragansett Revenue Excess/ (Shortfall) (6)	
(1)	**1998**	**1,626**	**1,669**	**42**	**1.50**	**1.8**	***NO ADJUSTMENTS TO SEPTEMBER***
(2)	**1999**	**5,013**	**5,175**	**162**	**1.58**	**1.9**	
(3)	**2000**	**5,165**	**5,271**	**106**	**1.15**	**1.2**	
(4)	**2001**	**5,183**	**5,387**	**204**	**0.80**	**2.5**	
(5)	**2002**	**5,232**	**5,557**	**325**	**0.67**	**2.5**	
(6)	January	441	509	69	pro-rated	0.4	
(7)	February	441	468	28	**0.68**	0.2	
(8)	March	441	365	(76)	**0.68**	(0.5)	
(9)	April	441	420	(21)	**0.68**	(0.1)	
(10)	May	441	412	(29)	**0.68**	(0.2)	
(11)	June	441	421	(20)	**0.68**	(0.1)	
(12)	July	441	509	69	**0.68**	0.5	
(13)	August	441	661	220	**0.68**	1.5	
(14)	September	441	511	70	**0.68**	0.5	
(15)	October	441	444	4	**0.68**	0.0	
(16)	November	441	439	(1)	**0.68**	(0.0)	
(17)	December	441	488	48	**0.68**	0.3	
(18)	**2003**	**5,288**	**5,648**	**360**	**0.68**	**2.4**	
(19)	January	446	531	85	pro-rated	0.7	
(20)	February	446	487	41	**0.63**	0.3	
(21)	March	446	457	10	**0.63**	0.1	
(22)	April	446	440	(6)	**0.63**	0.0	
(23)	May	446	413	(33)	**0.63**	(0.2)	
(24)	June	446	455	9	**0.63**	0.1	
(25)	July	446	506	60	**0.63**	0.4	
(26)	August	446	527	81	**0.63**	0.5	
(27)	September	446	544	97	**0.63**	0.6	
(28)	October	446	446	0	**0.63**	0.0	
(29)	November	446	446	0	**0.63**	0.0	
(30)	December	446	446	0	**0.63**	0.0	
(31)	**2004**	**5,356**	**5,356**	**344**	**0.63**	**2.3**	
(32)	2005	5,428	5,428	0	0.67	0	
(33)	2006	5,496	5,496	0	0.66	0	
(34)	2007	5,562	5,562	0	0.40	0	
(35)	2008	5,628	5,628	0	0.42	0	
(36)	2009	5,695	5,695	0	0.31	0	
(37)	2010	5,783	5,783	0	0.24	0	
(38)	2011	5,864	5,864	0	0.15	0	
(39)	2012	5,946	5,946	0	0.15	0	
(40)	2013	6,029	6,029	0	0.14	0	
(41)	2014	6,114	6,114	0	0.13	0	
(42)	2015	6,199	6,199	0	0.12	0	
(43)	2016	6,286	6,286	0	0.09	0	
(44)	2017	6,374	6,374	0	0.07	0	
(45)	2018	6,463	6,463	0	0.02	0	
(46)	2019	6,554	6,554	0	0.01	0	
(47)	2020	6,646	6,646	0	0.00	0	
(48)	2021	6,739	6,739	0	0.00	0	
(49)	2022	6,833	6,833	0	0.00	0	
(50)	2023	6,929	6,929	0	0.00	0	
(51)	2024	7,026	7,026	0	0.00	0	
(52)	2025	7,124	7,124	0	0.00	0	
(53)	2026	7,224	7,224	0	0.00	0	
(54)	2027	7,325	7,325	0	0.00	0	
(55)	2028	7,427	7,427	0	0.00	0	
(56)	2029	7,531	7,531	0	0.00	0	

Column Notes:
(2) See Schedule 1, Page 1, Column (2).
(3) Actual Kwh delivered.
(4) Column (3) - Column (2).
(5) See Schedule 1, Page 1, Column (10).
(6) Column (4) x Column (5)/100.

Reconciliation Adjustment

(continued from page 2a)

The Narragansett Electric Company Share

New England Power Company Variable Cost Adjustments

Line		Estimated Base Variable Component (7)	Actual Nuclear Decommissioning Costs (8)	Actual Power Contracts Obligations (9)	Actual Power Contracts Market Value (10)	Actual Power Contract Buyouts (11)	Actual Unit Sales Contracts Revenue (12)	Actual Unit Sales Contracts Market Value (13)	Actual Above Market Fuel Transportation Costs (14)	Actual Transmission in Support of Remote Generating Units (15)	Actual Payments in Lieu of Property Property Taxes (16)	Actual Employee Severance and Retraining Costs (17)	Actual Damages, Costs, or Net Recoveries from Claims (18)	Actual PBR for Nuclear Units Remaining After Market Valuation (19)	Actual Environmental Response Costs (20)	NEP Actual Total Variable Component (21)	Delta Variable Component (22)	Narragansett Share of Delta Variable Component (23)	**Narragansett Annual Reconciliation Adjustment Excess/ (Shortfall) (24)**
(1)	**1998**	**84.6**	**17.2**	**0.0**	**0.0**	**60.8**	**(1.8)**	**(1.6)**	**0.0**	**0.6**	**0.0**	**(17.8)**	**(1.4)**	**6.0**	**0.0**	**65.2**	**(19.4)**	**(4.3)**	**6.1**
(2)	**1999**	**237.0**	**43.8**	**0.0**	**0.0**	**182.1**	**0.0**	**0.0**	**0.0**	**1.2**	**0.0**	**1.4**	**(36.9)**	**17.3**	**0.0**	**208.8**	**(28.1)**	**(6.3)**	**8.2**
(3)	**2000**	**228.4**	**29.9**	**0.0**	**0.0**	**181.4**	**0.0**	**0.0**	**0.0**	**1.4**	**0.0**	**(0.7)**	**(20.8)**	**(17.5)**	**0.0**	**173.7**	**(54.7)**	**(12.3)**	**13.5**
(4)	**2001**	**237.8**	**27.5**	**0.0**	**0.0**	**180.7**	**0.0**	**0.0**	**0.0**	**0.3**	**0.0**	**0.0**	**(3.6)**	**6.2**	**0.8**	**212.0**	**(25.9)**	**(5.8)**	**8.3**
(5)	**2002**	**225.2**	**21.4**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(1.1)**	**(0.2)**	**0.6**	**1.9**	**202.7**	**(22.5)**	**(5.0)**	**7.5**
(6)	January	16.3	0.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.5)	0.2	14.9	(1.4)	(0.3)	0.7
(7)	February	16.3	2.2	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	17.0	0.8	0.2	0.0
(8)	March	16.3	1.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.4	0.1	0.0	(0.5)
(9)	April	16.3	1.5	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	16.1	(0.2)	(0.0)	(0.1)
(10)	May	16.3	1.6	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	15.7	(0.6)	(0.1)	(0.1)
(11)	June	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.6	0.4	0.1	(0.2)
(12)	July	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.5	0.2	0.1	0.4
(13)	August	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4	0.2	0.0	1.5
(14)	September	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	16.7	0.4	0.1	0.4
(15)	October	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.5	0.3	0.1	(0.0)
(16)	November	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	16.6	0.3	0.1	(0.1)
(17)	December	16.3	2.7	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	(0.1)	(0.0)	0.3
(18)	**2003**	**195.1**	**27.8**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(0.4)**	**1.2**	**195.6**	**0.5**	**0.1**	**2.3**
(19)	January	15.7	1.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	15.2	(0.4)	(0.1)	0.8
(20)	February	15.7	3.5	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	16.8	1.1	0.2	0.0
(21)	March	15.7	2.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.2	0.5	0.1	(0.1)
(22)	April	15.7	3.0	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	17.2	1.5	0.3	(0.4)
(23)	May	15.7	2.9	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.2	1.5	0.3	(0.5)
(24)	June	15.7	3.0	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.3	1.7	0.4	(0.3)
(25)	July	15.7	3.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	17.3	1.7	0.4	0.0
(26)	August	15.7	3.1	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.1	1.5	0.3	0.2
(27)	September	15.7	2.5	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.8	1.1	0.2	0.4
(28)	October	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(29)	November	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(30)	December	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(31)	**2004**	**187.9**	**34.4**	**0.0**	**0.0**	**164.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.7**	**199.2**	**11.3**	**2.5**	**(0.2)**
(32)	2005	187	46	101	60	117	0	0	0	0	0	0	0	0	0	204	17	4	(4)
(33)	2006	166	35	124	72	97	0	0	0	0	0	0	0	0	0	183	17	4	(4)
(34)	2007	93	32	123	69	7	0	0	0	0	0	0	0	0	0	93	0	0	0
(35)	2008	100	28	121	55	6	0	0	0	0	0	0	0	0	0	100	0	0	0
(36)	2009	75	25	87	42	6	0	0	0	0	0	0	0	0	0	75	0	0	0
(37)	2010	62	24	77	39	0	0	0	0	0	0	0	0	0	0	62	0	0	0
(38)	2011	38	0	77	39	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(39)	2012	37	0	74	36	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(40)	2013	38	0	76	38	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(41)	2014	37	0	77	40	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(42)	2015	34	0	76	41	0	0	0	0	0	0	0	0	0	0	34	0	0	0
(43)	2016	25	0	49	24	0	0	0	0	0	0	0	0	0	0	25	0	0	0
(44)	2017	20	0	38	18	0	0	0	0	0	0	0	0	0	0	20	0	0	0
(45)	2018	5	0	6	1	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(46)	2019	5	0	5	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(47)	2020	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						0													

Column Notes:
(7) See Schedule 1, Page 15, Column (16).
(8)-(20) Actual expenses incurred.
(21) Column (8) + Column (9) - Column (10) + Column (11) + Column (12) - Column (13) + Column (14) + Column (15) + Column (16) + Column (17) + Column (18) + Column (19) + Column (20).
(22) Column (21) - Column (7).
(23) Column (22) x 22.4%.
(24) Schedule 2, Page 2a, Column (6) - Schedule 2, Page 2b, Column (23).

Reconciliation Account

The Narragansett Electric Company

The Narragansett Electric Company Account

Line	Year (1)	Reconciliation Adjustment (2)	Divestiture Related Adjustments per Section 1.1.4 (3)	Annual Shortfall/ (Excess) (4)	Pre-Tax Return on Balance (5)	Collection of Prior Year Balance Including Interest (6)	End of Year Account Balance (7)	Lump Sum Payment/ Narr Deferred Tax Funding (8)	Revised End of Year Account Balance (9)
						As of August 31, 1998	**(3.3)**		
(1)	**1998**	**(6.1)**	**(11.3)**	**(17.5)**	**(0.77)**	**0.0**	**(21.5)**		
(2)	**1999**	**(8.2)**	**(2.7)**	**(10.9)**	**(2.29)**	**12.6**	**(22.1)**	**17.5**	**(4.6)**
(3)	**2000**	**(13.5)**	**(1.5)**	**(12.3)**	**(1.30)**	**1.5**	**(16.7)**	**5.0**	**(11.7)**
(4)	**2001**	**(8.3)**	**(3.8)**	**(12.1)**	**(1.44)**	**13.1**	**(12.2)**		
(5)	**2002**	**(7.5)**	**(2.1)**	**(9.6)**	**(1.04)**	**16.6**	**(6.2)**		
(6)	January	(0.7)	(0.5)	(1.2)	(0.06)	0.7	(6.8)		
(7)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.7	(6.6)		
(8)	March	0.5	(0.5)	(0.0)	(0.07)	0.7	(5.9)		
(9)	April	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.7)		
(10)	May	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.4)		
(11)	June	0.2	(0.5)	(0.3)	(0.05)	0.7	(5.0)		
(12)	July	(0.4)	(0.5)	(0.9)	(0.05)	0.7	(5.2)		
(13)	August	(1.5)	(0.5)	(1.9)	(0.05)	0.7	(6.4)		
(14)	September	(0.4)	(0.5)	(0.9)	(0.07)	0.7	(6.6)		
(15)	October	0.0	(0.5)	(0.4)	(0.07)	0.7	(6.4)		
(16)	November	0.1	(0.5)	(0.4)	(0.07)	0.7	(6.2)		
(17)	December	(0.3)	(0.7)	(1.0)	(0.06)	0.7	(6.5)		
(18)	**2003**	**(2.3)**	**(6.1)**	**(8.4)**	**(0.73)**	**8.8**	**(6.5)**		
(19)	January	(0.8)	(0.5)	(1.3)	(0.07)	0.8	(7.1)		
(20)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.8	(6.8)		
(21)	March	0.1	(0.5)	(0.5)	(0.07)	0.8	(6.6)		
(22)	April	0.4	(0.6)	(0.2)	(0.07)	0.8	(6.1)		
(23)	May	0.5	(0.4)	0.1	(0.06)	0.8	(5.2)		
(24)	June	0.3	(0.5)	(0.2)	(0.05)	0.8	(4.7)		
(25)	July	(0.0)	(0.5)	(0.5)	(0.05)	0.8	(4.4)		
(26)	August	(0.2)	(0.5)	(0.7)	(0.04)	0.8	(4.4)		
(27)	September	(0.4)	(0.5)	(0.9)	(0.04)	0.8	(4.5)		
(28)	October	0.1	(0.5)	(0.4)	(0.05)	0.8	(4.1)		
(29)	November	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.8)		
(30)	December	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.5)		
(31)	**2004**	**0.2**	**(6.1)**	**(5.9)**	**(0.65)**	**9.6**	**(3.5)**		
(32)	2005	4	(6)	-2	0	7	1		
(33)	2006	4	(4)	0	0	2	3		
(34)	2007	0	(0)	0	0	0	2		
(35)	2008	0	(0)	0	0	0	2		
(36)	2009	0	(0)	0	0	0	1		
(37)	2010	0	0	0	0	0	1		
(38)	2011	0	0	0	0	0	1		
(39)	2012	0	0	0	0	-1	0		
(40)	2013	0	0	0	0	0	0		
(41)	2014	0	0	0	0	0	0		
(42)	2015	0	0	0	0	0	0		
(43)	2016	0	0	0	0	0	0		
(44)	2017	0	0	0	0	0	0		
(45)	2018	0	0	0	0	0	0		
(46)	2019	0	0	0	0	0	0		
(47)	2020	0	0	0	0	0	0		
(48)	2021	0	0	0	0	0	0		
(49)	2022	0	0	0	0	0	0		
(50)	2023	0	0	0	0	0	0		
(51)	2024	0	0	0	0	0	0		
(52)	2025	0	0	0	0	0	0		
(53)	2026	0	0	0	0	0	0		
(54)	2027	0	0	0	0	0	0		
(55)	2028	0	0	0	0	0	0		
(56)	2029	0	0	0	0	0	0		

Column Notes:
(2) See Schedule 2, Page 2b, Column (24) x -1.
(3) See Schedule 2, Page 5.
(4) Sum Columns (2) and (3). September 2000 includes unbilled revenue of $2.7m.
(5) Column (7) prior period (on average for 1/2 year) x 12.16%.
(6) In 1999, collection per 1998 CTC Reconciliation Filing; In 2000, collection represents 1999 balance per 1998 CTC Reconciliation filing plus return calculated based on mid year convention as a result of the lump sum payment. In 2001, Column (9) prior year x -1 + Column (5) current year.
In 2002 - 2029, Column (7) prior year x -1 - Column (5) current year. 2004 reflects unbilled revenue adjustment of $2.8m, 2005 reflects unbilled revenue of $2.6 million.
(7) Prior year Column (7) + current year Sum Column (4) through (6).
(8) The $17.5 million represents lump sum payment made by New England Power Company to The Narragansett Electric Company in December 1999.
The $5 million payment is to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.

Schedule 2
Page 4

Reconciliation Adjustment

New England Power Company (100%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

Line	Year (1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Transaction Costs (16)	TOTAL (17)
(1)	**1998**	**(2.121)**	**(27.968)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.344)**	**0.000**	**0.000**	**(0.620)**	**0.000**	**0.000**	**0.282**	**(30.770)**
(2)	**1999**	**(5.957)**	**0.000**	**(2.000)**	**(1.040)**	**(2.202)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.595)**	**(0.547)**	**0.154**	**(12.188)**
(3)	**2000**	**(5.853)**	**0.000**	**0.245**	**0.000**	**0.007**	**0.000**	**0.000**	**0.000**	**(1.135)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.736)**
(4)	**2001**	**(5.804)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.415)**	**(1.300)**	**(9.607)**	**(0.038)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(17.165)**
(5)	**2002**	**(5.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.078**	**(0.599)**	**(3.090)**	**0.000**	**0.000**	**0.000**	**0.000**	**(9.411)**
(6)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	(0.110)	(1.530)	0.000	0.000	0.000	0.000	(2.121)
(7)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.088)	(1.551)	0.000	0.000	0.000	0.000	(2.121)
(8)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.376)	(1.551)	0.000	0.000	0.000	0.000	(2.410)
(9)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.186)	(1.550)	0.000	0.000	0.000	0.000	(2.218)
(10)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.107)	(1.551)	0.000	0.000	0.000	0.000	(2.141)
(11)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.127)	(1.551)	0.000	0.000	0.000	0.000	(2.161)
(12)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.139)	(1.551)	0.000	0.000	0.000	0.000	(2.173)
(13)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.117)	(1.551)	0.000	0.000	0.000	0.000	(2.151)
(14)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.154)	(1.551)	0.000	0.000	0.000	0.000	(2.188)
(15)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.099)	(1.551)	0.000	0.000	0.000	0.000	(2.133)
(16)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.189)	(1.551)	0.000	0.000	0.000	0.000	(2.223)
(17)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.841)	(1.761)	0.000	0.000	0.000	0.000	(3.085)
(18)	**2003**	**(5.796)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.002**	**(2.531)**	**(18.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.125)**
(19)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.184)	(1.551)	0.000	0.000	0.000	0.000	(2.218)
(20)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.172)	(1.551)	0.000	0.000	0.000	0.000	(2.206)
(21)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.406)	(1.551)	0.000	0.000	0.000	0.000	(2.440)
(22)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.192)	(1.939)	0.000	0.000	0.000	0.000	(2.614)
(23)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.165)	(1.322)	0.000	0.000	0.000	0.000	(1.970)
(24)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.191)	(1.551)	0.000	0.000	0.000	0.000	(2.225)
(25)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.216)	(1.551)	0.000	0.000	0.000	0.000	(2.249)
(26)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.176)	(1.551)	0.000	0.000	0.000	0.000	(2.210)
(27)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.193)	(1.551)	0.000	0.000	0.000	0.000	(2.227)
(28)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(29)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(30)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(31)	**2004**	**(5.792)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.636)**	**(18.771)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.199)**
(32)	2005	**(5.789)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(2.960)	(18.612)	0.000	0.000	0.000	0.000	(27.361)
(33)	2006	(0.016)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(1.727)	(15.510)	0.000	0.000	0.000	0.000	(17.253)
(34)	2007	(0.013)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.013)
(35)	2008	(0.010)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.010)
(36)	2009	(0.007)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.007)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes operating expense charges.
(17) Sum of columns (2) through (16).

Reconciliation Adjustment

Narragansett Electric Company (22.4%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

	(1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Other (16)	TOTAL (17)
(1)	**1998**	**(0.475)**	**(10.718)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.077)**	**0.000**	**0.000**	**(0.139)**	**0.000**	**0.000**	**0.063**	**(11.346)**
(2)	**1999**	**(1.335)**	**0.000**	**(0.448)**	**(0.233)**	**(0.493)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.133)**	**(0.123)**	**0.034**	**(2.731)**
(3)	**2000**	**(1.312)**	**0.000**	**0.055**	**0.000**	**0.002**	**0.000**	**0.000**	**0.000**	**(0.254)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(1.510)**
(4)	**2001**	**(1.301)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.093)**	**(0.291)**	**(2.153)**	**(0.009)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(3.847)**
(5)	**2002**	**(1.300)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.017**	**(0.134)**	**(0.693)**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.109)**
(6)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.025)	(0.343)	0.000	0.000	0.000	0.000	(0.475)
(7)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.020)	(0.347)	0.000	0.000	0.000	0.000	(0.475)
(8)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.084)	(0.348)	0.000	0.000	0.000	0.000	(0.540)
(9)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.347)	0.000	0.000	0.000	0.000	(0.497)
(10)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.024)	(0.348)	0.000	0.000	0.000	0.000	(0.480)
(11)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.028)	(0.348)	0.000	0.000	0.000	0.000	(0.484)
(12)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.031)	(0.348)	0.000	0.000	0.000	0.000	(0.487)
(13)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.026)	(0.348)	0.000	0.000	0.000	0.000	(0.482)
(14)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.034)	(0.348)	0.000	0.000	0.000	0.000	(0.490)
(15)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.022)	(0.348)	0.000	0.000	0.000	0.000	(0.478)
(16)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.348)	0.000	0.000	0.000	0.000	(0.498)
(17)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.188)	(0.395)	0.000	0.000	0.000	0.000	(0.691)
(18)	**2003**	**(1.299)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.567)**	**(4.213)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.079)**
(19)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.041)	(0.348)	0.000	0.000	0.000	0.000	(0.497)
(20)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.494)
(21)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.091)	(0.348)	0.000	0.000	0.000	0.000	(0.547)
(22)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.434)	0.000	0.000	0.000	0.000	(0.586)
(23)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.037)	(0.296)	0.000	0.000	0.000	0.000	(0.441)
(24)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(25)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.048)	(0.348)	0.000	0.000	0.000	0.000	(0.504)
(26)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.495)
(27)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(28)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(29)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(30)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(31)	**2004**	**(1.298)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.591)**	**(4.207)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.095)**
(32)	2005	**(1.297)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.663)	(4.171)	0.000	0.000	0.000	0.000	(6.132)
(33)	2006	(0.004)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.387)	(3.476)	0.000	0.000	0.000	0.000	(3.866)
(34)	2007	(0.003)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.003)
(35)	2008	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)
(36)	2009	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes Narragansett Electric's 22.4% share of operating expense charges.
(17) Sum of columns (2) through (16).

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Newport Electric Corporation CTC Calculation

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO NEWPORT ELECTRIC COMPANY

Schedule 1
Page 1 of 15

YEAR (1)	EST. NEC MWH SALES (2)	SHARE OF FIXED COMPONENT $ IN 000 (3)	SHARE OF FIXED COMPONENT CENTS/KWH (4)	SHARE OF VAR. COMPONENT $ IN 000 (5)	SHARE OF VAR. COMPONENT CENTS/KWH (6)	SHARE OF TOTAL TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARGE CENTS/KWH (8)
1998	530,586	6,196	1.17	9,721	1.83	15,918	3.00
PRE RVC '99	134,139	1,666	1.24	2,358	1.76	4,025	3.00
POST RVC '99	402,416	4,154	1.03	4,139	1.03	8,293	2.06
2000	544,130	7,963	1.46	3,107	0.57	11,070	2.03
2001	549,613	3,371	0.61	4,411	0.80	7,782	1.42
2002	555,606	3,018	0.54	5,059	0.91	8,077	1.45
2003	563,367	4,395	0.78	4,838	0.86	9,232	1.64
2004	571,358	4,436	0.78	3,106	0.54	7,542	1.32
2005	580,288	3,741	0.64	3,141	0.54	6,882	1.19
2006	589,480	-4	0.00	5,295	0.90	5,291	0.90
2007	596,369	2,670	0.45	3,623	0.61	6,293	1.06
2008	603,135	2,011	0.33	2,431	0.40	4,441	0.74
2009	609,079	2,907	0.48	2,382	0.39	5,289	0.87
2010	616,061	0	0.00	1,085	0.18	1,085	0.18
2011	622,439	0	0.00	376	0.06	376	0.06
2012	627,545	0	0.00	341	0.05	341	0.05
2013	636,621	0	0.00	306	0.05	306	0.05
2014	643,741	0	0.00	297	0.05	297	0.05
2015	649,276	0	0.00	288	0.04	288	0.04
2016	654,269	0	0.00	280	0.04	280	0.04
2017	661,599	0	0.00	235	0.04	235	0.04
2018	667,717	0	0.00	228	0.03	228	0.03
2019	673,767	0	0.00	221	0.03	221	0.03
2020	680,723	0	0.00	188	0.03	188	0.03
2021	687,311	0	0.00	0	0.00	0	0.00
2022	694,002	0	0.00	0	0.00	0	0.00
2023	700,796	0	0.00	0	0.00	0	0.00
2024	707,697	0	0.00	0	0.00	0	0.00
2025	714,705	0	0.00	0	0.00	0	0.00
2026	721,821	0	0.00	0	0.00	0	0.00
2027	757,912	0	0.00	0	0.00	0	0.00
2028	795,808	0	0.00	0	0.00	0	0.00
2029	835,598	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	3,670	2,381	145	**6,196**	0	6,196
PRE RVC '99	862	769	36	**1,666**	0	1,666
POST RVC '99	2,944	2,327	(26)	**5,245**	(1,091)	4,154
2000	3,355	6,071	(36)	**9,390**	(1,427)	7,963
2001	2,948	1,870	(35)	**4,783**	(1,412)	3,371
2002	2,804	1,659	(33)	**4,430**	(1,412)	3,018
2003	2,605	3,233	(32)	**5,807**	(1,412)	4,395
2004	2,329	3,549	(30)	**5,848**	(1,412)	4,436
2005	2,057	3,125	(29)	**5,154**	(1,412)	3,741
2006	881	554	(27)	**1,408**	(1,412)	-4
2007	721	3,387	(26)	**4,082**	(1,412)	2,670
2008	461	2,986	(24)	**3,423**	(1,412)	2,011
2009	170	4,172	(23)	**4,319**	(1,412)	2,907

<u>COLUMN NOTES:</u>
EACH COLUMN REPRESENTS 11.85% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
VARIABLE COMPONENT

		POWER CONTRACTS				CREDIT FOR UNIT SALES CONTRACTS											
YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	POWER TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	949	17,296	8,161	9,134	0	(575)	0	(575)	56	157	0	0	0	0	9,721	0	**9,721**
PRE RVC '99	219	4,328	2,108	2,220	0	(132)	0	(132)	13	38	0	0	0	0	2,358	0	**2,358**
POST RVC '99	843	4,395	0	4,395	0	(257)	0	(257)	(80)	43	0	0	0	0	4,944	(805) **(a)**	**4,139**
2000	1,001	5,984	0	5,984	0	(97)	0	(97)	(61)	23	0	0	0	0	6,851	(3,744) **(b)**	**3,107**
2001	866	6,404	0	6,404	0	0	0	0	(38)	23	0	0	0	0	7,254	(2,844)	**4,411**
2002	773	6,429	0	6,429	0	0	0	0	0	7	0	0	0	0	7,208	(2,149)	**5,059**
2003	708	4,749	0	4,749	0	0	0	0	0	0	0	0	0	0	5,457	(619)	**4,838**
2004	687	4,415	0	4,415	0	0	0	0	0	0	0	0	0	0	5,102	(1,996)	**3,106**
2005	670	4,834	0	4,834	0	0	0	0	0	0	0	0	0	0	5,504	(2,364)	**3,141**
2006	1,020	4,219	0	4,219	0	0	0	0	0	0	0	0	0	0	5,239	56	**5,295**
2007	936	2,687	0	2,687	0	0	0	0	0	0	0	0	0	0	3,623	0	**3,623**
2008	811	1,620	0	1,620	0	0	0	0	0	0	0	0	0	0	2,431	0	**2,431**
2009	723	1,659	0	1,659	0	0	0	0	0	0	0	0	0	0	2,382	0	**2,382**
2010	699	385	0	385	0	0	0	0	0	0	0	0	0	0	1,085	0	**1,085**
2011	0	376	0	376	0	0	0	0	0	0	0	0	0	0	376	0	**376**
2012	0	341	0	341	0	0	0	0	0	0	0	0	0	0	341	0	**341**
2013	0	306	0	306	0	0	0	0	0	0	0	0	0	0	306	0	**306**
2014	0	297	0	297	0	0	0	0	0	0	0	0	0	0	297	0	**297**
2015	0	288	0	288	0	0	0	0	0	0	0	0	0	0	288	0	**288**
2016	0	280	0	280	0	0	0	0	0	0	0	0	0	0	280	0	**280**
2017	0	235	0	235	0	0	0	0	0	0	0	0	0	0	235	0	**235**
2018	0	228	0	228	0	0	0	0	0	0	0	0	0	0	228	0	**228**
2019	0	221	0	221	0	0	0	0	0	0	0	0	0	0	221	0	**221**
2020	0	188	0	188	0	0	0	0	0	0	0	0	0	0	188	0	**188**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 11.85% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE	LOCATION	YEAR(S) PLACED IN SERVICE	ENERGY SOURCE	NET CAPABILITY MW	$ IN 000 1995	$ IN 000 1997	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND	UNRECOVERED BALANCE @ APRIL 1, 1999
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
FOSSIL FUEL UNITS								
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158	22,135
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917	32,859
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030	1,806	112	1,686
NEWPORT DIESELS	JAMESTOWN/	1961	DIESEL	8.8	1,803	1,499	152	1,399
	PORTSMOUTH, RI/	1978	DIESEL	8.3				
	YARMOUTH, ME	1978	OIL	4.1				
NUCLEAR UNITS								
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878	150,217
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749	128,279	4,735	119,726
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786 (a)	3,092	347	2,886
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439 (a)	6,105	667	5,698
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604		564
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860	6,449	(b)	6,019
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610		2,436
			TOTAL	542.6	401,659	370,316	15,966	345,624

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995 (1)	BALANCE AS OF DECEMBER 31, 1997 (2)	APPLICABLE AMORTIZATION FOR 1996 AND BEYOND (3)		BASIS FOR DEFERRAL (4)	UNRECOVERED BALANCE @ APRIL 1, 1999
FAS 109 - ASSET	39,916	37,466	1,225		FERC RATEMAKING POLICY	34,968
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)		FERC RATEMAKING POLICY	(1,258)
- ITC GROSS-UP	(8,119)	(7,369)	(375)			(6,878)
FAS 106 DEFERRAL	1,313	538	387	(a)	FERC RATEMAKING POLICY	502
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)		FAS 87	(387)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607		FERC RATEMAKING POLICY	9,954
UNAMORTIZED ITC	(12,523)	(11,367)	(578)		FERC RATEMAKING POLICY	(10,609)
DREDGING	424	173	125	(b)	FERC RATEMAKING POLICY	161
TOTAL REG. ASSETS	27,941	28,343	(202)			26,453

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)	534	
DISCOUNT RATE	7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
PRE RVC '99	167	133	300	7,187
POST RVC '99	(124)	(93)	(218)	(1,866) (a)
2000	(187)	(120)	(306)	(1,680)
2001	(187)	(107)	(294)	(1,493)
2002	(187)	(94)	(281)	(1,306)
2003	(187)	(82)	(269)	(1,120)
2004	(187)	(69)	(256)	(933)
2005	(187)	(57)	(243)	(747)
2006	(187)	(44)	(231)	(560)
2007	(187)	(31)	(218)	(373)
2008	(187)	(19)	(206)	(187)
2009	(187)	(6)	(193)	0

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UP
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,731)	(6,161)	(2,480)	(140)	(1,976)	(17,487)
POST RVC '99	(352)	(322)	0	0	0	(674)
2000	0	(511)	0	0	0	(511)
2001	0	(319)	0	0	0	(319)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	**0**	**1,195**	**68**	**3,944**
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,522
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	**10,660**	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,970	20,094	1,226	**52,290**	0	52,290
PRE RVC '99	7,275	6,487	300	**14,063**	0	14,063
POST RVC '99	24,846	19,637	(218)	**44,266**	(9,209)	35,057
2000	28,310	51,236	(306)	**79,239**	(12,039)	67,200
2001	24,877	15,781	(294)	**40,364**	(11,916)	28,448
2002	23,665	14,003	(281)	**37,387**	(11,916)	25,471
2003	21,983	27,285	(269)	**49,000**	(11,916)	37,084
2004	19,653	29,954	(256)	**49,350**	(11,916)	37,435
2005	**17,359**	**26,374**	(243)	**43,489**	(11,916)	31,574
2006	7,437	4,674	(231)	**11,880**	(11,916)	-36
2007	6,083	28,586	(218)	**34,451**	(11,916)	22,535
2008	3,893	25,195	(206)	**28,883**	(11,916)	16,967
2009	1,434	35,208	(193)	**36,449**	(11,916)	24,533

COLUMN NOTES:
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.1185 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17) /.1185
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENTS
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END	BALANCE NET BOOK VALUE OF GENERATION	BALANCE GENERATION RELATED REG. ASSETS	TOTAL NET BOOK BASIS	BALANCE NET TAX VALUE OF GENERATION	BALANCE GENERATION RELATED REG. ASSETS	TOTAL TAX BASIS	EXCESS BOOK OVER TAX	DEFERRED TAXES
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	351,651	26,914	378,565	64,768	0	64,768	313,797	123,087
PRE RVC '99	345,624	26,453	372,077	63,658	0	63,658	308,419	120,977
POST RVC '99	322,555 (a)	42,062 (a)	364,617 (a)	57,468	0	57,468	307,149	120,479
2000	277,229	36,151	313,381	49,392	0	49,392	263,988	103,549
2001	263,269	34,331	297,600	46,905	0	46,905	250,695	98,335
2002	250,881	32,715	283,596	44,698	0	44,698	238,898	93,708
2003	226,743	29,568	256,311	40,398	0	40,398	215,914	84,692
2004	200,245	26,112	226,358	35,676	0	35,676	190,681	74,795
2005	82,858	10,805	93,663	14,762	0	14,762	78,900	30,949
2006	78,723	10,266	88,989	14,026	0	14,026	74,963	29,404
2007	53,435	6,968	60,403	9,520	0	9,520	50,883	19,959
2008	31,146	4,062	35,208	5,549	0	5,549	29,659	11,634
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	378,565	123,087	255,478	262,258	29,735	1,235	30,970
PRE RVC '99	372,077	120,977	251,100	246,722 (a)	6,993	282	7,275
POST RVC '99	364,617	120,479	244,137	253,044 (b)	24,846	0	24,846
2000	313,381	103,549	209,831	226,984	28,310	0	28,310
2001	297,600	98,335	199,265	204,548	24,877	0	24,877
2002	283,596	93,708	189,889	194,577	23,665	0	23,665
2003	256,311	84,692	171,619	180,754	21,983	0	21,983
2004	226,358	74,795	151,563	161,591	19,653	0	19,653
2005	93,663	30,949	62,714	107,138	**17,359**	0	17,359
2006	88,989	29,404	59,585	61,149	7,437	0	7,437
2007	60,403	19,959	40,444	50,014	6,083	0	6,083
2008	35,208	11,634	23,574	32,009	3,893	0	3,893
2009	0	0	0	11,787	1,434	0	1,434

EECo 12/31/95 **CAPITAL STRUCTURE**			PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000		ATWACC	BTWACC
COM PRE RVC	48.45%	9.20% (c)	4.46%	7.33%			57.35%	11.00% (c)	6.31%	10.38%
COM POST RVC		11.40%			5.52%	9.09%				
PFD	5.95%	9.83%	0.58%	0.96%	0.58%	0.96%	0.21%	6.00%	0.01%	0.02%
LTD	45.60%	6.67%	3.04%	3.04%	3.04%	3.04%	42.44%	4.15%	1.76%	1.76%
	100.00%		8.08%	11.338%	9.15%	13.092%	100.00%		8.08%	12.162%
TAX RATE				39.225%		39.225%				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND ASSOCIATED DEF TAXES OF ($17,792) AND $6,979 FOR ITC LIAB AND, $5,797 AND $1,456 FOR MAINE YANKEE
(c) PER NEP RI FILING.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

		POWER CONTRACTS				CREDIT FOR UNIT SALES CONTRACTS									
YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	TOTAL OBLIGATION (3)	ASSUMED MARKET VALUE (4)	NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	TOTAL OBLIGATION (7)	ASSUMED MARKET VALUE (8)	NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,522	17,790	18,732	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,902**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(674)	364	0	0	0	0	**41,719**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(511)	193	0	0	0	0	**57,814**
2001	7,304	54,041	0	54,041	0	0	0	0	(319)	193	0	0	0	0	**61,219**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	NEWPORT REVENUE EXCESS/ (SHORTFALL) (6)
2000	544,130	585,428	41,298	2.03	818
2001	549,613	593,463	(43,850)	1.42	645
2002	555,606	592,935	(37,329)	1.45	512
Jan-2003	46,947	58,604	(11,656)	1.64	132
Feb-2003	46,947	54,669	(7,722)	1.64	127
Mar-2003	46,947	52,512	(5,565)	1.64	92
Apr-2003	46,947	47,852	(905)	1.64	15
May-2003	46,947	43,838	3,109	1.64	(50)
Jun-2003	46,947	46,167	780	1.64	(12)
Jul-2003	46,947	52,304	(5,356)	1.64	88
Aug-2003	46,947	58,983	(12,035)	1.64	198
Sep-2003	46,947	58,037	(11,089)	1.64	182
Oct-2003	46,947	50,419	(3,472)	1.64	58
Nov-2003	46,947	45,451	1,497	1.64	(24)
Dec-2003	46,947	53,263	(6,315)	1.64	104
2003	563,367	622,097	(58,730)	1.64	910
Jan-2004	47,613	58,036	(10,423)	1.32	237
Feb-2004	47,613	55,559	(7,946)	1.32	104
Mar-2004	47,613	52,786	(5,172)	1.32	67
Apr-2004	47,613	49,067	(1,454)	1.32	18
May-2004	47,613	44,477	3,137	1.32	(42)
Jun-2004	47,613	46,527	1,087	1.32	(15)
Jul-2004	47,613	53,639	(6,026)	1.32	79
Aug-2004	47,613	56,318	(8,705)	1.32	114
Sep-2004	47,613	58,037	(10,424)	1.32	137
Oct-2004	47,613	**47,613**	0	1.32	(0)
Nov-2004	47,613	**47,613**	0	1.32	(0)
Dec-2004	47,613	**47,613**	0	1.32	(0)
2004	571,358	617,285	(45,927)	1.32	698
Jan-2005	48,357	48,357	0	1.19	0
Feb-2005	48,357	48,357	0	1.19	0
Mar-2005	48,357	48,357	0	1.19	0
Apr-2005	48,357	48,357	0	1.19	0
May-2005	48,357	48,357	0	1.19	0
Jun-2005	48,357	48,357	0	1.19	0
Jul-2005	48,357	48,357	0	1.19	0
Aug-2005	48,357	48,357	0	1.19	0
Sep-2005	48,357	48,357	0	1.19	0
Oct-2005	48,357	48,357	0	1.19	0
Nov-2005	48,357	48,357	0	1.19	0
Dec-2005	48,357	48,357	0	1.19	0
2005	580,288	580,288	0	1.19	0
2006	589,480	589,480	0	0.90	0
2007	596,369	596,369	0	1.06	0
2008	603,135	603,135	0	0.74	0
2009	609,079	609,079	0	0.87	0
2010	616,061	616,061	0	0.18	0
2011	622,439	622,439	0	0.06	0
2012	627,545	627,545	0	0.05	0
2013	636,621	636,621	0	0.05	0
2014	643,741	643,741	0	0.05	0
2015	649,276	649,276	0	0.04	0
2016	654,269	654,269	0	0.04	0
2017	661,599	661,599	0	0.04	0
2018	667,717	667,717	0	0.03	0
2019	673,767	673,767	0	0.03	0
2020	680,723	680,723	0	0.03	0
2021	687,311	687,311	0	0.00	0
2022	694,002	694,002	0	0.00	0
2023	700,796	700,796	0	0.00	0
2024	707,697	707,697	0	0.00	0
2025	714,705	714,705	0	0.00	0
2026	721,821	721,821	0	0.00	0
2027	757,912	757,912	0	0.00	0
2028	795,808	795,808	0	0.00	0
2029	835,598	835,598	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S DELIVERED THROUGH SEP 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFT
(4) COLUMN (3)- COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,814	5,971	0	0	43,286	(39)	(29)	(583)	142	0	0	(177)	(3,388)	45,240
2001	61,219	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,508)	(64)	48,385
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,409)	(55)	59,122
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,499
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(0)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,677
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(6)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,057
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,996) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,068)	0	36,341
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(10)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(3)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(5)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,295
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(118)	0	39,936
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) Represents Montaup's share of Millstone 3 employee severance costs.
(b) Includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) Includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL THROUGH SEP 2004, RE-ESTIMATED OCT - DEC 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL THROUGH SEP 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK.
AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT
NEWPORT ELECTRIC COMPANY
($000)

Schedule 2
Page 1c

YEAR (1)	DELTA VARIABLE COMP. (21)	NEWPORT SHARE DELTA VAR. COMP. (22)	NEWPORT ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,574)	(1,490)	2,308
2001	(12,834)	(1,521)	2,166
2002	(1,709)	(202)	714
Jan-2003	(2,061)	(244)	376
Feb-2003	(818)	(97)	224
Mar-2003	(635)	(75)	167
Apr-2003	661	78	(63)
May-2003	422	50	(100)
Jun-2003	(1,160)	(138)	125
Jul-2003	321	38	50
Aug-2003	304	36	162
Sep-2003	(171)	(20)	203
Oct-2003	219	26	32
Nov-2003	(63)	(7)	(16)
Dec-2003	(6,724)	(797)	901
2003	(9,706)	(1,150)	2,060
Jan-2004	(1,617)	(192)	429
Feb-2004	(93)	(11)	115
Mar-2004	147	17	50
Apr-2004	(530)	(63)	81
May-2004	(100)	(12)	(31)
Jun-2004	(279)	(33)	18
Jul-2004	(274)	(32)	111
Aug-2004	(293)	(35)	149
Sep-2004	(231)	(27)	164
Oct-2004	51	6	(6)
Nov-2004	51	6	(6)
Dec-2004	51	6	(6)
2004	(3,117)	(369)	1,067
Jan-2005	369	44	(44)
Feb-2005	369	44	(44)
Mar-2005	369	44	(44)
Apr-2005	369	44	(44)
May-2005	369	44	(44)
Jun-2005	369	44	(44)
Jul-2005	369	44	(44)
Aug-2005	369	44	(44)
Sep-2005	369	44	(44)
Oct-2005	369	44	(44)
Nov-2005	369	44	(44)
Dec-2005	(4,066)	(482)	482
2005	(11)	(1)	1
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 11.85%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			NEWPORT ELECTRIC COMPANY ACCOUNT							
YEAR (1)	DEFERRAL OF CONTRACT TERMINATION DATE (2)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (3)	BUYOUT SAVINGS (4)	VARIABLE RECONCIL. ADJUSTMENT (5)	DEFERRAL OF CONTRACT TERM. DATE (6)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (7)	BUYOUT SAVINGS (8)	ANNUAL SHORTFALL/ (EXCESS) (9)	ANNUAL PRE-TAX RETURN ON BALANCE (10)	COLLECTION OF PRIOR YR BAL. INCL. INTEREST (11)	END OF YR. ACCOUNT BALANCE (12)
1999	0	0	0	0	0	0	0	0	0	0	(3,744)
2000	0	0	0	(2,308)	0	0	0	(2,308)	(413)	(3,744)	(2,720)
2001	0	0	0	(2,166)	0	0	0	(2,166)	(348)	(2,844)	(2,391)
2002	0	0	0	(714)	0	0	0	(714)	(192)	(2,149)	(1,148)
Jan-2003	0	0	0	(376)	0	0	0	(376)	(13)	(52)	(1,485)
Feb-2003	0	0	0	(224)	0	0	0	(224)	(16)	(52)	(1,674)
Mar-2003	0	0	0	(167)	0	0	0	(167)	(18)	(52)	(1,807)
Apr-2003	0	0	0	63	0	0	0	63	(18)	(52)	(1,710)
May-2003	0	0	0	100	0	0	0	100	(17)	(52)	(1,575)
Jun-2003	0	0	0	(125)	0	0	0	(125)	(16)	(52)	(1,665)
Jul-2003	0	0	0	(50)	0	0	0	(50)	(17)	(52)	(1,680)
Aug-2003	0	0	0	(162)	0	0	0	(162)	(18)	(52)	(1,808)
Sep-2003	0	0	0	(203)	0	0	0	(203)	(19)	(52)	(1,979)
Oct-2003	0	0	0	(32)	0	0	0	(32)	(20)	(52)	(1,978)
Nov-2003	0	0	0	16	0	0	0	16	(20)	(52)	(1,930)
Dec-2003	0	0	0	(901)	0	0	0	(901)	(24)	(52)	(2,803)
2003	0	0	0	(2,060)	0	0	0	(2,060)	(214)	(619)	(2,803)
Jan-2004	0	0	0	(429)	0	0	0	(429)	(30)	(166)	(3,096)
Feb-2004	0	0	0	(115)	0	0	0	(115)	(31)	(166)	(3,075)
Mar-2004	0	0	0	(50)	0	0	0	(50)	(31)	(166)	(2,989)
Apr-2004	0	0	0	(81)	0	0	0	(81)	(30)	(166)	(2,934)
May-2004	0	0	0	31	0	0	0	31	(29)	(166)	(2,766)
Jun-2004	0	0	0	(18)	0	0	0	(18)	(27)	(166)	(2,644)
Jul-2004	0	0	0	(111)	0	0	0	(111)	(27)	(166)	(2,616)
Aug-2004	0	0	0	(149)	0	0	0	(149)	(26)	(166)	(2,624)
Sep-2004	0	0	0	(164)	0	0	0	(164)	(27)	(166)	(2,649)
Oct-2004	0	0	0	6	0	0	0	6	(26)	(166)	(2,502)
Nov-2004	0	0	0	6	0	0	0	6	(24)	(166)	(2,354)
Dec-2004	0	0	0	6	0	0	0	6	(23)	(166)	(2,205)
2004	0	0	0	(1,067)	0	0	0	(1,067)	(330)	(1,996)	(2,205)
Jan-2005	0	0	0	44	0	0	0	44	(21)	(197)	(1,985)
Feb-2005	0	0	0	44	0	0	0	44	(19)	(197)	(1,764)
Mar-2005	0	0	0	44	0	0	0	44	(17)	(197)	(1,540)
Apr-2005	0	0	0	44	0	0	0	44	(14)	(197)	(1,313)
May-2005	0	0	0	44	0	0	0	44	(12)	(197)	(1,085)
Jun-2005	0	0	0	44	0	0	0	44	(10)	(197)	(854)
Jul-2005	0	0	0	44	0	0	0	44	(7)	(197)	(621)
Aug-2005	0	0	0	44	0	0	0	44	(5)	(197)	(385)
Sep-2005	0	0	0	44	0	0	0	44	(3)	(197)	(147)
Oct-2005	0	0	0	44	0	0	0	44	(0)	(197)	93
Nov-2005	0	0	0	44	0	0	0	44	2	(197)	336
Dec-2005	0	0	0	(482)	0	0	0	(482)	2	(197)	53
2005	0	0	0	(1)	0	0	0	(1)	(104)	(2,364)	53
2006	0	0	0	0	0	0	0	0	3	56	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	(0)
2010	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	(0)
2014	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	(0)
2018	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	(0)
2022	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
										0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(4) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(6) COLUMN (2) x 11.85%
(7) COLUMN (3) x 11.85%
(8) COLUMN (4) x 11.85%
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 X RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Blackstone Valley Electric Company CTC Calculation

Print

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO BLACKSTONE VALLEY ELECTRIC

Schedule 1
Page 1 of 15

YEAR	EST. BVE MWH SALES	SHARE OF FIXED COMPONENT $ IN 000	SHARE OF FIXED COMPONENT CENTS/KWH	SHARE OF VAR. COMPONENT $ IN 000	SHARE OF VAR. COMPONENT CENTS/KWH	SHARE OF TOTAL TERM CHARGE $ IN 000	BASE CONTRACT TERM CHARGE CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
PRE RVC '99	327,284	4,021	1.23	5,797	1.77	9,819	3.00
POST RVC '99	981,853	9,866	1.00	10,198	1.04	20,064	2.04
2000	1,329,905	17,717	1.33	9,065	0.68	26,782	2.01
2001	1,346,024	8,079	0.60	12,689	0.94	20,767	1.54
2002	1,360,074	7,340	0.54	13,936	1.02	21,276	1.56
2003	1,377,851	10,865	0.79	13,392	0.97	24,257	1.76
2004	1,399,848	11,204	0.80	10,218	0.73	21,422	1.53
2005	1,423,866	9,647	0.68	10,272	0.72	19,919	1.40
2006	1,452,574	395	0.03	13,020	0.90	13,415	0.92
2007	1,471,219	8,550	0.58	8,906	0.61	17,456	1.19
2008	1,493,432	5,586	0.37	5,976	0.40	11,562	0.77
2009	1,512,696	7,986	0.53	5,856	0.39	13,842	0.92
2010	1,534,838	0	0.00	2,666	0.17	2,666	0.17
2011	1,550,396	0	0.00	923	0.06	923	0.06
2012	1,566,958	0	0.00	837	0.05	837	0.05
2013	1,597,666	0	0.00	752	0.05	752	0.05
2014	1,624,096	0	0.00	730	0.04	730	0.04
2015	1,644,785	0	0.00	708	0.04	708	0.04
2016	1,671,116	0	0.00	687	0.04	687	0.04
2017	1,693,977	0	0.00	579	0.03	579	0.03
2018	1,713,946	0	0.00	561	0.03	561	0.03
2019	1,739,097	0	0.00	544	0.03	544	0.03
2020	1,762,428	0	0.00	461	0.03	461	0.03
2021	1,787,024	0	0.00	0	0.00	0	0.00
2022	1,811,988	0	0.00	0	0.00	0	0.00
2023	1,837,328	0	0.00	0	0.00	0	0.00
2024	1,863,048	0	0.00	0	0.00	0	0.00
2025	1,889,155	0	0.00	0	0.00	0	0.00
2026	1,915,656	0	0.00	0	0.00	0	0.00
2027	2,011,439	0	0.00	0	0.00	0	0.00
2028	2,112,011	0	0.00	0	0.00	0	0.00
2029	2,217,611	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	9,035	5,507	357	**14,900**	0	14,900
PRE RVC '99	2,129	1,806	86	**4,021**	0	4,021
POST RVC '99	7,276	5,366	(63)	**12,578**	(2,712)	9,866
2000	8,395	12,957	(89)	**21,263**	(3,546)	17,717
2001	7,489	4,186	(86)	**11,589**	(3,510)	8,079
2002	7,165	3,767	(82)	**10,850**	(3,510)	7,340
2003	6,696	7,758	(78)	**14,375**	(3,510)	10,865
2004	6,023	8,766	(75)	**14,714**	(3,510)	11,204
2005	5,345	7,883	(71)	**13,157**	(3,510)	9,647
2006	2,439	1,533	(67)	**3,905**	(3,510)	395
2007	1,963	10,160	(64)	**12,060**	(3,510)	8,550
2008	1,227	7,930	(60)	**9,097**	(3,510)	5,586
2009	452	11,100	(56)	**11,496**	(3,510)	7,986

COLUMN NOTES:
EACH COLUMN REPRESENTS 29.13% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS: TOTAL OBLIGATION (3)	POWER CONTRACTS: ASSUMED MARKET VALUE (4)	POWER CONTRACTS: NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS: POWER TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS: ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS: NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	2,334	42,517	20,062	22,454	0	(1,414)	0	(1,414)	138	385	0	0	0	0	23,897	0	**23,897**
PRE RVC '99	538	10,639	5,182	5,456	0	(324)	0	(324)	33	94	0	0	0	0	5,797	0	**5,797**
POST RVC '99	2,073	10,803	0	10,803	0	(633)	0	(633)	(188)	106	0	0	0	0	12,161	(1,964) **(a)**	**10,198**
2000	2,460	14,711	0	14,711	0	(237)	0	(237)	(144)	56	0	0	0	0	16,846	(7,781) **(b)**	**9,065**
2001	2,128	15,742	0	15,742	0	0	0	0	(90)	56	0	0	0	0	17,836	(5,147)	**12,689**
2002	1,901	15,803	0	15,803	0	0	0	0	0	16	0	0	0	0	17,720	(3,784)	**13,936**
2003	1,739	11,674	0	11,674	0	0	0	0	0	0	0	0	0	0	13,413	(21)	**13,392**
2004	1,688	10,853	0	10,853	0	0	0	0	0	0	0	0	0	0	12,541	(2,324)	**10,218**
2005	1,648	11,883	0	11,883	0	0	0	0	0	0	0	0	0	0	13,530	(3,258)	**10,272**
2006	2,507	10,372	0	10,372	0	0	0	0	0	0	0	0	0	0	12,880	140	**13,020**
2007	2,300	6,606	0	6,606	0	0	0	0	0	0	0	0	0	0	8,906	0	**8,906**
2008	1,993	3,983	0	3,983	0	0	0	0	0	0	0	0	0	0	5,976	0	**5,976**
2009	1,778	4,078	0	4,078	0	0	0	0	0	0	0	0	0	0	5,856	0	**5,856**
2010	1,719	947	0	947	0	0	0	0	0	0	0	0	0	0	2,666	0	**2,666**
2011	0	923	0	923	0	0	0	0	0	0	0	0	0	0	923	0	**923**
2012	0	837	0	837	0	0	0	0	0	0	0	0	0	0	837	0	**837**
2013	0	752	0	752	0	0	0	0	0	0	0	0	0	0	752	0	**752**
2014	0	730	0	730	0	0	0	0	0	0	0	0	0	0	730	0	**730**
2015	0	708	0	708	0	0	0	0	0	0	0	0	0	0	708	0	**708**
2016	0	687	0	687	0	0	0	0	0	0	0	0	0	0	687	0	**687**
2017	0	579	0	579	0	0	0	0	0	0	0	0	0	0	579	0	**579**
2018	0	561	0	561	0	0	0	0	0	0	0	0	0	0	561	0	**561**
2019	0	544	0	544	0	0	0	0	0	0	0	0	0	0	544	0	**544**
2020	0	461	0	461	0	0	0	0	0	0	0	0	0	0	461	0	**461**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 29.13% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE	LOCATION	YEAR(S) PLACED IN SERVICE	ENERGY SOURCE	NET CAPABILITY MW	$ IN 000 1995	$ IN 000 1997	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND	UNRECOVERED BALANCE @ APRIL 1, 1999
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
FOSSIL FUEL UNITS								
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158	22,222
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917	32,990
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030	1,806	112	1,692
NEWPORT DIESELS	JAMESTOWN/	1961	DIESEL	8.8	1,803	1,499	152	1,405
	PORTSMOUTH, RI/	1978	DIESEL	8.3				
	YARMOUTH, ME	1978	OIL	4.1				
NUCLEAR UNITS								
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878	150,813
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749	128,279	4,735	120,200
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786 (a)	3,092	347	2,897
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439 (a)	6,105	667	5,721
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604		566
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860	6,449	(b)	6,043
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610		2,446
			TOTAL	542.6	401,659	370,316	15,966	346,994

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995 (1)	BALANCE AS OF DECEMBER 31, 1997 (2)	APPLICABLE AMORTIZATION FOR 1996 AND BEYOND (3)	BASIS FOR DEFERRAL (4)	UNRECOVERED BALANCE @ APRIL 1, 1999
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY	35,106
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)	FERC RATEMAKING POLICY	(1,263)
- ITC GROSS-UP	(8,119)	(7,369)	(375)		(6,905)
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY	504
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)	FAS 87	(389)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY	9,993
UNAMORTIZED ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY	(10,651)
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY	162
TOTAL REG. ASSETS	27,941	28,343	(202)		26,558

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)	534	
DISCOUNT RATE	7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)	
				8,023	
1998	669	557	1,226	7,354	
PRE RVC '99	167	133	300	7,187	
POST RVC '99	(124)	(93)	(218)	(1,866)	(a)
2000	(187)	(120)	(306)	(1,680)	
2001	(187)	(107)	(294)	(1,493)	
2002	(187)	(94)	(281)	(1,306)	
2003	(187)	(82)	(269)	(1,120)	
2004	(187)	(69)	(256)	(933)	
2005	(187)	(57)	(243)	(747)	
2006	(187)	(44)	(231)	(560)	
2007	(187)	(31)	(218)	(373)	
2008	(187)	(19)	(206)	(187)	
2009	(187)	(6)	(193)	0	

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UF
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,757)	(6,185)	(2,489)	(140)	(1,984)	(17,556)
						(4,614)
POST RVC '99	(336)	(308)	0	0	0	(644)
2000	0	(494)	0	0	0	(494)
2001	0	(309)	0	0	0	(309)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	0	**1,195**	**68**	3,944
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,521
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	10,660	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	31,016	18,907	1,226	**51,148**	0	51,148
PRE RVC '99	7,309	6,200	300	**13,810**	0	13,810
POST RVC '99	24,977	18,420	(218)	**43,179**	(9,309)	33,870
2000	28,821	44,481	(306)	**72,995**	(12,173)	60,822
2001	25,708	14,369	(294)	**39,783**	(12,050)	27,733
2002	24,596	12,932	(281)	**37,247**	(12,050)	25,197
2003	22,986	26,631	(269)	**49,349**	(12,050)	37,298
2004	20,676	30,093	(256)	**50,513**	(12,050)	38,463
2005	**18,349**	**27,062**	(243)	**45,168**	(12,050)	33,118
2006	8,374	5,263	(231)	**13,407**	(12,050)	1,357
2007	6,740	34,878	(218)	**41,400**	(12,050)	29,350
2008	4,211	27,221	(206)	**31,227**	(12,050)	19,177
2009	1,552	38,106	(193)	**39,464**	(12,050)	27,414

COLUMN NOTES:
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.2913 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17)/.2913.
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	352,754	26,999	379,752	64,971	0	64,971	314,781	123,473
PRE RVC '99	346,994	26,558	373,552	63,910	0	63,910	309,641	121,457
POST RVC '99	324,978 (a)	42,378 (a)	367,356 (a)	57,901	0	57,901	309,455	121,384
2000	285,629	37,247	322,876	50,890	0	50,890	271,985	106,686
2001	272,918	35,589	308,507	48,626	0	48,626	259,881	101,938
2002	261,478	34,097	295,575	46,587	0	46,587	248,988	97,666
2003	237,919	31,025	268,944	42,390	0	42,390	226,554	88,866
2004	211,298	27,554	238,851	37,647	0	37,647	201,205	78,922
2005	93,302	12,167	105,468	16,623	0	16,623	88,845	34,849
2006	88,646	11,560	100,205	15,794	0	15,794	84,411	33,110
2007	57,791	7,536	65,327	10,297	0	10,297	55,031	21,586
2008	33,710	4,396	38,106	6,006	0	6,006	32,100	12,591
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

Schedule 1
Page 14 of 15

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)		SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039					
1998	379,752	123,473	256,280	262,659		29,781	1,235	31,016
PRE RVC '99	373,552	121,457	252,095	247,911	(a)	7,027	282	7,309
POST RVC '99	367,356	121,384	245,973	254,372	(b)	24,977	0	24,977
2000	322,876	106,686	216,190	231,081		28,821	0	28,821
2001	308,507	101,938	206,569	211,379		25,708	0	25,708
2002	295,575	97,666	197,910	202,239		24,596	0	24,596
2003	268,944	88,866	180,078	188,994		22,986	0	22,986
2004	238,851	78,922	159,929	170,003		20,676	0	20,676
2005	105,468	34,849	70,619	115,274		**18,349**	0	18,349
2006	100,205	33,110	67,095	68,857		8,374	0	8,374
2007	65,327	21,586	43,741	55,418		6,740	0	6,740
2008	38,106	12,591	25,515	34,628		4,211	0	4,211
2009	0	0	0	12,757		1,552	0	1,552

EECo 12/31/95 **CAPITAL STRUCTURE**			PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000		ATWACC	BTWACC
COM PRE RVC	48.45%	9.20% (c)	4.46%	7.33%	5.52%	9.09%	57.35%	11.00% (c)	6.31%	10.38%
COM POST RVC		11.40%								
PFD PRE RVC	5.95%	9.83%	0.58%	0.96%	0.58%	0.96%	0.21%	6.00%	0.01%	0.02%
LTD PRE RVC	45.60%	6.67%	3.04%	3.04%	3.04%	3.04%	42.44%	4.15%	1.76%	1.76%
	100.00%		8.08%	11.338%	9.15%	13.092%	100.00%		8.08%	12.162%
TAX RATE				39.225%		39.225%				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND DEF TAXES OF ($17,847) AND $7,001 FOR ITC LIAB AND, $5,815 AND $1,461 FOR MAINE YANKEE
(c) PER NEP RI FILING.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS: TOTAL OBLIGATION (3)	POWER CONTRACTS: ASSUMED MARKET VALUE (4)	POWER CONTRACTS: NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS: TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS: ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS: NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,521	17,790	18,731	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,901**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(644)	364	0	0	0	0	**41,749**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(494)	193	0	0	0	0	**57,831**
2001	7,304	54,041	0	54,041	0	0	0	0	(309)	193	0	0	0	0	**61,229**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	BLACKSTONE VALLEY REVENUE EXCESS/ (SHORTFALL) (6)
2000	1,329,905	1,353,414	23,509	2.01	352
2001	1,346,024	1,350,390	(4,366)	1.54	29
2002	1,360,074	1,364,403	(4,328)	1.56	(4)
Jan-2003	114,821	126,572	(11,751)	1.76	71
Feb-2003	114,821	116,475	(1,654)	1.76	29
Mar-2003	114,821	110,251	4,570	1.76	(81)
Apr-2003	114,821	103,044	11,777	1.76	(208)
May-2003	114,821	104,483	10,338	1.76	(183)
Jun-2003	114,821	102,290	12,531	1.76	(221)
Jul-2003	114,821	124,693	(9,872)	1.76	173
Aug-2003	114,821	132,119	(17,298)	1.76	304
Sep-2003	114,821	123,055	(8,234)	1.76	144
Oct-2003	114,821	109,256	5,565	1.76	(99)
Nov-2003	114,821	109,428	5,393	1.76	(95)
Dec-2003	114,821	122,955	(8,135)	1.76	143
2003	1,377,851	1,384,622	(6,771)	1.76	(23)
Jan-2004	116,654	115,422	1,232	1.53	123
Feb-2004	116,654	117,641	(987)	1.53	15
Mar-2004	116,654	116,435	219	1.53	(4)
Apr-2004	116,654	102,351	14,303	1.53	(219)
May-2004	116,654	104,274	12,380	1.53	(190)
Jun-2004	116,654	118,093	(1,439)	1.53	22
Jul-2004	116,654	115,540	1,114	1.53	(17)
Aug-2004	116,654	119,279	(2,625)	1.53	40
Sep-2004	116,654	126,650	(9,996)	1.53	153
Oct-2004	116,654	**116,654**	0	1.53	(0)
Nov-2004	116,654	**116,654**	0	1.53	(0)
Dec-2004	116,654	**116,654**	0	1.53	(0)
2004	1,399,848	1,385,648	14,200	1.53	(79)
Jan-2005	118,656	118,656	0	1.40	0
Feb-2005	118,656	118,656	0	1.40	0
Mar-2005	118,656	118,656	0	1.40	0
Apr-2005	118,656	118,656	0	1.40	0
May-2005	118,656	118,656	0	1.40	0
Jun-2005	118,656	118,656	0	1.40	0
Jul-2005	118,656	118,656	0	1.40	0
Aug-2005	118,656	118,656	0	1.40	0
Sep-2005	118,656	118,656	0	1.40	0
Oct-2005	118,656	118,656	0	1.40	0
Nov-2005	118,656	118,656	0	1.40	0
Dec-2005	118,656	118,656	0	1.40	0
2005	1,423,866	1,423,866	0	1.40	0
2006	1,452,574	1,452,574	0	0.92	0
2007	1,471,219	1,471,219	0	1.19	0
2008	1,493,432	1,493,432	0	0.77	0
2009	1,512,696	1,512,696	0	0.92	0
2010	1,534,838	1,534,838	0	0.17	0
2011	1,550,396	1,550,396	0	0.06	0
2012	1,566,958	1,566,958	0	0.05	0
2013	1,597,666	1,597,666	0	0.05	0
2014	1,624,096	1,624,096	0	0.04	0
2015	1,644,785	1,644,785	0	0.04	0
2016	1,671,116	1,671,116	0	0.04	0
2017	1,693,977	1,693,977	0	0.03	0
2018	1,713,946	1,713,946	0	0.03	0
2019	1,739,097	1,739,097	0	0.03	0
2020	1,762,428	1,762,428	0	0.03	0
2021	1,787,024	1,787,024	0	0.00	0
2022	1,811,988	1,811,988	0	0.00	0
2023	1,837,328	1,837,328	0	0.00	0
2024	1,863,048	1,863,048	0	0.00	0
2025	1,889,155	1,889,155	0	0.00	0
2026	1,915,656	1,915,656	0	0.00	0
2027	2,011,439	2,011,439	0	0.00	0
2028	2,112,011	2,112,011	0	0.00	0
2029	2,217,611	2,217,611	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S THROUGH SEP. 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFTER.
(4) COLUMN (3) - COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

Schedule 2
Page 1b

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,831	5,971	0	0	43,286	(39)	(29)	(584)	142	0	0	(182)	(3,390)	45,233
2001	61,229	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,563)	(72)	48,322
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,416)	(61)	59,110
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,498
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(1)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,676
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(7)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,056
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,997) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,071)	0	36,338
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(11)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(4)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(6)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,294
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(121)	0	39,933
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) represents Montaup's share of Millstone 3 employee severance costs.
(b) includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004, RE-ESTIMATED OCT. - DEC. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 16, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK. AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT **Schedule 2**
BLACKSTONE VALLEY ELECTRIC **Page 1c**
($000)

YEAR (1)	DELTA VARIABLE COMP. (21)	BLACKSTONE VALLEY SHARE DELTA VAR. COMP. (22)	BLACKSTONE VALLEY ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,598)	(3,670)	4,021
2001	(12,907)	(3,760)	3,788
2002	(1,721)	(501)	497
Jan-2003	(2,061)	(600)	671
Feb-2003	(818)	(238)	267
Mar-2003	(636)	(185)	104
Apr-2003	661	193	(400)
May-2003	421	123	(305)
Jun-2003	(1,161)	(338)	117
Jul-2003	321	93	80
Aug-2003	303	88	215
Sep-2003	(171)	(50)	194
Oct-2003	219	64	(162)
Nov-2003	(63)	(18)	(77)
Dec-2003	(6,724)	(1,959)	2,101
2003	(9,709)	(2,828)	2,805
Jan-2004	(1,618)	(471)	594
Feb-2004	(93)	(27)	42
Mar-2004	146	43	(46)
Apr-2004	(530)	(154)	(65)
May-2004	(100)	(29)	(161)
Jun-2004	(279)	(81)	103
Jul-2004	(274)	(80)	62
Aug-2004	(293)	(85)	125
Sep-2004	(232)	(67)	220
Oct-2004	51	15	(15)
Nov-2004	51	15	(15)
Dec-2004	51	15	(15)
2004	(3,120)	(909)	830
Jan-2005	369	107	(107)
Feb-2005	369	107	(107)
Mar-2005	369	107	(107)
Apr-2005	369	107	(107)
May-2005	369	107	(107)
Jun-2005	369	107	(107)
Jul-2005	369	107	(107)
Aug-2005	369	107	(107)
Sep-2005	369	107	(107)
Oct-2005	369	107	(107)
Nov-2005	369	107	(107)
Dec-2005	(4,066)	(1,185)	1,185
2005	(11)	(3)	3
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 29.13%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY ELECTRIC SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			BLACKSTONE VALLEY ELECTRIC COMPANY ACCOUNT							
YEAR	DEFERRAL OF CONTRACT TERMINATION DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	VARIABLE RECONCIL. ADJUSTMENT	DEFERRAL OF CONTRACT TERM. DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	ANNUAL SHORTFALL/ (EXCESS)	ANNUAL PRE-TAX RETURN ON BALANCE	COLLECTION OF PRIOR YR BAL. INCL. INTEREST	END OF YR. ACCOUNT BALANCE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1999	0	0	0	0	0	0	0	0	0	0	(7,781)
2000	0	0	0	(4,021)	0	0	0	(4,021)	(789)	(7,781)	(4,810)
2001	0	0	0	(3,788)	0	0	0	(3,788)	(626)	(5,147)	(4,078)
2002	0	0	0	(497)	0	0	0	(497)	(251)	(3,784)	(1,041)
Jan-2003	0	0	0	(671)	0	0	0	(671)	(14)	(2)	(1,725)
Feb-2003	0	0	0	(267)	0	0	0	(267)	(19)	(2)	(2,009)
Mar-2003	0	0	0	(104)	0	0	0	(104)	(21)	(2)	(2,132)
Apr-2003	0	0	0	400	0	0	0	400	(20)	(2)	(1,749)
May-2003	0	0	0	305	0	0	0	305	(16)	(2)	(1,458)
Jun-2003	0	0	0	(117)	0	0	0	(117)	(15)	(2)	(1,589)
Jul-2003	0	0	0	(80)	0	0	0	(80)	(16)	(2)	(1,683)
Aug-2003	0	0	0	(215)	0	0	0	(215)	(18)	(2)	(1,915)
Sep-2003	0	0	0	(194)	0	0	0	(194)	(20)	(2)	(2,128)
Oct-2003	0	0	0	162	0	0	0	162	(21)	(2)	(1,985)
Nov-2003	0	0	0	77	0	0	0	77	(20)	(2)	(1,926)
Dec-2003	0	0	0	(2,101)	0	0	0	(2,101)	(30)	(2)	(4,055)
2003	0	0	0	(2,805)	0	0	0	(2,805)	(230)	(21)	(4,055)
Jan-2004	0	0	0	(594)	0	0	0	(594)	(43)	(194)	(4,499)
Feb-2004	0	0	0	(42)	0	0	0	(42)	(45)	(194)	(4,392)
Mar-2004	0	0	0	46	0	0	0	46	(43)	(194)	(4,196)
Apr-2004	0	0	0	65	0	0	0	65	(41)	(194)	(3,978)
May-2004	0	0	0	161	0	0	0	161	(39)	(194)	(3,663)
Jun-2004	0	0	0	(103)	0	0	0	(103)	(37)	(194)	(3,609)
Jul-2004	0	0	0	(62)	0	0	0	(62)	(36)	(194)	(3,513)
Aug-2004	0	0	0	(125)	0	0	0	(125)	(35)	(194)	(3,480)
Sep-2004	0	0	0	(220)	0	0	0	(220)	(35)	(194)	(3,542)
Oct-2004	0	0	0	15	0	0	0	15	(35)	(194)	(3,368)
Nov-2004	0	0	0	15	0	0	0	15	(33)	(194)	(3,192)
Dec-2004	0	0	0	15	0	0	0	15	(31)	(194)	(3,015)
2004	0	0	0	(830)	0	0	0	(830)	(453)	(2,324)	(3,015)
Jan-2005	0	0	0	107	0	0	0	107	(29)	(272)	(2,665)
Feb-2005	0	0	0	107	0	0	0	107	(25)	(272)	(2,311)
Mar-2005	0	0	0	107	0	0	0	107	(21)	(272)	(1,953)
Apr-2005	0	0	0	107	0	0	0	107	(18)	(272)	(1,592)
May-2005	0	0	0	107	0	0	0	107	(14)	(272)	(1,228)
Jun-2005	0	0	0	107	0	0	0	107	(11)	(272)	(859)
Jul-2005	0	0	0	107	0	0	0	107	(7)	(272)	(487)
Aug-2005	0	0	0	107	0	0	0	107	(3)	(272)	(111)
Sep-2005	0	0	0	107	0	0	0	107	1	(272)	269
Oct-2005	0	0	0	107	0	0	0	107	5	(272)	652
Nov-2005	0	0	0	107	0	0	0	107	9	(272)	1,039
Dec-2005	0	0	0	(1,185)	0	0	0	(1,185)	6	(272)	132
2005	0	0	0	(3)	0	0	0	(3)	(108)	(3,258)	132
2006	0	0	0	0	0	0	0	0	8	140	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2008	0	0	0	0	0	0	0	0	(0)	(0)	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2012	0	0	0	0	0	0	0	0	(0)	(0)	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2016	0	0	0	0	0	0	0	0	(0)	(0)	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2020	0	0	0	0	0	0	0	0	(0)	(0)	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2024	0	0	0	0	0	0	0	0	(0)	(0)	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 x RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

ATTACHMENT C
The 2005 CTC Settlement

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

New England Power Company) Docket No. ER-

AGREEMENT TO AMEND NEP/THE NARRAGANSETT ELECTRIC COMPANY T1 SERVICE AGREEMENT

WHEREAS, New England Power Company ("NEP"), The Narragansett Electric Company ("Narragansett"), the Rhode Island Public Utilities Commission ("Rhode Island Commission"), Rhode Island Division of Public Utilities and Carriers ("Rhode Island Division"), and Rhode Island Attorney General ("Rhode Island Attorney General")(together the "Parties") entered into a comprehensive restructuring agreement with several other signatories that was approved by this Commission in Docket Nos. ER97-680-000 and ER98-6-000 for NEP, and parallel restructuring agreements in Docket No. ER97-2800-000 between the former Montaup Electric Company ("Montaup"), which has merged into NEP, and the former Blackstone Valley Electric Company and Newport Electric Company, which have merged into Narragansett ("Restructuring Agreements").

WHEREAS, NEP and Narragansett entered into an amended service agreement under NEP's FERC Electric Tariff, Original Volume No.1 ("NEP/Narragansett T1 Service Agreement").

WHEREAS, under the Restructuring Agreements, NEP and Montaup are required to make annual reconciliations of the Contract Termination Charges ("CTC").

WHEREAS, these annual reconciliations are subject to dispute resolution before this Commission under Section 3.5 of the Restructuring Agreements.

WHEREAS, NEP and Narragansett have filed the following reports with the Rhode Island Public Utilities Commission: Reconciliation of CTC to Narragansett filed on December 1, 2000 ("2000 Reconciliation Report"), November 30, 2001 ("2001 Reconciliation Report"), November 26, 2002 ("2002 Reconciliation Report"), November 26, 2003 ("2003 Reconciliation Report"), and November 24, 2004 ("2004 Reconciliation Report") (together "Reconciliation Reports").

WHEREAS, the Parties have raised competing and disputed claims with regard to the issues in these Reconciliation Reports, but wish to resolve those matters on mutually agreeable terms, and without establishing any new precedent or principle applicable to any other proceedings.

WHEREAS, the Parties acknowledge and affirm the ongoing and reconciling nature of the charges related to the Reconciliation Reports and relevant Rhode Island Public Utilities Commission filings addressed by this Settlement.

NOW THEREFORE, in consideration of settling the specified outstanding issues relating to the Reconciliation Reports as set forth in Section 3, below, the Parties hereby agree as follows:

1. NEP shall provide a lump sum payment of $10 million to Narragansett. NEP shall also reflect as a credit to the CTC formula, for the period from January 1, 2005 through the end of the fixed recovery period or December 31, 2009 when this pollution

control financing credit will expire, Narragansett's 22.4 percent share of the actual transmission rate base supported by the pollution control debt actually billed by NEP through its monthly transmission bills times 3.72 percent, which represents the difference between the actual debt rate reflected in NEP's transmission bills of 7.87 percent and the settled pollution control debt rate of 4.15 percent. This prospective commitment is subject to the condition in NEP's Restructuring Agreement (Appendix 1, Section 1.1.4(e)) that to the extent that any of these financing savings are allocated to transmission rates by the Commission, they shall not also be allocated to the CTC.

2. The Parties agree that the provisions of Section 1 above finally resolve the following specified issues presented by the Reconciliation Reports, related to: (i) any transactions and agreements concerning NEP's and Montaup's former ownership interest in the Millstone III Nuclear Generation Station, and NEP's and Montaup's obligations related thereto including the level of proceeds from the settlement of NEP's and Montaup's litigation with Northeast Utilities and it's affiliates concerning the operation of the Station, and from the sale of NEP's and Montaup's entitlements in the Station; (ii) the return on the final fuel cores and materials and supplies at any nuclear units in which NEP or Montaup held an ownership interest or entitlement; (iii) the return on Montaup's payments to buy out of the purchased power contract for a portion of the output from the Pilgrim Nuclear Unit; and (iv) the credit that NEP reflected in the CTC associated with the pollution control debt in NEP's capital structure and will reflect in the CTC prospectively.

The Parties stipulate that no further adjustments to the Reconciliation Reports associated with these specified issues are warranted, and, except for a breach of this agreement, agree not to bring any action, claim or complaint associated with these specified issues set forth in the Reconciliation Reports, or to seek any adjustment to the reconciliations billed by NEP or Montaup associated with these specified issues before this Commission under Section 3.5 of the Restructuring Agreements, any other provision of the Commission's regulations, or the Federal Power Act.

The Parties have not together identified or discussed any additional unresolved issues related to the Reconciliation Reports and do not anticipate further proceedings involving any issues presented by those Reconciliation Reports and supply-related costs.

3. NEP and Narragansett shall amend the NEP/Narragansett T1 Service Agreement by adding the following Section 8 to the Contract Termination Charge Amendment of the NEP/Narragansett T1 Service Agreement:

> NEP shall provide a lump sum payment of $10 million to Narragansett to resolve the issues specified in the following paragraph that are associated with the 2000 Reconciliation Report, the 2001 Reconciliation Report, the 2002 Reconciliation Report, the 2003 Reconciliation Report, and the 2004 Reconciliation Report filed by NEP and Montaup Electric Company ("Montaup") (together "Reconciliation Reports"). In addition, NEP shall reflect as a credit to its annual CTC formula, for the period from January 1, 2005 through the end of the fixed recovery period or December 31, 2009 when this pollution control financing credit will expire, the Customer's 22.4 percent share of the actual transmission rate base supported by the pollution control debt actually billed by NEP through its monthly transmission bills times 3.72%, which represents the difference between the actual debt rate reflected in NEP's transmission bills of 7.87% and the settled pollution control debt rate of 4.15%. This prospective commitment is subject to the condition in the NEP's Restructuring Agreement (Appendix 1, Section 1.1.4(e)) that to the extent any of these financing savings are allocated to transmission rates by the Commission, they shall not also be allocated to the CTC.
>
> With the refund of the $10 million and the prospective credit implemented by NEP under the prior paragraph, the Customer accepts as final the resolution of the following specified issues presented by the Reconciliation Reports related to: (i) any transactions and agreements related to NEP's and Montaup's ownership interests in the Millstone III Nuclear Generation Station and NEP's and Montaup's obligations related thereto including the level of proceeds from the settlement of NEP's and Montaup's litigation with Northeast Utilities and its affiliates concerning the

operation of the Station, and from the sale of NEP's and Montaup's entitlements in the Station; (ii) the return on the final fuel cores and materials and supplies at any nuclear units in which NEP or Montaup held an ownership interest or entitlement; (iii) the return on Montaup's payments to buy out of the purchased power contract for a portion of the output from the Pilgrim Nuclear Unit; (iv) the credit that NEP reflects in the CTC associated with the pollution control debt in NEP's capital structure and will reflect in the CTC prospectively.

The Customer stipulates that no further adjustments associated with the issues specified in the prior paragraph are warranted, and agrees not to bring any action, claim, or complaint associated with these specified issues, or to seek any adjustment to the reconciliations billed by NEP or Montaup associated with these specified issues before the Federal Energy Regulatory Commission under Section 3.5 of NEP's and Montaup's Restructuring Agreements, any provision of the Commission's regulations, or the Federal Power Act.

4. The making of this Settlement shall not be deemed in any respect to constitute an admission by any party that any allegation or contention in this proceeding is true and valid.

5. Except as specifically set forth in this Settlement as necessary to accomplish the customer benefit intended by this Settlement, the Commission's approval of this Settlement shall not constitute approval of, or precedent regarding any principle or issue in this proceeding.

6. The discussions which have produced this Settlement have been conducted on the explicit understanding, pursuant to Rule 602(3) of the Commission's Rules of Practice and Procedure, that all offers of settlement and discussions relating thereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussions and are not to be used in any manner in connection with these or any other proceedings.

7. This Settlement is expressly conditioned upon the Commission's acceptance of all provisions hereof without change or condition, and in the event that the Commission

does not accept this Settlement in its entirety, this Settlement shall be deemed withdrawn and shall not constitute any part of the record in any proceeding or be used for any other purpose, and each of its provisions shall be deemed null and void.

Respectfully submitted,
THE NARRAGANSETT ELECTRIC COMPANY
AND NEW ENGLAND POWER COMPANY

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November 14, 2005

THE RHODE ISLAND PUBLIC UTILITIES COMMISSION

By: Its Attorney:

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November 14, 2005

THE DEPARTMENT OF THE ATTORNEY GENERAL

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

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NOVEMBER ~~October~~ 14, 2005

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Narragansett Electric Company CTC Calculation

New England Power Company
Summary of Contract Termination Charges
to The Narragansett Electric Company

POST-DIVESTITURE
2004 CTC Reconciliation

Line	Year (1)	Estimated Narragansett Electric Company Gwh Delivered (2)	Portion of the Year for Retail Access (3)	Estimated Narragansett Electric Company Gwh Delivered for Portion of the Year (4)	Share of Fixed Component $ in Millions (5)	Share of Fixed Component cents/kwh (6)	Share of Variable Component $ in Millions (7)	Share of Variable Component cents/kwh (8)	Share of Total Termination Charge $ in Millions (9)	***TOTAL CTC EXPENSES*** **Contract Termination Charge cents/kwh** (10)	Less Prepayment & Lump Sum Payment $ in Millions (11)	Adjusted CTC $ in Millions (12)	Adjusted CTC cents/kwh (13)
(1)	**1998**	**1,626**	**100%**	**1,626**	**5.4**	**0.33**	**19.0**	**1.17**	**24.4**	**1.50**			
(2)	**1999**	**5,013**	**100%**	**5,013**	**38.8**	**0.77**	**40.5**	**0.81**	**79.2**	**1.58**	**21.4**	**57.8**	**1.15**
(3)	**2000**	**5,165**	**100%**	**5,165**	**9.9**	**0.19**	**49.7**	**0.96**	**59.6**	**1.15**	**17.5**	**42.1**	**0.82**
(4)	**2001**	**5,183**	**100%**	**5,183**	**1.4**	**0.03**	**40.2**	**0.78**	**41.5**	**0.80**	**5.0**	**N/A**	**N/A**
(5)	**2002**	**5,232**	**100%**	**5,232**	**1.3**	**0.02**	**33.8**	**0.65**	**35.1**	**0.67**			
(6)	January	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(7)	February	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(8)	March	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(9)	April	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(10)	May	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(11)	June	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(12)	July	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(13)	August	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(14)	September	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(15)	October	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(16)	November	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(17)	December	441	100%	441	0.1	0.02	2.9	0.66	3.0	**0.68**			
(18)	**2003**	**5,288**	**100%**	**5,288**	**1.2**	**0.02**	**34.9**	**0.66**	**36.1**	**0.68**			
(19)	January	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(20)	February	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(21)	March	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(22)	April	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(23)	May	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(24)	June	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(25)	July	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(26)	August	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(27)	September	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(28)	October	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(29)	November	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(30)	December	446	100%	446	0.1	0.02	2.7	0.61	2.8	**0.63**			
(31)	**2004**	**5,356**	**100%**	**5,356**	**1.1**	**0.02**	**32.5**	**0.61**	**33.7**	**0.63**			
(32)	2005	5,428	100%	5,428	1	0.02	35	0.65	36	**0.67**			
(33)	2006	5,496	100%	5,496	1	0.02	35	0.64	36	**0.66**			
(34)	2007	5,562	100%	5,562	1	0.02	21	0.38	22	**0.40**			
(35)	2008	5,628	100%	5,628	1	0.02	23	0.40	23	**0.42**			
(36)	2009	5,695	100%	5,695	1	0.01	17	0.30	18	**0.31**			
(37)	2010	5,783	100%	5,783			14	0.24	14	**0.24**			
(38)	2011	5,864	100%	5,864			9	0.15	9	**0.15**			
(39)	2012	5,946	100%	5,946			9	0.15	9	**0.15**			
(40)	2013	6,029	100%	6,029			9	0.14	9	**0.14**			
(41)	2014	6,114	100%	6,114			8	0.13	8	**0.13**			
(42)	2015	6,199	100%	6,199			8	0.12	8	**0.12**			
(43)	2016	6,286	100%	6,286			6	0.09	6	**0.09**			
(44)	2017	6,374	100%	6,374			4	0.07	4	**0.07**			
(45)	2018	6,463	100%	6,463			1	0.02	1	**0.02**			
(46)	2019	6,554	100%	6,554			1	0.01	1	**0.01**			
(47)	2020	6,646	100%	6,646			0	0.00	0	**0.00**			
(48)	2021	6,739	100%	6,739			0	0.00	0	**0.00**			
(49)	2022	6,833	100%	6,833			0	0.00	0	**0.00**			
(50)	2023	6,929	100%	6,929			0	0.00	0	**0.00**			
(51)	2024	7,026	100%	7,026			0	0.00	0	**0.00**			
(52)	2025	7,124	100%	7,124			0	0.00	0	**0.00**			
(53)	2026	7,224	100%	7,224			0	0.00	0	**0.00**			
(54)	2027	7,325	100%	7,325			0	0.00	0	**0.00**			
(55)	2028	7,427	100%	7,427			0	0.00	0	**0.00**			
(56)	2029	7,531	100%	7,531			0	0.00	0	**0.00**			

Column Notes:
(1) Annual totals for 1998-2002 Reconciliations, monthly for 2003-2004; annual thereafter.
(2) Per June 3, 1996 Integrated Least Cost Plan Update. Includes incremental DSM.
(3) Per Utility Restructuring Act of 1996, pages 24 and 25. Assumes 100% Retail Access as of 1/1/98.
(4) Column (2) x Column (3).
(5) See Schedule 1, Page 2, Column (7).
(6) Column (5)/Column (4) x 100.
(7) See Schedule 1, Page 3, Column (18).
(8) Column (7)/Column (4) x 100.
(9) Column (5) + Column (7).
(10) Column (9) / Column (4) x 100.
(11) The $5 million payment was paid to Narragansett in December 2000 to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.

New England Power Company
Summary of Contract Termination Charges
The Narragansett Electric Company Share (22.4%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	1998	11.3	45.3		0.3	56.9	(51.4)	5.4
(2)	1999	23.9	146.6	21.4	1.2	193.1	(154.3)	38.8
(3)	2000	11.9	151.1		1.2	164.2	(154.3)	9.9
(4)	2001	5.5	0.0		1.1	6.6	(5.3)	1.4
(5)	2002	5.0	0.0		1.1	6.1	(4.8)	1.3
(6)	January	0.4	0.0		0.1	0.5	(0.4)	0.1
(7)	February	0.4	0.0		0.1	0.5	(0.4)	0.1
(8)	March	0.4	0.0		0.1	0.5	(0.4)	0.1
(9)	April	0.4	0.0		0.1	0.5	(0.4)	0.1
(10)	May	0.4	0.0		0.1	0.5	(0.4)	0.1
(11)	June	0.4	0.0		0.1	0.5	(0.4)	0.1
(12)	July	0.4	0.0		0.1	0.5	(0.4)	0.1
(13)	August	0.4	0.0		0.1	0.5	(0.4)	0.1
(14)	September	0.4	0.0		0.1	0.5	(0.4)	0.1
(15)	October	0.4	0.0		0.1	0.5	(0.4)	0.1
(16)	November	0.4	0.0		0.1	0.5	(0.4)	0.1
(17)	December	0.4	0.0		0.1	0.5	(0.4)	0.1
(18)	2003	4.6	0.0		1.0	5.6	(4.4)	1.2
(19)	January	0.3	0.0		0.1	0.4	(0.3)	0.1
(20)	February	0.3	0.0		0.1	0.4	(0.3)	0.1
(21)	March	0.3	0.0		0.1	0.4	(0.3)	0.1
(22)	April	0.3	0.0		0.1	0.4	(0.3)	0.1
(23)	May	0.3	0.0		0.1	0.4	(0.3)	0.1
(24)	June	0.3	0.0		0.1	0.4	(0.3)	0.1
(25)	July	0.3	0.0		0.1	0.4	(0.3)	0.1
(26)	August	0.3	0.0		0.1	0.4	(0.3)	0.1
(27)	September	0.3	0.0		0.1	0.4	(0.3)	0.1
(28)	October	0.3	0.0		0.1	0.4	(0.3)	0.1
(29)	November	0.3	0.0		0.1	0.4	(0.3)	0.1
(30)	December	0.3	0.0		0.1	0.4	(0.3)	0.1
(31)	2004	4.2	0.0		1.0	5.1	(4.0)	1.1
(32)	2005	4	0		1	5	(4)	1
(33)	2006	3	0		1	4	(3)	1
(34)	2007	3	0		1	4	(3)	1
(35)	2008	3	0		1	3	(2)	1
(36)	2009	2	0		1	3	(2)	1
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
Columns (2) through (5) represent 22.4% of the same Column number on Schedule 1, Page 12.
(7) Column (5) + Column (6).

New England Power Company
Summary of Contract Termination Charges

The Narragansett Electric Company Share (22.4%)
Variable Component
$ in Millions

Line	Year End	Nuclear Decommissioning and Other Post-Shutdown Costs	Power Contracts: Power Total Obligation	Power Contracts: Assumed Market Value	Power Contracts: Net: Excess Over Market	Future Power Contract Buyouts	Credit for Unit Sales Contracts: Power Total Obligation	Credit for Unit Sales Contracts: Assumed Market Value	Credit for Unit Sales Contracts: Net: Excess Over Market	Above Market Fuel Transportation Costs	Transmission in Support of Remote Generating Units	Payments in Lieu of Property Taxes	Employee Severance and Retraining Costs	Damages, Costs, or Net Recoveries from Claims	PBR for Nuclear Units Remaining After Market Valuation	**Base Total Variable Component**	Reconciliation Account	**Total Variable Component Including Reconciliation Account**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	**(16)**	(17)	**(18)**
(1)	**1998**	**5.3**	**0.0**	**0.0**	**0.0**	**13.6**	**(0.5)**	**(0.4)**	**(0.1)**	**0.0**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**19.0**	**0.0**	**19.0**
(2)	**1999**	**12.5**	**0.0**	**0.0**	**0.0**	**40.8**	**(1.7)**	**(1.2)**	**(0.5)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.1**	**(12.6)**	**40.5**
(3)	**2000**	**10.6**	**0.0**	**0.0**	**0.0**	**40.7**	**(1.6)**	**(1.2)**	**(0.4)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**51.2**	**(1.5)**	**49.7**
(4)	**2001**	**12.7**	**0.0**	**0.0**	**0.0**	**40.5**	**(0.4)**	**(0.2)**	**(0.2)**	**0.0**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**53.3**	**(13.1)**	**40.2**
(5)	**2002**	**10.1**	**0.0**	**0.0**	**0.0**	**40.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**50.5**	**(16.6)**	**33.8**
(6)	January	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(7)	February	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(8)	March	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(9)	April	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(10)	May	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(11)	June	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(12)	July	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(13)	August	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(14)	September	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(15)	October	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(16)	November	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(17)	December	0.5	0.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	(0.7)	**2.9**
(18)	**2003**	**6.3**	**0.0**	**0.0**	**0.0**	**37.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**43.7**	**(8.8)**	**34.9**
(19)	January	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(20)	February	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(21)	March	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(22)	April	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(23)	May	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(24)	June	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(25)	July	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(26)	August	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(27)	September	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(28)	October	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(29)	November	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(30)	December	0.5	0.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5	(0.8)	**2.7**
(31)	**2004**	**6.5**	**0.0**	**0.0**	**0.0**	**35.6**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**42.1**	**(9.6)**	**32.5**
(32)	2005	6	23	13	9	26	0	0	0	0	0	0	0	0	0	**42**	(7)	**35**
(33)	2006	8	28	16	11	22	0	0	0	0	0	0	0	(4)	0	**37**	(2)	**35**
(34)	2007	7	28	15	12	2	0	0	0	0	0	0	0	0	0	**21**	0	**21**
(35)	2008	6	27	12	15	1	0	0	0	0	0	0	0	0	0	**22**	0	**23**
(36)	2009	5	19	9	10	1	0	0	0	0	0	0	0	0	0	**17**	0	**17**
(37)	2010	5	17	9	9	0	0	0	0	0	0	0	0	0	0	**14**	0	**14**
(38)	2011	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(39)	2012	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	1	**9**
(40)	2013	0	17	8	8	0	0	0	0	0	0	0	0	0	0	**8**	0	**9**
(41)	2014	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(42)	2015	0	17	9	8	0	0	0	0	0	0	0	0	0	0	**8**	(0)	**8**
(43)	2016	0	11	5	6	0	0	0	0	0	0	0	0	0	0	**6**	(0)	**6**
(44)	2017	0	9	4	4	0	0	0	0	0	0	0	0	0	0	**4**	(0)	**4**
(45)	2018	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(46)	2019	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**	(0)	**1**
(47)	2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	**0**

Column Notes:

Columns (2) through (16) represent 22.4% of the same Column number on Schedule 1, Page 15.
(17) See Schedule 2, Page 3, Column (6) x -1
(18) Column (16) + Column (17)

NO ADJUSTMENTS

New England Power Company's Generation Facilities
Net Capability and Unrecovered Costs
Based Upon Actuals

Source	Location	Year(s) Placed In-Service	Energy Source	Net Capability (MW)	$ Millions 1995		$ Millions Sept 1, 1998 *		Applicable Annual Depreciation per W-95 (S) for the period: 1997	Applicable Annual Depreciation per W-95 (S) for the period: 1998 and Beyond	
(1)	(2)	(3)	(4)	(5)	(6)		(7)		(8)	(9)	
Fossil Fuel Units											
Brayton Point Station											
Units 1,2 & 3	Somerset, Mass.	1963-1969	Coal-Oil-Gas	1,130							
Unit 4		1974	Oil-Gas	446							
				1,576							
Salem Harbor Station											
Units 1,2 & 3	Salem, Mass.	1952-1958	Coal-Oil	314							
Unit 4		1972	Oil	400							
				714							
Other System Units	Me., Mass.	1963-1978	Oil	101							
Subtotal Brayton Point, Salem Harbor, and Other				2,391	$435		$353		$34.2	$34.2	(c)
Manchester St. Station	Prov., R.I.	1995	Oil-Gas	513	460	(a)	400	(a)	17.1	17.1	(d)
Hydroelectric Units											
Conventional	Mass., N.H. & Vt.	1909-1987	Water	577	169		150		3.7	3.7	
Pumped Storage											
Bear Swamp	Rowe, Mass.	1974	Water	589	73		65		1.8	1.8	
Nuclear Units											
Vermont Yankee	Vermont	1972	Nuclear	341	73	(b)	27	(b)	6.2	6.2	(e)
Millstone 3	Waterford, Conn.	1986	Nuclear	140	390	(b)	338	(b)	30.0	44.9	(f)
Seabrook 1	Seabrook, N.H.	1990	Nuclear	115	63	(b)	41	(b)	1.9	1.9	
Step-Up Transformers at Generation Facilities (Not Included in Transmission Rates)					12		10		0.4	0.4	
General Plant Allocated to Generation					10		8		0.3	0.3	
Generation Related Property Held For Future Use and Non-Utility Property					11		10		0.0	0.0	
Nantucket Generating Units (Not included in Transmission Rates)					0		0		0.0	0.0	
Total				**4,666**	**$1,695**		**$1,404**		**$95.6**	**$110.5**	

Notes:
(a) Includes prepaid taxes in accordance with tax treaty.
(b) Includes balances for final fuel core and materials and supplies.
(c) Depreciation includes dismantlement expense of $5 M and $3 M for Brayton Point and Salem Harbor, respectively, through the year 2004.
(d) Includes $3.3 M of annual amortization of prepaid taxes which ends 2002.
(e) Depreciation based upon years remaining under license. Vermont Yankee license expires 2012.
(f) Millstone 3 base amortization was adjusted for acceleration per W-95S in 1996 and 1997. Accelerated amortization for 1998. is as noted in the table and an additional $1.2 M of amortization should be added each year thereafter until fully depreciated.

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company Generation Related
Regulatory Asset Balances
$ in Millions

	Balance as of December 31, 1995	Balance as of Sept 1, 1998 *	Applicable Annual Depreciation per W-95 (S) for the period: 1997	Applicable Annual Depreciation per W-95 (S) for the period: 1998 and Beyond	Basis for Deferral
	(1)	(2)	(3)	(4)	(5)
FAS 109	$28	$21	0.9	0.9	FERC Ratemaking Policy
Unamortized Losses on Reacquired Debt	26	23	1.8	1.8	FERC Ratemaking Policy
Pipeline Demand Charges	58	49	2.3	2.3	Settlement Agreement (1)
NEEI	226	130	18.0	21.2	Settlement Agreement (2)
FAS 106 Deferral	13	1	11.0	0.0	FERC Ratemaking Policy
Power Contract Buyouts	24	16	3.9	3.9	Settlement Agreement (3)
Property Losses	5	0	0.0	0.0	Settlement Agreement (2)
Rate Clauses	5	3	0.7	0.7	Settlement Agreement (4)
South Street Cost of Removal	8	2	3.9	0.0	Settlement Agreement (3)
Brayton Point Rotor	9	2	4.2	0.0	Settlement Agreement (3)
Seabrook Tax True-Up	2	2	0.0	0.0	Settlement Agreement (2)
Decontamination & Decommissioning Costs	2	3	0.2	0.2	FERC Ratemaking Policy
W-95S Adjustment Account	2	(10)	0.3	0.0	Settlement Agreement (3)
Unamortized ITC	(23)	(21)	(1.2)	(1.2)	FERC Ratemaking Policy
Total Regulatory Assets	**$384**	**$222**	**$46.0**	**$29.9**	

Settlement Agreement Notes:

(1) W-92 Settlement Agreement - FERC Docket Nos. ER91-565-000 and ER91-566-000
(2) W-9 Settlement Agreement - FERC Docket No. ER88-86-000
(3) W-95 Settlement Agreement - FERC Docket Nos. ER95-267-000
(4) Surcharge Compliance Filing Settlement, FERC Docket Nos. ER88-630-000 et al. (Rate W-10), ER89-582-000 et al. (Rate W-11), and ER90-525-000 et al. (Rate W-12)

* September 1, 1998 balances are based upon the June 30, 1997 balances amortized in accordance with the Pre-Divestiture Schedule 1.

NO ADJUSTMENTS

New England Power Company

FAS 106 Transition Obligation Regulatory Asset

$ in Millions

Unrecovered Balance as of 9/1/98 per Pre-Divestiture	$61.5	
Less: Unrecognized Gain/(Loss) Allocated to Generation	25.4	(a)
Unrecovered Balance as of 9/1/98	**$36.1**	
Actuarial Discount Rate	6.75%	
Amortization (straightline)	11.3	years

Line		Amortization (1)	Interest (2)	Total Expense (3)	Unamortized Balance (4)
(1)	**Unrecovered Balance as of 9/1/98**				**36.1**
(2)	**1998**	**1.1**	**2.4**	**3.5**	**35.1**
(3)	**1999**	**3.2**	**2.3**	**5.4**	**31.9**
(4)	**2000**	**3.2**	**2.0**	**5.2**	**28.7**
(5)	**2001**	**3.2**	**1.8**	**5.0**	**25.5**
(6)	**2002**	**3.2**	**1.6**	**4.8**	**22.3**
(7)	**2003**	**3.2**	**1.4**	**4.6**	**19.1**
(8)	**2004**	**3.2**	**1.2**	**4.4**	**15.9**
(9)	2005	3.2	1.0	**4.2**	12.8
(10)	2006	3.2	0.8	**3.9**	9.6
(11)	2007	3.2	0.5	**3.7**	6.4
(12)	2008	3.2	0.3	**3.5**	3.2
(13)	2009	3.2	0.1	**3.3**	0.0
		36.1			

Column Notes:
(1) Column (4), line (1)/11.33.
(2) (Prior year Column (4) + Current year Column (4))/2 x .0675
(3) Column (1) + Column (2).
(4) Prior year Column (4) - Column (1).

New England Power Company Share of Total Nuclear Post-Shutdown Costs

Based Upon Original Estimates

$ in Millions

	Millstone 3 (1)	Seabrook 1 (2)	Vermont Yankee (3)	Total (4)
1998	0	0	0	**0**
1999	0	0	0	**0**
2000	0	0	0	**0**
2001	7	6	7	**20**
2002	0	6	7	**13**
2003	0	0	0	**0**
2004	0	0	0	**0**
2005	0	0	0	**0**
2006	0	0	0	**0**
2007	0	0	0	**0**
2008	0	0	0	**0**
2009	0	0	0	**0**
2010	0	0	0	**0**
2011	0	0	0	**0**
2012	0	0	0	**0**
2013	0	0	0	**0**
2014	0	0	0	**0**
2015	0	0	0	**0**
2016	0	0	0	**0**
2017	0	0	0	**0**
2018	0	0	0	**0**
2019	0	0	0	**0**
2020	0	0	0	**0**
2021	0	0	0	**0**
2022	0	0	0	**0**
2023	0	0	0	**0**
2024	0	0	0	**0**
2025	0	0	0	**0**
2026	0	0	0	**0**
2027	0	0	0	**0**
2028	0	0	0	**0**
2029	0	0	0	**0**

Column Notes:
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(3) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

New England Power Company Share of Total Annual Decommissioning Cost

Based Upon Revised Estimates

$ in Millions

	Millstone 3 (1)	**Seabrook 1** (2)	**Connecticut Yankee** (3)	**Vermont Yankee** (4)	**Maine Yankee** **(5)**	**Yankee Atomic** (6)	**Total Nuclear Decommissioning** (7)
Sept 1, 1998	0	0	8	1	9	5	**24**
1999	1	1	17	2	19	15	**56**
2000	2	2	16	3	17	8	**48**
2001	2	2	15	3	16	0	**37**
2002	0	2	13	3	14	0	**32**
2003	0	0	13	0	15	0	**28**
2004	0	0	13	0	16	0	**29**
2005	0	0	13	0	16	0	**29**
2006	0	0	19	0	12	4	**35**
2007	0	0	17	0	12	4	**32**
2008	0	0	14	0	10	4	**28**
2009	0	0	14	0	7	4	**25**
2010	0	0	14	0	6	4	**24**
2011	0	0	0	0	0	0	**0**
2012	0	0	0	0	0	0	**0**
2013	0	0	0	0	0	0	**0**
2014	0	0	0	0	0	0	**0**
2015	0	0	0	0	0	0	**0**
2016	0	0	0	0	0	0	**0**
2017	0	0	0	0	0	0	**0**
2018	0	0	0	0	0	0	**0**
2019	0	0	0	0	0	0	**0**
2020	0	0	0	0	0	0	**0**
2021	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	**0**

Column Notes
(1) Estimates for 2002 and beyond have been adjusted to reflect the sale of Millstone 3.
(2) Estimates for 2003 and beyond have been adjusted to reflect the sale of Seabrook 1.
(4) Estimates for 2003 and beyond have been adjusted to reflect the sale of Vermont Yankee.

Columns (3), (5), and (6) reflect permanent shutdown of Connecticut Yankee, Maine Yankee, and Yankee Atomic units and thus include both post-shutdown and decommissioning costs.

Power Contract Buyout Payments Associated with Divestiture
Per IPP Transfer Agreement

$ Millions

	Milford Power	Ridgewood	Resco Saugus	Wheelabrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	Total
2005	34.7	5.5	16.8	26.6	3.3	0.1	0.1	14.0	101.1
2006	40.1	7.7	22.8	35.1	4.3		0.2	13.5	123.7
2007	40.0	7.8	23.2	35.7	4.2		0.0	12.3	123.2
2008	37.2	8.0	23.6	36.4	4.0			11.6	120.7
2009	2.7	8.2	24.0	37.0	3.8			11.2	86.9
2010		0.7	24.4	37.7	3.7			10.9	77.4
2011			24.8	38.4	3.5			10.6	77.3
2012			24.2	39.2				10.3	73.7
2013			25.7	39.9				10.0	75.6
2014			26.1	40.7				9.7	76.5
2015			26.6	41.5				7.5	75.6
2016				42.3				6.4	48.8
2017				31.9				6.2	38.1
2018								6.0	6.0
2019								5.0	5.0
2020								1.2	1.2

Power Contract Obligations
Estimated Market Value

Based Upon Revised Estimates

$'s in millions

	Milford Power	Ridgewood	Resco Saugus	Wheelebrator Millbury	Lawrence Hydro	MWRA Cosgrove	Four Hills Landfill	Hydro Quebec	TOTAL
2005	13.2	5.7	14.6	21.0	4.2	0.0	0.1	1.4	**60.2**
2006	10.4	8.2	19.6	26.5	6.2		0.3	1.3	**72.4**
2007	10.6	7.6	18.6	24.9	5.8		0.0	1.2	**68.7**
2008	8.8	5.9	14.8	19.4	4.7			1.2	**54.8**
2009	0.2	5.3	13.4	17.4	4.2			1.1	**41.6**
2010		0.5	14.2	18.5	4.4			1.1	**38.8**
2011			14.7	19.1	4.6			1.1	**39.4**
2012			15.4	20.0				1.0	**36.4**
2013			16.0	20.7				1.0	**37.7**
2014			16.9	22.1				1.0	**40.0**
2015			17.6	22.9				0.8	**41.2**
2016				23.2				0.6	**23.9**
2017				17.7				0.6	**18.3**
2018								0.6	**0.6**
2019								0.5	**0.5**
2020								0.1	**0.1**

New England Power Company
Annual Utility Unit Sales Power Contracts

Based Upon Original Estimates

$ in Millions

	OSP (1)	Maine Yankee (2)	Millstone 3 (3)	Millstone3/ Seabrook 1 (4)	**TOTAL** (5)
1997	5	0	1	5	**12**
1998	0	1	1	5	**7**
1999	0	0	1	6	**8**
2000	0	1	1	6	**7**
2001	0	1	1		**2**
2002	0	0	0		**0**
2003	0	0	0		**0**
2004	0	0	0		**0**
2005	0	0	0		**0**
2006	0	0	0		**0**
2007	0				**0**
2008	0				**0**
2009	0				**0**
2010	0				**0**

Column Notes:

Estimates have been set to zero. Actual unit sales are reflected in the Nuclear PBR.

NO ADJUSTMENTS

New England Power Company
Fixed Costs of Gas Transportation
Contractual Commitments

Based Upon Original Estimates

Annual Expenses

$ in Millions

	Total Pipeline Demand Charge Obligation (1)	Assumed by USGen NE (2)	Excess (3)	Total Energy Enterprise Minimum Payments (4)	Assumed by USGen NE (5)	Excess (6)	**Total Above Market Fuel Transportation Costs (7)**
Sept 1, 1998	31	31	0	6	6	0	**0**
1999	60	60	0	13	13	0	**0**
2000	60	60	0	13	13	0	**0**
2001	59	59	0	14	14	0	**0**
2002	58	58	0	14	14	0	**0**
2003	57	57	0	15	15	0	**0**
2004	56	56	0	13	13	0	**0**
2005	55	55	0	14	14	0	**0**
2006	54	54	0	14	14	0	**0**
2007	41	41	0	14	14	0	**0**
2008	40	40	0	15	15	0	**0**
2009	35	35	0	15	15	0	**0**
2010	35	35	0	16	16	0	**0**
2011	34	34	0	1	1	0	**0**
2012	30	30	0	0	0	0	**0**
2013	29	29	0	0	0	0	**0**
2014	16	16	0	0	0	0	**0**

Columns Notes:

(2) All payments assumed by USGen NE.
(3) Column (1) - Column (2).
(5) All payments assumed by USGen NE.
(6) Column (4) - Column (5).
(7) Column (3) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges

New England Power Company (100%)
Fixed Component

$ in Millions

Line	Year (1)	Pre-Tax Return on Generation Related Investment and Regulatory Assets (2)	Amortization of Generation Related Investment and Regulatory Assets (3)	Additional Amortization	Generation Related FAS 106 Transition Obligation (4)	**Base Total Fixed Component (5)**	Adjustment For Residual Value Credit (6)	**Net Fixed Component Including Adjustment For Residual Value Credit (7)**
(1)	**1998**	**50.5**	**202.2**		**1.2**	**253.8**	**NA**	**253.8**
(2)	**1999**	**106.6**	**654.0**	**95.5**	**5.4**	**861.5**	**NA**	**861.5**
(3)	**2000**	**53.1**	**674.3**		**5.2**	**732.6**	**NA**	**732.6**
(4)	**2001**	**24.5**	0.0		**5.0**	**29.6**	**NA**	**29.6**
(5)	**2002**	**22.4**	0.0		**4.8**	**27.2**	**NA**	**27.2**
(6)	January	1.7	0.0		0.4	**2.1**	NA	**2.1**
(7)	February	1.7	0.0		0.4	**2.1**	NA	**2.1**
(8)	March	1.7	0.0		0.4	**2.1**	NA	**2.1**
(9)	April	1.7	0.0		0.4	**2.1**	NA	**2.1**
(10)	May	1.7	0.0		0.4	**2.1**	NA	**2.1**
(11)	June	1.7	0.0		0.4	**2.1**	NA	**2.1**
(12)	July	1.7	0.0		0.4	**2.1**	NA	**2.1**
(13)	August	1.7	0.0		0.4	**2.1**	NA	**2.1**
(14)	September	1.7	0.0		0.4	**2.1**	NA	**2.1**
(15)	October	1.7	0.0		0.4	**2.1**	NA	**2.1**
(16)	November	1.7	0.0		0.4	**2.1**	NA	**2.1**
(17)	December	1.7	0.0		0.4	**2.1**	NA	**2.1**
(18)	**2003**	**20.4**	**0.0**		**4.6**	**25.0**	**NA**	**25.0**
(19)	January	1.5	0.0		0.4	**1.9**	NA	**1.9**
(20)	February	1.5	0.0		0.4	**1.9**	NA	**1.9**
(21)	March	1.5	0.0		0.4	**1.9**	NA	**1.9**
(22)	April	1.5	0.0		0.4	**1.9**	NA	**1.9**
(23)	May	1.5	0.0		0.4	**1.9**	NA	**1.9**
(24)	June	1.5	0.0		0.4	**1.9**	NA	**1.9**
(25)	July	1.5	0.0		0.4	**1.9**	NA	**1.9**
(26)	August	1.5	0.0		0.4	**1.9**	NA	**1.9**
(27)	September	1.5	0.0		0.4	**1.9**	NA	**1.9**
(28)	October	1.5	0.0		0.4	**1.9**	NA	**1.9**
(29)	November	1.5	0.0		0.4	**1.9**	NA	**1.9**
(30)	December	1.5	0.0		0.4	**1.9**	NA	**1.9**
(31)	**2004**	**18.5**	**0.0**		**4.4**	**22.9**	**NA**	**22.9**
(32)	2005	17	0		4	**21**	NA	**21**
(33)	2006	15	0		4	**19**	NA	**19**
(34)	2007	13	0		4	**17**	NA	**17**
(35)	2008	11	0		4	**15**	NA	**15**
(36)	2009	9	0		3	**13**	NA	**13**
(37)	2010							
(38)	2011							
(39)	2012							
(40)	2013							
(41)	2014							
(42)	2015							
(43)	2016							
(44)	2017							
(45)	2018							
(46)	2019							
(47)	2020							
(48)	2021							
(49)	2022							
(50)	2023							
(51)	2024							
(52)	2025							
(53)	2026							

Column Notes:
(1) Annual totals for 1998 - 2002 Reconciliations, monthly for 2003-2004; annual thereafter
(2) See Schedule 1, Page 14, Column (9).
(3) For years 1998-1999 Column (3) = [Schedule 1, Page 1, Column (10) x Schedule 1, Page 1, Column (4)]/100/.224 - Schedule 1, Page 15, Column (16) - Schedule 1, Page 12, Columns (2) and (4).
For 2000, Column (3) = Page 14, Column (2).
(4) Schedule 1, Page 5a, Column (3) x Page 1, Column (3).
(5) Sum of Columns (2) through (4).
(6) Not applicable at NEP level. See Schedule 1, Page 2, Column (6) for Narragansett Residual Value Credit.
(7) Column (5) + Column (6).

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Deferred Taxes on Fixed Component

$ in Millions

		Book Basis			Tax Basis				
Line	Year End (1)	Balance Net Book Value of Generation (2)	Balance Generation Related Regulatory Assets (3)	Total Net Book Basis (4)	Balance Net Book Value of Generation (5)	Balance Generation Related Regulatory Assets (6)	**Total Tax Basis** (7)	**Excess Book Over Tax (8)**	**Deferred Taxes (9)**
Pre-Divest End Balances		**$1,435**	**$202**	**$1,636**	**$696**				
Less: Maine Yankee and ITC		31	(20)	10	14				
Post-Divest Start Balances		$1,404	$222	$1,626	$682				
(1)	**Sept 1, 1998**	**1,404**	**222**	**1,626**	**682**	**0**	**682**	**944**	**370**
(2)	**1998**	**1,229**	**195**	**1,424**	**652**	**0**	**652**	**771**	**303**
(3)	**1999**	**582**	**92**	**674**	**571**	**0**	**571**	**103**	**40**
(4)	**2000**	**0**	**0**	**0**	**521**	**0**	**521**	**(521)**	**(204)**
(5)	**2001**	**0**	**0**	**0**	**475**	**0**	**475**	**(475)**	**(186)**
(6)	**2002**	**0**	**0**	**0**	**433**	**0**	**433**	**(433)**	**(170)**
(7)	**2003**	**0**	**0**	**0**	**395**	**0**	**395**	**(395)**	**(155)**
(8)	**2004**	**0**	**0**	**0**	**357**	**0**	**357**	**(357)**	**(140)**
(9)	2005	0	0	0	320	0	**320**	**(320)**	**(125)**
(10)	2006	0	0	0	282	0	**282**	**(282)**	**(111)**
(11)	2007	0	0	0	246	0	**246**	**(246)**	**(96)**
(12)	2008	0	0	0	209	0	**209**	**(209)**	**(82)**
(13)	2009	0	0	0	175	0	**175**	**(175)**	**(69)**

Column Notes:
(2) See Pre-Divestiture Schedule 1, for August 31,1998 balances. For year end 1997-2009, Column (2) prior year - (Schedule 1, Page 12, Column (3) current year x (Column (2) Line1/Column (4) Line 1).
(3) See Pre-Divestiture Schedule 1, for August 31,1988 balances. For year end 1997-2009, Column (3) prior year-(Schedule 1, Page 12, Column (3) current year x (Column (3) Line1/Column (4) Line 1).
(4) Column (2) + Column (3).
(5) Per tax records of the Company.
(6) Per tax records of the Company.
(7) Column (5) + Column (6).
(8) Column (4) - Column (7).
(9) Column (8) x tax rate of .39225.

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Return on Fixed Component

		Base Return							
Line	Year End (1)	Balance of Fixed Component (2)	Deferred Taxes (3)	Net Balance (4)	Average Net Balance (5)	Subtotal Annual Return on Unamortized Balance (6)	Less: Return on Rate Clauses (7)	Plus: Return on Unamortized ITC (8)	Total Annual Return on Unamortized Balance (9)
(1)	Sept 1, 1998	$1,626	$370	$1,256					
(2)	**1998**	**1,424**	**303**	**1,121**	**$1,188**	**$50**	**($0.1)**	**$0.8**	**$50**
(3)	**1999**	**674**	**40**	**634**	**837**	**105**	**(0.1)**	**1.6**	**107**
(4)	**2000**	**0**	**(204)**	**204**	**419**	**53**	**(0.0)**	**0.5**	**53**
(5)	**2001**	**0**	**(186)**	**186**	**195**	**25**	**0.0**	**0.0**	**25**
(6)	**2002**	**0**	**(170)**	**170**	**178**	**22**	**0.0**	**0.0**	**22**
(7)	**2003**	**0**	**(155)**	**155**	**162**	**20**	**0.0**	**0.0**	**20**
(8)	**2004**	**0**	**(140)**	**140**	**148**	**19**	**0.0**	**0.0**	**19**
(9)	2005	0	(125)	125	133	17	0.0	0.0	**17**
(10)	2006	0	(111)	111	118	15	0.0	0.0	**15**
(11)	2007	0	(96)	96	104	13	0.0	0.0	**13**
(12)	2008	0	(82)	82	89	11	0.0	0.0	**11**
(13)	2009	0	(69)	69	75	9	0.0	0.0	**9**

Column Notes:
(2) See Schedule 1, Page 13, Column (4).
(3) See Schedule 1, Page 13, Column (9).
(4) Column (2) - Column (3).
(5) (Column (4) Prior Year + Column (4))/2.
(6) Column (5) x Total Pre-Valuation Rate of Return of 11.01% x Schedule 1, Page 1, Column (3).
(7) Average of (Unamortized Balance of Rate Clauses - Deferred Taxes on Rate Clauses) x 11.18% x Page 1, Column (3).
(8) Average of Unamortized Balance of ITC x 11.18% x Page 1, Column (3).
(9) Column (6) + Column (7) + Column (8).

Note: Savings from refinancing calculated as difference between 12.56% and 12.16% are included in the Reconciliation Account.

* Actual September 30, 1998 capital structure with pro-forma adjustments for known preferred stock redemptions which occurred in October and November.

Return Component	*BASE* Post-Divestiture Year End <u>1995</u>	*REFINANCED* Post-Divestiture September * <u>1998</u>
Capital Structure:		
LTD	44.07%	42.44%
Preferred	3.56%	0.21%
Common Equity	52.37%	57.35%
	100.00%	100.00%
Cost Rates:		
LTD	6.23%	4.15%
Preferred	5.69%	6.00%
Common Equity	11.00%	11.00%
Total Weighted Cost Rate	**8.71%**	**8.08%**
Reimbursement for Taxes on Equity Component	**3.85%**	**4.08%**
Total Rate of Return	**12.56%**	**12.16%**

NO ADJUSTMENTS

Summary of Contract Termination Charges
New England Power Company (100%)

Variable Component

$ in Millions

			Power Contracts				Credit for Unit Sales Contracts									
Line	Year End (1)	Nuclear Decommissioning and Other Post-Shutdown Costs (2)	Total Obligation (3)	Assumed Market Value (4)	Excess Over Market (5)	Future Power Contract Buyouts (6)	Total Revenue (7)	Assumed Market Value (8)	Excess Over Market (9)	Above Market Fuel Transportation Costs (10)	Transmission in Support of Remote Generating Units (11)	Payments in Lieu of Property Taxes (12)	Employee Severance and Retraining Costs (13)	Damages, Costs, or Net Recoveries from Claims (14)	PBR for Nuclear Units Remaining After Market Valuation (15)	**Base Total Variable Component (16)**
(1)	**1998**	**23.8**	**0.0**	**0.0**	**0.0**	**60.8**	**(2.4)**	**(1.9)**	**(0.5)**	**0.0**	**0.6**	**0.0**	**0.0**	**0.0**	**0.0**	**84.6**
(2)	**1999**	**55.7**	**0.0**	**0.0**	**0.0**	**182.1**	**(7.6)**	**(5.4)**	**(2.2)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.0**
(3)	**2000**	**47.5**	**0.0**	**0.0**	**0.0**	**181.4**	**(7.4)**	**(5.4)**	**(2.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**228.4**
(4)	**2001**	**56.6**	**0.0**	**0.0**	**0.0**	**180.7**	**(1.7)**	**(0.7)**	**(1.0)**	**0.0**	**1.5**	**0.0**	**0.0**	**0.0**	**0.0**	**237.8**
(5)	**2002**	**45.1**	**0.0**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**225.2**
(6)	January	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(7)	February	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(8)	March	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(9)	April	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(10)	May	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(11)	June	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(12)	July	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(13)	August	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(14)	September	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(15)	October	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(16)	November	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(17)	December	2.3	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**16.3**
(18)	**2003**	**28.2**	**0.0**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**195.1**
(19)	January	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(20)	February	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(21)	March	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(22)	April	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(23)	May	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(24)	June	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(25)	July	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(26)	August	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(27)	September	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(28)	October	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(29)	November	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(30)	December	2.4	0.0	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**15.7**
(31)	**2004**	**29.1**	**0.0**	**0.0**	**0.0**	**158.8**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**187.9**
(32)	2005	29	101	60	41	117	0	0	0	0	0	0	0	0	0	**187**
(33)	2006	35	124	72	51	97	0	0	0	0	0	0	0	(17)	0	**166**
(34)	2007	32	123	69	54	7	0	0	0	0	0	0	0	0	0	**93**
(35)	2008	28	121	55	66	6	0	0	0	0	0	0	0	0	0	**100**
(36)	2009	25	87	42	45	6	0	0	0	0	0	0	0	0	0	**75**
(37)	2010	24	77	39	39	0	0	0	0	0	0	0	0	0	0	**62**
(38)	2011	0	77	39	38	0	0	0	0	0	0	0	0	0	0	**38**
(39)	2012	0	74	36	37	0	0	0	0	0	0	0	0	0	0	**37**
(40)	2013	0	76	38	38	0	0	0	0	0	0	0	0	0	0	**38**
(41)	2014	0	77	40	37	0	0	0	0	0	0	0	0	0	0	**37**
(42)	2015	0	76	41	34	0	0	0	0	0	0	0	0	0	0	**34**
(43)	2016	0	49	24	25	0	0	0	0	0	0	0	0	0	0	**25**
(44)	2017	0	38	18	20	0	0	0	0	0	0	0	0	0	0	**20**
(45)	2018	0	6	1	5	0	0	0	0	0	0	0	0	0	0	**5**
(46)	2019	0	5	0	5	0	0	0	0	0	0	0	0	0	0	**5**
(47)	2020	0	1	0	1	0	0	0	0	0	0	0	0	0	0	**1**
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(All Sources based upon estimates of Variable Costs)
(2) (Schedule 1, Page 6, Column (4) + Schedule 1, Page 7, Column (7)) x Schedule 1, Page 1, Column (3).
(5) Column (3) - Column (4).
(6) Per NEP/USGen "IPP Contract Transfer Agreement".
(7) Schedule 1, Page 10, Column (5) x Schedule 1, Page 1, Column (3).
(9) Column (7) - Column (8).
(10) Schedule 1, Page 11, Column (7) x Schedule 1, Page 1, Column (3).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

Reconciliation Adjustment

The Narragansett Electric Company Share

Revenue Adjustments

Line	Year (1)	Estimated Kwh Delivered (2)	Actual Kwh Delivered (3)	Delta Kwh Delivered (4)	Termination Charge Billed (5)	Narragansett Revenue Excess/ (Shortfall) (6)	
(1)	**1998**	**1,626**	**1,669**	**42**	**1.50**	**1.8**	***NO ADJUSTMENTS TO SEPTEMBER***
(2)	**1999**	**5,013**	**5,175**	**162**	**1.58**	**1.9**	
(3)	**2000**	**5,165**	**5,271**	**106**	**1.15**	**1.2**	
(4)	**2001**	**5,183**	**5,387**	**204**	**0.80**	**2.5**	
(5)	**2002**	**5,232**	**5,557**	**325**	**0.67**	**2.5**	
(6)	January	441	509	69	pro-rated	0.4	
(7)	February	441	468	28	**0.68**	0.2	
(8)	March	441	365	(76)	**0.68**	(0.5)	
(9)	April	441	420	(21)	**0.68**	(0.1)	
(10)	May	441	412	(29)	**0.68**	(0.2)	
(11)	June	441	421	(20)	**0.68**	(0.1)	
(12)	July	441	509	69	**0.68**	0.5	
(13)	August	441	661	220	**0.68**	1.5	
(14)	September	441	511	70	**0.68**	0.5	
(15)	October	441	444	4	**0.68**	0.0	
(16)	November	441	439	(1)	**0.68**	(0.0)	
(17)	December	441	488	48	**0.68**	0.3	
(18)	**2003**	**5,288**	**5,648**	**360**	**0.68**	**2.4**	
(19)	January	446	531	85	pro-rated	0.7	
(20)	February	446	487	41	**0.63**	0.3	
(21)	March	446	457	10	**0.63**	0.1	
(22)	April	446	440	(6)	**0.63**	0.0	
(23)	May	446	413	(33)	**0.63**	(0.2)	
(24)	June	446	455	9	**0.63**	0.1	
(25)	July	446	506	60	**0.63**	0.4	
(26)	August	446	527	81	**0.63**	0.5	
(27)	September	446	544	97	**0.63**	0.6	
(28)	October	446	446	0	**0.63**	0.0	
(29)	November	446	446	0	**0.63**	0.0	
(30)	December	446	446	0	**0.63**	0.0	
(31)	**2004**	**5,356**	**5,356**	**344**	**0.63**	**2.3**	
(32)	2005	5,428	5,428	0	0.67	0	
(33)	2006	5,496	5,496	0	0.66	0	
(34)	2007	5,562	5,562	0	0.40	0	
(35)	2008	5,628	5,628	0	0.42	0	
(36)	2009	5,695	5,695	0	0.31	0	
(37)	2010	5,783	5,783	0	0.24	0	
(38)	2011	5,864	5,864	0	0.15	0	
(39)	2012	5,946	5,946	0	0.15	0	
(40)	2013	6,029	6,029	0	0.14	0	
(41)	2014	6,114	6,114	0	0.13	0	
(42)	2015	6,199	6,199	0	0.12	0	
(43)	2016	6,286	6,286	0	0.09	0	
(44)	2017	6,374	6,374	0	0.07	0	
(45)	2018	6,463	6,463	0	0.02	0	
(46)	2019	6,554	6,554	0	0.01	0	
(47)	2020	6,646	6,646	0	0.00	0	
(48)	2021	6,739	6,739	0	0.00	0	
(49)	2022	6,833	6,833	0	0.00	0	
(50)	2023	6,929	6,929	0	0.00	0	
(51)	2024	7,026	7,026	0	0.00	0	
(52)	2025	7,124	7,124	0	0.00	0	
(53)	2026	7,224	7,224	0	0.00	0	
(54)	2027	7,325	7,325	0	0.00	0	
(55)	2028	7,427	7,427	0	0.00	0	
(56)	2029	7,531	7,531	0	0.00	0	

Column Notes:
(2) See Schedule 1, Page 1, Column (2).
(3) Actual Kwh delivered.
(4) Column (3) - Column (2).
(5) See Schedule 1, Page 1, Column (10).
(6) Column (4) x Column (5)/100.

Reconciliation Adjustment

(continued from page 2a)

The Narragansett Electric Company Share

New England Power Company Variable Cost Adjustments

Line		Estimated Base Variable Component (7)	Actual Nuclear Decommissioning Costs (8)	Actual Power Contracts Obligations (9)	Actual Power Contracts Market Value (10)	Actual Power Contract Buyouts (11)	Actual Unit Sales Contracts Revenue (12)	Actual Unit Sales Contracts Market Value (13)	Actual Above Market Fuel Transportation Costs (14)	Actual Transmission in Support of Remote Generating Units (15)	Actual Payments in Lieu of Property Property Taxes (16)	Actual Employee Severance and Retraining Costs (17)	Actual Damages, Costs, or Net Recoveries from Claims (18)	Actual PBR for Nuclear Units Remaining After Market Valuation (19)	Actual Environmental Response Costs (20)	NEP Actual Total Variable Component (21)	Delta Variable Component (22)	Narragansett Share of Delta Variable Component (23)	**Narragansett Annual Reconciliation Adjustment Excess/ (Shortfall) (24)**
(1)	**1998**	**84.6**	**17.2**	**0.0**	**0.0**	**60.8**	**(1.8)**	**(1.6)**	**0.0**	**0.6**	**0.0**	**(17.8)**	**(1.4)**	**6.0**	**0.0**	**65.2**	**(19.4)**	**(4.3)**	**6.1**
(2)	**1999**	**237.0**	**43.8**	**0.0**	**0.0**	**182.1**	**0.0**	**0.0**	**0.0**	**1.2**	**0.0**	**1.4**	**(36.9)**	**17.3**	**0.0**	**208.8**	**(28.1)**	**(6.3)**	**8.2**
(3)	**2000**	**228.4**	**29.9**	**0.0**	**0.0**	**181.4**	**0.0**	**0.0**	**0.0**	**1.4**	**0.0**	**(0.7)**	**(20.8)**	**(17.5)**	**0.0**	**173.7**	**(54.7)**	**(12.3)**	**13.5**
(4)	**2001**	**237.8**	**27.5**	**0.0**	**0.0**	**180.7**	**0.0**	**0.0**	**0.0**	**0.3**	**0.0**	**0.0**	**(3.6)**	**6.2**	**0.8**	**212.0**	**(25.9)**	**(5.8)**	**8.3**
(5)	**2002**	**225.2**	**21.4**	**0.0**	**0.0**	**180.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(1.1)**	**(0.2)**	**0.6**	**1.9**	**202.7**	**(22.5)**	**(5.0)**	**7.5**
(6)	January	16.3	0.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.5)	0.2	14.9	(1.4)	(0.3)	0.7
(7)	February	16.3	2.2	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	17.0	0.8	0.2	0.0
(8)	March	16.3	1.6	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.4	0.1	0.0	(0.5)
(9)	April	16.3	1.5	0.0	0.0	14.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	16.1	(0.2)	(0.0)	(0.1)
(10)	May	16.3	1.6	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	15.7	(0.6)	(0.1)	(0.1)
(11)	June	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.6	0.4	0.1	(0.2)
(12)	July	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.5	0.2	0.1	0.4
(13)	August	16.3	2.9	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4	0.2	0.0	1.5
(14)	September	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	16.7	0.4	0.1	0.4
(15)	October	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.5	0.3	0.1	(0.0)
(16)	November	16.3	3.0	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	16.6	0.3	0.1	(0.1)
(17)	December	16.3	2.7	0.0	0.0	13.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.2	(0.1)	(0.0)	0.3
(18)	**2003**	**195.1**	**27.8**	**0.0**	**0.0**	**166.9**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**(0.4)**	**1.2**	**195.6**	**0.5**	**0.1**	**2.3**
(19)	January	15.7	1.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	15.2	(0.4)	(0.1)	0.8
(20)	February	15.7	3.5	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	16.8	1.1	0.2	0.0
(21)	March	15.7	2.9	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.2	0.5	0.1	(0.1)
(22)	April	15.7	3.0	0.0	0.0	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.1)	0.1	17.2	1.5	0.3	(0.4)
(23)	May	15.7	2.9	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.2	1.5	0.3	(0.5)
(24)	June	15.7	3.0	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.3	1.7	0.4	(0.3)
(25)	July	15.7	3.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	17.3	1.7	0.4	0.0
(26)	August	15.7	3.1	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.1	17.1	1.5	0.3	0.2
(27)	September	15.7	2.5	0.0	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	16.8	1.1	0.2	0.4
(28)	October	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(29)	November	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(30)	December	15.7	**2.8**	0.0	0.0	13.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.1	0.4	0.1	(0.1)
(31)	**2004**	**187.9**	**34.4**	**0.0**	**0.0**	**164.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.7**	**199.2**	**11.3**	**2.5**	**(0.2)**
(32)	2005	187	46	101	60	117	0	0	0	0	0	0	0	0	0	204	17	(6)	6
(33)	2006	166	35	124	72	97	0	0	0	0	0	0	0	0	0	183	17	4	(4)
(34)	2007	93	32	123	69	7	0	0	0	0	0	0	0	0	0	93	0	0	0
(35)	2008	100	28	121	55	6	0	0	0	0	0	0	0	0	0	100	0	0	0
(36)	2009	75	25	87	42	6	0	0	0	0	0	0	0	0	0	75	0	0	0
(37)	2010	62	24	77	39	0	0	0	0	0	0	0	0	0	0	62	0	0	0
(38)	2011	38	0	77	39	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(39)	2012	37	0	74	36	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(40)	2013	38	0	76	38	0	0	0	0	0	0	0	0	0	0	38	0	0	0
(41)	2014	37	0	77	40	0	0	0	0	0	0	0	0	0	0	37	0	0	0
(42)	2015	34	0	76	41	0	0	0	0	0	0	0	0	0	0	34	0	0	0
(43)	2016	25	0	49	24	0	0	0	0	0	0	0	0	0	0	25	0	0	0
(44)	2017	20	0	38	18	0	0	0	0	0	0	0	0	0	0	20	0	0	0
(45)	2018	5	0	6	1	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(46)	2019	5	0	5	0	0	0	0	0	0	0	0	0	0	0	5	0	0	0
(47)	2020	1	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
(48)	2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(49)	2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(50)	2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(51)	2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(52)	2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(53)	2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(54)	2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(55)	2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
(56)	2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						0													

Column Notes:

- (7) See Schedule 1, Page 15, Column (16).
- (8)-(20) Actual expenses incurred.
- (21) Column (8) + Column (9) - Column (10) + Column (11) + Column (12) - Column (13) + Column (14) + Column (15) + Column (16) + Column (17) + Column (18) + Column (19) + Column (20).
- (22) Column (21) - Column (7).
- (23) Column (22) x 22.4%. Includes $10 million credit related to Settlement dated November 14, 2005.
- (24) Schedule 2, Page 2a, Column (6) - Schedule 2, Page 2b, Column (23).

Reconciliation Account

The Narragansett Electric Company

The Narragansett Electric Company Account

Line	Year (1)	Reconciliation Adjustment (2)	Divestiture Related Adjustments per Section 1.1.4 (3)	Annual Shortfall/ (Excess) (4)	Pre-Tax Return on Balance (5)	Collection of Prior Year Balance Including Interest (6)	End of Year Account Balance (7)	Lump Sum Payment/ Narr Deferred Tax Funding (8)	Revised End of Year Account Balance (9)
						As of August 31, 1998	**(3.3)**		
(1)	**1998**	**(6.1)**	**(11.3)**	**(17.5)**	**(0.77)**	**0.0**	**(21.5)**		
(2)	**1999**	**(8.2)**	**(2.7)**	**(10.9)**	**(2.29)**	**12.6**	**(22.1)**	**17.5**	**(4.6)**
(3)	**2000**	**(13.5)**	**(1.5)**	**(12.3)**	**(1.30)**	**1.5**	**(16.7)**	**5.0**	**(11.7)**
(4)	**2001**	**(8.3)**	**(3.8)**	**(12.1)**	**(1.44)**	**13.1**	**(12.2)**		
(5)	**2002**	**(7.5)**	**(2.1)**	**(9.6)**	**(1.04)**	**16.6**	**(6.2)**		
(6)	January	(0.7)	(0.5)	(1.2)	(0.06)	0.7	(6.8)		
(7)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.7	(6.6)		
(8)	March	0.5	(0.5)	(0.0)	(0.07)	0.7	(5.9)		
(9)	April	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.7)		
(10)	May	0.1	(0.5)	(0.4)	(0.06)	0.7	(5.4)		
(11)	June	0.2	(0.5)	(0.3)	(0.05)	0.7	(5.0)		
(12)	July	(0.4)	(0.5)	(0.9)	(0.05)	0.7	(5.2)		
(13)	August	(1.5)	(0.5)	(1.9)	(0.05)	0.7	(6.4)		
(14)	September	(0.4)	(0.5)	(0.9)	(0.07)	0.7	(6.6)		
(15)	October	0.0	(0.5)	(0.4)	(0.07)	0.7	(6.4)		
(16)	November	0.1	(0.5)	(0.4)	(0.07)	0.7	(6.2)		
(17)	December	(0.3)	(0.7)	(1.0)	(0.06)	0.7	(6.5)		
(18)	**2003**	**(2.3)**	**(6.1)**	**(8.4)**	**(0.73)**	**8.8**	**(6.5)**		
(19)	January	(0.8)	(0.5)	(1.3)	(0.07)	0.8	(7.1)		
(20)	February	(0.0)	(0.5)	(0.5)	(0.07)	0.8	(6.8)		
(21)	March	0.1	(0.5)	(0.5)	(0.07)	0.8	(6.6)		
(22)	April	0.4	(0.6)	(0.2)	(0.07)	0.8	(6.1)		
(23)	May	0.5	(0.4)	0.1	(0.06)	0.8	(5.2)		
(24)	June	0.3	(0.5)	(0.2)	(0.05)	0.8	(4.7)		
(25)	July	(0.0)	(0.5)	(0.5)	(0.05)	0.8	(4.4)		
(26)	August	(0.2)	(0.5)	(0.7)	(0.04)	0.8	(4.4)		
(27)	September	(0.4)	(0.5)	(0.9)	(0.04)	0.8	(4.5)		
(28)	October	0.1	(0.5)	(0.4)	(0.05)	0.8	(4.1)		
(29)	November	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.8)		
(30)	December	0.1	(0.5)	(0.4)	(0.04)	0.8	(3.5)		
(31)	**2004**	**0.2**	**(6.1)**	**(5.9)**	**(0.65)**	**9.6**	**(3.5)**		
(32)	2005	(6)	(6)	-12	0	7	-9	10.0	0.7
(33)	2006	4	(4)	0	0	2	3		
(34)	2007	0	(0)	0	0	0	2		
(35)	2008	0	(0)	0	0	0	2		
(36)	2009	0	(0)	0	0	0	1		
(37)	2010	0	0	0	0	0	1		
(38)	2011	0	0	0	0	0	1		
(39)	2012	0	0	0	0	-1	0		
(40)	2013	0	0	0	0	0	0		
(41)	2014	0	0	0	0	0	0		
(42)	2015	0	0	0	0	0	0		
(43)	2016	0	0	0	0	0	0		
(44)	2017	0	0	0	0	0	0		
(45)	2018	0	0	0	0	0	0		
(46)	2019	0	0	0	0	0	0		
(47)	2020	0	0	0	0	0	0		
(48)	2021	0	0	0	0	0	0		
(49)	2022	0	0	0	0	0	0		
(50)	2023	0	0	0	0	0	0		
(51)	2024	0	0	0	0	0	0		
(52)	2025	0	0	0	0	0	0		
(53)	2026	0	0	0	0	0	0		
(54)	2027	0	0	0	0	0	0		
(55)	2028	0	0	0	0	0	0		
(56)	2029	0	0	0	0	0	0		

Column Notes:
(2) See Schedule 2, Page 2b, Column (24) x -1.
(3) See Schedule 2, Page 5.
(4) Sum Columns (2) and (3). September 2000 includes unbilled revenue of $2.7m.
(5) Column (7) prior period (on average for 1/2 year) x 12.16%.
(6) In 1999, collection per 1998 CTC Reconciliation Filing; In 2000, collection represents 1999 balance per 1998 CTC Reconciliation filing plus return calculated based on mid year convention as a result of the lump sum payment. In 2001, Column (9) prior year x -1 + Column (5) current year.
In 2002 - 2029, Column (7) prior year x -1 - Column (5) current year. 2004 reflects unbilled revenue adjustment of $2.8m, 2005 reflects unbilled revenue of $2.6 million.
(7) Prior year Column (7) + current year Sum Column (4) through (6).
(8) The $17.5 million represents lump sum payment made by New England Power Company to The Narragansett Electric Company in December 1999.
The $5 million payment is to reduce Narragansett's deficiency in its reserve for deferred taxes per the Merger Settlement in RIPUC Docket 2930.
The $10 million payment relates to a Settlement Agreement dated November 14, 2005.

Reconciliation Adjustment

New England Power Company (100%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

Line	Year (1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Transaction Costs (16)	TOTAL (17)
(1)	**1998**	**(2.121)**	**(27.968)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.344)**	**0.000**	**0.000**	**(0.620)**	**0.000**	**0.000**	**0.282**	**(30.770)**
(2)	**1999**	**(5.957)**	**0.000**	**(2.000)**	**(1.040)**	**(2.202)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.595)**	**(0.547)**	**0.154**	**(12.188)**
(3)	**2000**	**(5.853)**	**0.000**	**0.245**	**0.000**	**0.007**	**0.000**	**0.000**	**0.000**	**(1.135)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.736)**
(4)	**2001**	**(5.804)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.415)**	**(1.300)**	**(9.607)**	**(0.038)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(17.165)**
(5)	**2002**	**(5.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.078**	**(0.599)**	**(3.090)**	**0.000**	**0.000**	**0.000**	**0.000**	**(9.411)**
(6)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	(0.110)	(1.530)	0.000	0.000	0.000	0.000	(2.121)
(7)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.088)	(1.551)	0.000	0.000	0.000	0.000	(2.121)
(8)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.376)	(1.551)	0.000	0.000	0.000	0.000	(2.410)
(9)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.186)	(1.550)	0.000	0.000	0.000	0.000	(2.218)
(10)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.107)	(1.551)	0.000	0.000	0.000	0.000	(2.141)
(11)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.127)	(1.551)	0.000	0.000	0.000	0.000	(2.161)
(12)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.139)	(1.551)	0.000	0.000	0.000	0.000	(2.173)
(13)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.117)	(1.551)	0.000	0.000	0.000	0.000	(2.151)
(14)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.154)	(1.551)	0.000	0.000	0.000	0.000	(2.188)
(15)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.099)	(1.551)	0.000	0.000	0.000	0.000	(2.133)
(16)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.189)	(1.551)	0.000	0.000	0.000	0.000	(2.223)
(17)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.841)	(1.761)	0.000	0.000	0.000	0.000	(3.085)
(18)	**2003**	**(5.796)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.002**	**(2.531)**	**(18.800)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.125)**
(19)	January	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.184)	(1.551)	0.000	0.000	0.000	0.000	(2.218)
(20)	February	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.172)	(1.551)	0.000	0.000	0.000	0.000	(2.206)
(21)	March	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.406)	(1.551)	0.000	0.000	0.000	0.000	(2.440)
(22)	April	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.192)	(1.939)	0.000	0.000	0.000	0.000	(2.614)
(23)	May	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.165)	(1.322)	0.000	0.000	0.000	0.000	(1.970)
(24)	June	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.191)	(1.551)	0.000	0.000	0.000	0.000	(2.225)
(25)	July	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.216)	(1.551)	0.000	0.000	0.000	0.000	(2.249)
(26)	August	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.176)	(1.551)	0.000	0.000	0.000	0.000	(2.210)
(27)	September	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.193)	(1.551)	0.000	0.000	0.000	0.000	(2.227)
(28)	October	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(29)	November	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(30)	December	(0.483)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.247)	(1.551)	0.000	0.000	0.000	0.000	(2.280)
(31)	**2004**	**(5.792)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.636)**	**(18.771)**	**0.000**	**0.000**	**0.000**	**0.000**	**(27.199)**
(32)	2005	**(5.789)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(2.960)	(18.612)	0.000	0.000	0.000	0.000	(27.361)
(33)	2006	(0.016)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(1.727)	(15.510)	0.000	0.000	0.000	0.000	(17.253)
(34)	2007	(0.013)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.013)
(35)	2008	(0.010)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.010)
(36)	2009	(0.007)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.007)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes operating expense charges.
(17) Sum of columns (2) through (16).

Reconciliation Adjustment

Narragansett Electric Company (22.4%)
Divestiture Related Adjustments (per Section 1.1.4)
($ in millions)

	(1)	Refinancing Savings (2)	Prior Year Settlement Discussions (3)	Gloucester Diesel Sale (4)	Gil/Erving/ Northfield Land Sale (5)	Westerly/ Charlestown Land Sale (6)	Newburyport Diesel Sale (7)	Salz Salt Marsh Land Sale (8)	Millstone 3 Sale (9)	NEEI (10)	Vermont Yankee (11)	Seabrook (12)	NOx ERC to Tiverton (13)	NOx ERC to Haverhill Paperboard (14)	NOx ERC to Cabot Power (15)	Other (16)	TOTAL (17)
(1)	**1998**	**(0.475)**	**(10.718)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.077)**	**0.000**	**0.000**	**(0.139)**	**0.000**	**0.000**	**0.063**	**(11.346)**
(2)	**1999**	**(1.335)**	**0.000**	**(0.448)**	**(0.233)**	**(0.493)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.133)**	**(0.123)**	**0.034**	**(2.731)**
(3)	**2000**	**(1.312)**	**0.000**	**0.055**	**0.000**	**0.002**	**0.000**	**0.000**	**0.000**	**(0.254)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(1.510)**
(4)	**2001**	**(1.301)**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.093)**	**(0.291)**	**(2.153)**	**(0.009)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(3.847)**
(5)	**2002**	**(1.300)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.017**	**(0.134)**	**(0.693)**	**0.000**	**0.000**	**0.000**	**0.000**	**(2.109)**
(6)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.025)	(0.343)	0.000	0.000	0.000	0.000	(0.475)
(7)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.020)	(0.347)	0.000	0.000	0.000	0.000	(0.475)
(8)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.084)	(0.348)	0.000	0.000	0.000	0.000	(0.540)
(9)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.347)	0.000	0.000	0.000	0.000	(0.497)
(10)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.024)	(0.348)	0.000	0.000	0.000	0.000	(0.480)
(11)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.028)	(0.348)	0.000	0.000	0.000	0.000	(0.484)
(12)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.031)	(0.348)	0.000	0.000	0.000	0.000	(0.487)
(13)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.026)	(0.348)	0.000	0.000	0.000	0.000	(0.482)
(14)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.034)	(0.348)	0.000	0.000	0.000	0.000	(0.490)
(15)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.022)	(0.348)	0.000	0.000	0.000	0.000	(0.478)
(16)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.042)	(0.348)	0.000	0.000	0.000	0.000	(0.498)
(17)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.188)	(0.395)	0.000	0.000	0.000	0.000	(0.691)
(18)	**2003**	**(1.299)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.567)**	**(4.213)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.079)**
(19)	January	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.041)	(0.348)	0.000	0.000	0.000	0.000	(0.497)
(20)	February	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.494)
(21)	March	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.091)	(0.348)	0.000	0.000	0.000	0.000	(0.547)
(22)	April	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.434)	0.000	0.000	0.000	0.000	(0.586)
(23)	May	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.037)	(0.296)	0.000	0.000	0.000	0.000	(0.441)
(24)	June	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(25)	July	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.048)	(0.348)	0.000	0.000	0.000	0.000	(0.504)
(26)	August	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.039)	(0.348)	0.000	0.000	0.000	0.000	(0.495)
(27)	September	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.043)	(0.348)	0.000	0.000	0.000	0.000	(0.499)
(28)	October	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(29)	November	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(30)	December	(0.108)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.055)	(0.348)	0.000	0.000	0.000	0.000	(0.511)
(31)	**2004**	**(1.298)**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**(0.591)**	**(4.207)**	**0.000**	**0.000**	**0.000**	**0.000**	**(6.095)**
(32)	2005	**(1.297)**	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.663)	(4.171)	0.000	0.000	0.000	0.000	(6.132)
(33)	2006	(0.004)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.387)	(3.476)	0.000	0.000	0.000	0.000	(3.866)
(34)	2007	(0.003)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.003)
(35)	2008	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)
(36)	2009	(0.002)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	(0.002)

Column Notes:
(2)-(16) Actual Divestiture related adjustments.
(11) Includes Narragansett Electric's 22.4% share of operating expense charges.
(17) Sum of columns (2) through (16).

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Newport Electric Corporation CTC Calculation

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO NEWPORT ELECTRIC COMPANY

Schedule 1
Page 1 of 15

YEAR	EST. NEC MWH SALES	SHARE OF FIXED COMPONENT $ IN 000	SHARE OF FIXED COMPONENT CENTS/KWH	SHARE OF VAR. COMPONENT $ IN 000	SHARE OF VAR. COMPONENT CENTS/KWH	SHARE OF TOTAL TERM CHARGE $ IN 000	BASE CONTRACT TERM CHARGE CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	530,586	6,196	1.17	9,721	1.83	15,918	3.00
PRE RVC '99	134,139	1,666	1.24	2,358	1.76	4,025	3.00
POST RVC '99	402,416	4,154	1.03	4,139	1.03	8,293	2.06
2000	544,130	7,963	1.46	3,107	0.57	11,070	2.03
2001	549,613	3,371	0.61	4,411	0.80	7,782	1.42
2002	555,606	3,018	0.54	5,059	0.91	8,077	1.45
2003	563,367	4,395	0.78	4,838	0.86	9,232	1.64
2004	571,358	4,436	0.78	3,106	0.54	7,542	1.32
2005	580,288	3,741	0.64	3,141	0.54	6,882	1.19
2006	589,480	-4	0.00	5,295	0.90	5,291	0.90
2007	596,369	2,670	0.45	3,623	0.61	6,293	1.06
2008	603,135	2,011	0.33	2,431	0.40	4,441	0.74
2009	609,079	2,907	0.48	2,382	0.39	5,289	0.87
2010	616,061	0	0.00	1,085	0.18	1,085	0.18
2011	622,439	0	0.00	376	0.06	376	0.06
2012	627,545	0	0.00	341	0.05	341	0.05
2013	636,621	0	0.00	306	0.05	306	0.05
2014	643,741	0	0.00	297	0.05	297	0.05
2015	649,276	0	0.00	288	0.04	288	0.04
2016	654,269	0	0.00	280	0.04	280	0.04
2017	661,599	0	0.00	235	0.04	235	0.04
2018	667,717	0	0.00	228	0.03	228	0.03
2019	673,767	0	0.00	221	0.03	221	0.03
2020	680,723	0	0.00	188	0.03	188	0.03
2021	687,311	0	0.00	0	0.00	0	0.00
2022	694,002	0	0.00	0	0.00	0	0.00
2023	700,796	0	0.00	0	0.00	0	0.00
2024	707,697	0	0.00	0	0.00	0	0.00
2025	714,705	0	0.00	0	0.00	0	0.00
2026	721,821	0	0.00	0	0.00	0	0.00
2027	757,912	0	0.00	0	0.00	0	0.00
2028	795,808	0	0.00	0	0.00	0	0.00
2029	835,598	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	3,670	2,381	145	**6,196**	0	6,196
PRE RVC '99	862	769	36	**1,666**	0	1,666
POST RVC '99	2,944	2,327	(26)	**5,245**	(1,091)	4,154
2000	3,355	6,071	(36)	**9,390**	(1,427)	7,963
2001	2,948	1,870	(35)	**4,783**	(1,412)	3,371
2002	2,804	1,659	(33)	**4,430**	(1,412)	3,018
2003	2,605	3,233	(32)	**5,807**	(1,412)	4,395
2004	2,329	3,549	(30)	**5,848**	(1,412)	4,436
2005	2,057	3,125	(29)	**5,154**	(1,412)	3,741
2006	881	554	(27)	**1,408**	(1,412)	-4
2007	721	3,387	(26)	**4,082**	(1,412)	2,670
2008	461	2,986	(24)	**3,423**	(1,412)	2,011
2009	170	4,172	(23)	**4,319**	(1,412)	2,907

COLUMN NOTES:
EACH COLUMN REPRESENTS 11.85% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
NEWPORT ELECTRIC COMPANY SHARE (11.85%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS POWER TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	949	17,296	8,161	9,134	0	(575)	0	(575)	56	157	0	0	0	0	9,721	0	**9,721**
PRE RVC '99	219	4,328	2,108	2,220	0	(132)	0	(132)	13	38	0	0	0	0	2,358	0	**2,358**
POST RVC '99	843	4,395	0	4,395	0	(257)	0	(257)	(80)	43	0	0	0	0	4,944	(805) **(a)**	**4,139**
2000	1,001	5,984	0	5,984	0	(97)	0	(97)	(61)	23	0	0	0	0	6,851	(3,744) **(b)**	**3,107**
2001	866	6,404	0	6,404	0	0	0	0	(38)	23	0	0	0	0	7,254	(2,844)	**4,411**
2002	773	6,429	0	6,429	0	0	0	0	0	7	0	0	0	0	7,208	(2,149)	**5,059**
2003	708	4,749	0	4,749	0	0	0	0	0	0	0	0	0	0	5,457	(619)	**4,838**
2004	687	4,415	0	4,415	0	0	0	0	0	0	0	0	0	0	5,102	(1,996)	**3,106**
2005	670	4,834	0	4,834	0	0	0	0	0	0	0	0	0	0	5,504	(2,364)	**3,141**
2006	1,020	4,219	0	4,219	0	0	0	0	0	0	0	0	0	0	5,239	56	**5,295**
2007	936	2,687	0	2,687	0	0	0	0	0	0	0	0	0	0	3,623	0	**3,623**
2008	811	1,620	0	1,620	0	0	0	0	0	0	0	0	0	0	2,431	0	**2,431**
2009	723	1,659	0	1,659	0	0	0	0	0	0	0	0	0	0	2,382	0	**2,382**
2010	699	385	0	385	0	0	0	0	0	0	0	0	0	0	1,085	0	**1,085**
2011	0	376	0	376	0	0	0	0	0	0	0	0	0	0	376	0	**376**
2012	0	341	0	341	0	0	0	0	0	0	0	0	0	0	341	0	**341**
2013	0	306	0	306	0	0	0	0	0	0	0	0	0	0	306	0	**306**
2014	0	297	0	297	0	0	0	0	0	0	0	0	0	0	297	0	**297**
2015	0	288	0	288	0	0	0	0	0	0	0	0	0	0	288	0	**288**
2016	0	280	0	280	0	0	0	0	0	0	0	0	0	0	280	0	**280**
2017	0	235	0	235	0	0	0	0	0	0	0	0	0	0	235	0	**235**
2018	0	228	0	228	0	0	0	0	0	0	0	0	0	0	228	0	**228**
2019	0	221	0	221	0	0	0	0	0	0	0	0	0	0	221	0	**221**
2020	0	188	0	188	0	0	0	0	0	0	0	0	0	0	188	0	**188**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 11.85% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)		$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)		UNRECOVERED BALANCE @ APRIL 1, 1999
FOSSIL FUEL UNITS										
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032		23,716	2,158		22,135
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041		35,207	2,917		32,859
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030		1,806	112		1,686
NEWPORT DIESELS	JAMESTOWN/	1961	DIESEL	8.8	1,803		1,499	152		1,399
	PORTSMOUTH, RI/	1978	DIESEL	8.3						
	YARMOUTH, ME	1978	OIL	4.1						
NUCLEAR UNITS										
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705		160,949	4,878		150,217
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749		128,279	4,735		119,726
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786	(a)	3,092	347		2,886
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439	(a)	6,105	667		5,698
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604		604			564
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860		6,449		(b)	6,019
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610		2,610			2,436
			TOTAL	542.6	401,659		370,316	15,966		345,624

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF DECEMBER 31, 1995	BALANCE AS OF DECEMBER 31, 1997	APPLICABLE AMORTIZATION FOR 1996 AND BEYOND		BASIS FOR DEFERRAL	UNRECOVERED BALANCE @ APRIL 1, 1999
	(1)	(2)	(3)		(4)	
FAS 109 - ASSET	39,916	37,466	1,225		FERC RATEMAKING POLICY	34,968
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)		FERC RATEMAKING POLICY	(1,258)
- ITC GROSS-UP	(8,119)	(7,369)	(375)			(6,878)
FAS 106 DEFERRAL	1,313	538	387	(a)	FERC RATEMAKING POLICY	502
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)		FAS 87	(387)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607		FERC RATEMAKING POLICY	9,954
UNAMORTIZED ITC	(12,523)	(11,367)	(578)		FERC RATEMAKING POLICY	(10,609)
DREDGING	424	173	125	(b)	FERC RATEMAKING POLICY	161
TOTAL REG. ASSETS	27,941	28,343	(202)			26,453

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95	9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)	534	
DISCOUNT RATE	7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
PRE RVC '99	167	133	300	7,187
POST RVC '99	(124)	(93)	(218)	(1,866) (a)
2000	(187)	(120)	(306)	(1,680)
2001	(187)	(107)	(294)	(1,493)
2002	(187)	(94)	(281)	(1,306)
2003	(187)	(82)	(269)	(1,120)
2004	(187)	(69)	(256)	(933)
2005	(187)	(57)	(243)	(747)
2006	(187)	(44)	(231)	(560)
2007	(187)	(31)	(218)	(373)
2008	(187)	(19)	(206)	(187)
2009	(187)	(6)	(193)	0

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UP
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,731)	(6,161)	(2,480)	(140)	(1,976)	(17,487)
POST RVC '99	(352)	(322)	0	0	0	(674)
2000	0	(511)	0	0	0	(511)
2001	0	(319)	0	0	0	(319)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	**0**	**1,195**	**68**	**3,944**
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,522
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	**10,660**	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	30,970	20,094	1,226	**52,290**	0	52,290
PRE RVC '99	7,275	6,487	300	**14,063**	0	14,063
POST RVC '99	24,846	19,637	(218)	**44,266**	(9,209)	35,057
2000	28,310	51,236	(306)	**79,239**	(12,039)	67,200
2001	24,877	15,781	(294)	**40,364**	(11,916)	28,448
2002	23,665	14,003	(281)	**37,387**	(11,916)	25,471
2003	21,983	27,285	(269)	**49,000**	(11,916)	37,084
2004	19,653	29,954	(256)	**49,350**	(11,916)	37,435
2005	**17,359**	**26,374**	(243)	**43,489**	(11,916)	31,574
2006	7,437	4,674	(231)	**11,880**	(11,916)	-36
2007	6,083	28,586	(218)	**34,451**	(11,916)	22,535
2008	3,893	25,195	(206)	**28,883**	(11,916)	16,967
2009	1,434	35,208	(193)	**36,449**	(11,916)	24,533

COLUMN NOTES:
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.1185 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17) /.1185
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENTS
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	351,651	26,914	378,565	64,768	0	64,768	313,797	123,087
PRE RVC '99	345,624	26,453	372,077	63,658	0	63,658	308,419	120,977
POST RVC '99	322,555 (a)	42,062 (a)	364,617 (a)	57,468	0	57,468	307,149	120,479
2000	277,229	36,151	313,381	49,392	0	49,392	263,988	103,549
2001	263,269	34,331	297,600	46,905	0	46,905	250,695	98,335
2002	250,881	32,715	283,596	44,698	0	44,698	238,898	93,708
2003	226,743	29,568	256,311	40,398	0	40,398	215,914	84,692
2004	200,245	26,112	226,358	35,676	0	35,676	190,681	74,795
2005	82,858	10,805	93,663	14,762	0	14,762	78,900	30,949
2006	78,723	10,266	88,989	14,026	0	14,026	74,963	29,404
2007	53,435	6,968	60,403	9,520	0	9,520	50,883	19,959
2008	31,146	4,062	35,208	5,549	0	5,549	29,659	11,634
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	378,565	123,087	255,478	262,258	29,735	1,235	30,970
PRE RVC '99	372,077	120,977	251,100	246,722 (a)	6,993	282	7,275
POST RVC '99	364,617	120,479	244,137	253,044 (b)	24,846	0	24,846
2000	313,381	103,549	209,831	226,984	28,310	0	28,310
2001	297,600	98,335	199,265	204,548	24,877	0	24,877
2002	283,596	93,708	189,889	194,577	23,665	0	23,665
2003	256,311	84,692	171,619	180,754	21,983	0	21,983
2004	226,358	74,795	151,563	161,591	19,653	0	19,653
2005	93,663	30,949	62,714	107,138	**17,359**	0	17,359
2006	88,989	29,404	59,585	61,149	7,437	0	7,437
2007	60,403	19,959	40,444	50,014	6,083	0	6,083
2008	35,208	11,634	23,574	32,009	3,893	0	3,893
2009	0	0	0	11,787	1,434	0	1,434

EECo 12/31/95 **CAPITAL STRUCTURE**			PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000		ATWACC	BTWACC
COM PRE RVC	48.45%	9.20% (c)	4.46%	7.33%			57.35%	11.00% (c)	6.31%	10.38%
COM POST RVC		11.40%			5.52%	9.09%				
PFD	5.95%	9.83%	0.58%	0.96%	0.58%	0.96%	0.21%	6.00%	0.01%	0.02%
LTD	45.60%	6.67%	3.04%	3.04%	3.04%	3.04%	42.44%	4.15%	1.76%	1.76%
	100.00%		8.08%	11.338%	9.15%	13.092%	100.00%		8.08%	12.162%
TAX RATE				39.225%		39.225%				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND ASSOCIATED DEF TAXES OF ($17,792) AND $6,979 FOR ITC LIAB AND, $5,797 AND $1,456 FOR MAINE YANKEE
(c) PER NEP RI FILING.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,522	17,790	18,732	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,902**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(674)	364	0	0	0	0	**41,719**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(511)	193	0	0	0	0	**57,814**
2001	7,304	54,041	0	54,041	0	0	0	0	(319)	193	0	0	0	0	**61,219**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	NEWPORT REVENUE EXCESS/ (SHORTFALL) (6)
2000	544,130	585,428	41,298	2.03	818
2001	549,613	593,463	(43,850)	1.42	645
2002	555,606	592,935	(37,329)	1.45	512
Jan-2003	46,947	58,604	(11,656)	1.64	132
Feb-2003	46,947	54,669	(7,722)	1.64	127
Mar-2003	46,947	52,512	(5,565)	1.64	92
Apr-2003	46,947	47,852	(905)	1.64	15
May-2003	46,947	43,838	3,109	1.64	(50)
Jun-2003	46,947	46,167	780	1.64	(12)
Jul-2003	46,947	52,304	(5,356)	1.64	88
Aug-2003	46,947	58,983	(12,035)	1.64	198
Sep-2003	46,947	58,037	(11,089)	1.64	182
Oct-2003	46,947	50,419	(3,472)	1.64	58
Nov-2003	46,947	45,451	1,497	1.64	(24)
Dec-2003	46,947	53,263	(6,315)	1.64	104
2003	563,367	622,097	(58,730)	1.64	910
Jan-2004	47,613	58,036	(10,423)	1.32	237
Feb-2004	47,613	55,559	(7,946)	1.32	104
Mar-2004	47,613	52,786	(5,172)	1.32	67
Apr-2004	47,613	49,067	(1,454)	1.32	18
May-2004	47,613	44,477	3,137	1.32	(42)
Jun-2004	47,613	46,527	1,087	1.32	(15)
Jul-2004	47,613	53,639	(6,026)	1.32	79
Aug-2004	47,613	56,318	(8,705)	1.32	114
Sep-2004	47,613	58,037	(10,424)	1.32	137
Oct-2004	47,613	**47,613**	0	1.32	(0)
Nov-2004	47,613	**47,613**	0	1.32	(0)
Dec-2004	47,613	**47,613**	0	1.32	(0)
2004	571,358	617,285	(45,927)	1.32	698
Jan-2005	48,357	48,357	0	1.19	0
Feb-2005	48,357	48,357	0	1.19	0
Mar-2005	48,357	48,357	0	1.19	0
Apr-2005	48,357	48,357	0	1.19	0
May-2005	48,357	48,357	0	1.19	0
Jun-2005	48,357	48,357	0	1.19	0
Jul-2005	48,357	48,357	0	1.19	0
Aug-2005	48,357	48,357	0	1.19	0
Sep-2005	48,357	48,357	0	1.19	0
Oct-2005	48,357	48,357	0	1.19	0
Nov-2005	48,357	48,357	0	1.19	0
Dec-2005	48,357	48,357	0	1.19	0
2005	580,288	580,288	0	1.19	0
2006	589,480	589,480	0	0.90	0
2007	596,369	596,369	0	1.06	0
2008	603,135	603,135	0	0.74	0
2009	609,079	609,079	0	0.87	0
2010	616,061	616,061	0	0.18	0
2011	622,439	622,439	0	0.06	0
2012	627,545	627,545	0	0.05	0
2013	636,621	636,621	0	0.05	0
2014	643,741	643,741	0	0.05	0
2015	649,276	649,276	0	0.04	0
2016	654,269	654,269	0	0.04	0
2017	661,599	661,599	0	0.04	0
2018	667,717	667,717	0	0.03	0
2019	673,767	673,767	0	0.03	0
2020	680,723	680,723	0	0.03	0
2021	687,311	687,311	0	0.00	0
2022	694,002	694,002	0	0.00	0
2023	700,796	700,796	0	0.00	0
2024	707,697	707,697	0	0.00	0
2025	714,705	714,705	0	0.00	0
2026	721,821	721,821	0	0.00	0
2027	757,912	757,912	0	0.00	0
2028	795,808	795,808	0	0.00	0
2029	835,598	835,598	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S DELIVERED THROUGH SEP 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFT
(4) COLUMN (3)- COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,814	5,971	0	0	43,286	(39)	(29)	(583)	142	0	0	(177)	(3,388)	45,240
2001	61,219	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,508)	(64)	48,385
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,409)	(55)	59,122
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,499
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(0)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,677
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(6)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,057
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,996) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,068)	0	36,341
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(10)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(3)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(5)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,295
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(118)	0	39,936
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) Represents Montaup's share of Millstone 3 employee severance costs.
(b) Includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) Includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL THROUGH SEP 2004, RE-ESTIMATED OCT - DEC 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL THROUGH SEP 2004. ASSUMED TO EQUAL THE ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK.
AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT
NEWPORT ELECTRIC COMPANY
($000)

Schedule 2
Page 1c

YEAR (1)	DELTA VARIABLE COMP. (21)	NEWPORT SHARE DELTA VAR. COMP. (22)	NEWPORT ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,574)	(1,490)	2,308
2001	(12,834)	(1,521)	2,166
2002	(1,709)	(202)	714
Jan-2003	(2,061)	(244)	376
Feb-2003	(818)	(97)	224
Mar-2003	(635)	(75)	167
Apr-2003	661	78	(63)
May-2003	422	50	(100)
Jun-2003	(1,160)	(138)	125
Jul-2003	321	38	50
Aug-2003	304	36	162
Sep-2003	(171)	(20)	203
Oct-2003	219	26	32
Nov-2003	(63)	(7)	(16)
Dec-2003	(6,724)	(797)	901
2003	(9,706)	(1,150)	2,060
Jan-2004	(1,617)	(192)	429
Feb-2004	(93)	(11)	115
Mar-2004	147	17	50
Apr-2004	(530)	(63)	81
May-2004	(100)	(12)	(31)
Jun-2004	(279)	(33)	18
Jul-2004	(274)	(32)	111
Aug-2004	(293)	(35)	149
Sep-2004	(231)	(27)	164
Oct-2004	51	6	(6)
Nov-2004	51	6	(6)
Dec-2004	51	6	(6)
2004	(3,117)	(369)	1,067
Jan-2005	369	44	(44)
Feb-2005	369	44	(44)
Mar-2005	369	44	(44)
Apr-2005	369	44	(44)
May-2005	369	44	(44)
Jun-2005	369	44	(44)
Jul-2005	369	44	(44)
Aug-2005	369	44	(44)
Sep-2005	369	44	(44)
Oct-2005	369	44	(44)
Nov-2005	369	44	(44)
Dec-2005	(4,066)	(482)	482
2005	(11)	(1)	1
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 11.85%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY SHARE

Schedule 2
Page 2 of 2

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			NEWPORT ELECTRIC COMPANY ACCOUNT							
YEAR (1)	DEFERRAL OF CONTRACT TERMINATION DATE (2)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (3)	BUYOUT SAVINGS (4)	VARIABLE RECONCIL. ADJUSTMENT (5)	DEFERRAL OF CONTRACT TERM. DATE (6)	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE (7)	BUYOUT SAVINGS (8)	ANNUAL SHORTFALL/ (EXCESS) (9)	ANNUAL PRE-TAX RETURN ON BALANCE (10)	COLLECTION OF PRIOR YR BAL. INCL. INTEREST (11)	END OF YR. ACCOUNT BALANCE (12)
1999	0	0	0	0	0	0	0	0	0	0	(3,744)
2000	0	0	0	(2,308)	0	0	0	(2,308)	(413)	(3,744)	(2,720)
2001	0	0	0	(2,166)	0	0	0	(2,166)	(348)	(2,844)	(2,391)
2002	0	0	0	(714)	0	0	0	(714)	(192)	(2,149)	(1,148)
Jan-2003	0	0	0	(376)	0	0	0	(376)	(13)	(52)	(1,485)
Feb-2003	0	0	0	(224)	0	0	0	(224)	(16)	(52)	(1,674)
Mar-2003	0	0	0	(167)	0	0	0	(167)	(18)	(52)	(1,807)
Apr-2003	0	0	0	63	0	0	0	63	(18)	(52)	(1,710)
May-2003	0	0	0	100	0	0	0	100	(17)	(52)	(1,575)
Jun-2003	0	0	0	(125)	0	0	0	(125)	(16)	(52)	(1,665)
Jul-2003	0	0	0	(50)	0	0	0	(50)	(17)	(52)	(1,680)
Aug-2003	0	0	0	(162)	0	0	0	(162)	(18)	(52)	(1,808)
Sep-2003	0	0	0	(203)	0	0	0	(203)	(19)	(52)	(1,979)
Oct-2003	0	0	0	(32)	0	0	0	(32)	(20)	(52)	(1,978)
Nov-2003	0	0	0	16	0	0	0	16	(20)	(52)	(1,930)
Dec-2003	0	0	0	(901)	0	0	0	(901)	(24)	(52)	(2,803)
2003	0	0	0	(2,060)	0	0	0	(2,060)	(214)	(619)	(2,803)
Jan-2004	0	0	0	(429)	0	0	0	(429)	(30)	(166)	(3,096)
Feb-2004	0	0	0	(115)	0	0	0	(115)	(31)	(166)	(3,075)
Mar-2004	0	0	0	(50)	0	0	0	(50)	(31)	(166)	(2,989)
Apr-2004	0	0	0	(81)	0	0	0	(81)	(30)	(166)	(2,934)
May-2004	0	0	0	31	0	0	0	31	(29)	(166)	(2,766)
Jun-2004	0	0	0	(18)	0	0	0	(18)	(27)	(166)	(2,644)
Jul-2004	0	0	0	(111)	0	0	0	(111)	(27)	(166)	(2,616)
Aug-2004	0	0	0	(149)	0	0	0	(149)	(26)	(166)	(2,624)
Sep-2004	0	0	0	(164)	0	0	0	(164)	(27)	(166)	(2,649)
Oct-2004	0	0	0	6	0	0	0	6	(26)	(166)	(2,502)
Nov-2004	0	0	0	6	0	0	0	6	(24)	(166)	(2,354)
Dec-2004	0	0	0	6	0	0	0	6	(23)	(166)	(2,205)
2004	0	0	0	(1,067)	0	0	0	(1,067)	(330)	(1,996)	(2,205)
Jan-2005	0	0	0	44	0	0	0	44	(21)	(197)	(1,985)
Feb-2005	0	0	0	44	0	0	0	44	(19)	(197)	(1,764)
Mar-2005	0	0	0	44	0	0	0	44	(17)	(197)	(1,540)
Apr-2005	0	0	0	44	0	0	0	44	(14)	(197)	(1,313)
May-2005	0	0	0	44	0	0	0	44	(12)	(197)	(1,085)
Jun-2005	0	0	0	44	0	0	0	44	(10)	(197)	(854)
Jul-2005	0	0	0	44	0	0	0	44	(7)	(197)	(621)
Aug-2005	0	0	0	44	0	0	0	44	(5)	(197)	(385)
Sep-2005	0	0	0	44	0	0	0	44	(3)	(197)	(147)
Oct-2005	0	0	0	44	0	0	0	44	(0)	(197)	93
Nov-2005	0	0	0	44	0	0	0	44	2	(197)	336
Dec-2005	0	0	0	(482)	0	0	0	(482)	2	(197)	53
2005	0	0	0	(1)	0	0	0	(1)	(104)	(2,364)	53
2006	0	0	0	0	0	0	0	0	3	56	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	(0)
2010	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	(0)
2014	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	(0)
2018	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	(0)
2022	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
										0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(4) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(6) COLUMN (2) x 11.85%
(7) COLUMN (3) x 11.85%
(8) COLUMN (4) x 11.85%
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 X RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

Revised Schedules 1 & 2 to Appendix 1 of NEP / Narragansett Electric Company T1 Service Agreement

Blackstone Valley Electric Company CTC Calculation

Print

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES TO BLACKSTONE VALLEY ELECTRIC

Schedule 1
Page 1 of 15

YEAR	EST. BVE MWH SALES	SHARE OF FIXED COMPONENT $ IN 000	SHARE OF FIXED COMPONENT CENTS/KWH	SHARE OF VAR. COMPONENT $ IN 000	SHARE OF VAR. COMPONENT CENTS/KWH	SHARE OF TOTAL TERM CHARGE $ IN 000	BASE CONTRACT TERM CHARGE CENTS/KWH
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
PRE RVC '99	327,284	4,021	1.23	5,797	1.77	9,819	3.00
POST RVC '99	981,853	9,866	1.00	10,198	1.04	20,064	2.04
2000	1,329,905	17,717	1.33	9,065	0.68	26,782	2.01
2001	1,346,024	8,079	0.60	12,689	0.94	20,767	1.54
2002	1,360,074	7,340	0.54	13,936	1.02	21,276	1.56
2003	1,377,851	10,865	0.79	13,392	0.97	24,257	1.76
2004	1,399,848	11,204	0.80	10,218	0.73	21,422	1.53
2005	1,423,866	9,647	0.68	10,272	0.72	19,919	1.40
2006	1,452,574	395	0.03	13,020	0.90	13,415	0.92
2007	1,471,219	8,550	0.58	8,906	0.61	17,456	1.19
2008	1,493,432	5,586	0.37	5,976	0.40	11,562	0.77
2009	1,512,696	7,986	0.53	5,856	0.39	13,842	0.92
2010	1,534,838	0	0.00	2,666	0.17	2,666	0.17
2011	1,550,396	0	0.00	923	0.06	923	0.06
2012	1,566,958	0	0.00	837	0.05	837	0.05
2013	1,597,666	0	0.00	752	0.05	752	0.05
2014	1,624,096	0	0.00	730	0.04	730	0.04
2015	1,644,785	0	0.00	708	0.04	708	0.04
2016	1,671,116	0	0.00	687	0.04	687	0.04
2017	1,693,977	0	0.00	579	0.03	579	0.03
2018	1,713,946	0	0.00	561	0.03	561	0.03
2019	1,739,097	0	0.00	544	0.03	544	0.03
2020	1,762,428	0	0.00	461	0.03	461	0.03
2021	1,787,024	0	0.00	0	0.00	0	0.00
2022	1,811,988	0	0.00	0	0.00	0	0.00
2023	1,837,328	0	0.00	0	0.00	0	0.00
2024	1,863,048	0	0.00	0	0.00	0	0.00
2025	1,889,155	0	0.00	0	0.00	0	0.00
2026	1,915,656	0	0.00	0	0.00	0	0.00
2027	2,011,439	0	0.00	0	0.00	0	0.00
2028	2,112,011	0	0.00	0	0.00	0	0.00
2029	2,217,611	0	0.00	0	0.00	0	0.00

COLUMN NOTES:
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST.
(3) SCHEDULE 1, PG. 2, COLUMN (7).
(4) COLUMN (3) / COLUMN (2).
(5) SEE SCHEDULE 1, PG. 3, COLUMN (18).
(6) COLUMN (5) / COLUMN (2).
(7) COLUMN (3) + COLUMN (5).
(8) COLUMN (7) / COLUMN (2).

SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	9,035	5,507	357	**14,900**	0	14,900
PRE RVC '99	2,129	1,806	86	**4,021**	0	4,021
POST RVC '99	7,276	5,366	(63)	**12,578**	(2,712)	9,866
2000	8,395	12,957	(89)	**21,263**	(3,546)	17,717
2001	7,489	4,186	(86)	**11,589**	(3,510)	8,079
2002	7,165	3,767	(82)	**10,850**	(3,510)	7,340
2003	6,696	7,758	(78)	**14,375**	(3,510)	10,865
2004	6,023	8,766	(75)	**14,714**	(3,510)	11,204
2005	5,345	7,883	(71)	**13,157**	(3,510)	9,647
2006	2,439	1,533	(67)	**3,905**	(3,510)	395
2007	1,963	10,160	(64)	**12,060**	(3,510)	8,550
2008	1,227	7,930	(60)	**9,097**	(3,510)	5,586
2009	452	11,100	(56)	**11,496**	(3,510)	7,986

COLUMN NOTES:
EACH COLUMN REPRESENTS 29.13% OF THE SAME COLUMN NUMBER ON PG. 12.

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
BLACKSTONE VALLEY ELECTRIC COMPANY SHARE (29.13%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS TOTAL OBLIGATION (3)	POWER CONTRACTS ASSUMED MARKET VALUE (4)	POWER CONTRACTS NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS POWER TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT. COSTS (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PMTS IN LIEU OF PROP. TAXES (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	DAMAGES, COSTS, OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REMAIN. AFTER MKT. VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	RECONCIL. ACCOUNT (17)	**TOTAL VARIABLE COMPONENT INCLUDING INCENTIVE (18)**
1998	2,334	42,517	20,062	22,454	0	(1,414)	0	(1,414)	138	385	0	0	0	0	23,897	0	**23,897**
PRE RVC '99	538	10,639	5,182	5,456	0	(324)	0	(324)	33	94	0	0	0	0	5,797	0	**5,797**
POST RVC '99	2,073	10,803	0	10,803	0	(633)	0	(633)	(188)	106	0	0	0	0	12,161	(1,964) **(a)**	**10,198**
2000	2,460	14,711	0	14,711	0	(237)	0	(237)	(144)	56	0	0	0	0	16,846	(7,781) **(b)**	**9,065**
2001	2,128	15,742	0	15,742	0	0	0	0	(90)	56	0	0	0	0	17,836	(5,147)	**12,689**
2002	1,901	15,803	0	15,803	0	0	0	0	0	16	0	0	0	0	17,720	(3,784)	**13,936**
2003	1,739	11,674	0	11,674	0	0	0	0	0	0	0	0	0	0	13,413	(21)	**13,392**
2004	1,688	10,853	0	10,853	0	0	0	0	0	0	0	0	0	0	12,541	(2,324)	**10,218**
2005	1,648	11,883	0	11,883	0	0	0	0	0	0	0	0	0	0	13,530	(3,258)	**10,272**
2006	2,507	10,372	0	10,372	0	0	0	0	0	0	0	0	0	0	12,880	140	**13,020**
2007	2,300	6,606	0	6,606	0	0	0	0	0	0	0	0	0	0	8,906	0	**8,906**
2008	1,993	3,983	0	3,983	0	0	0	0	0	0	0	0	0	0	5,976	0	**5,976**
2009	1,778	4,078	0	4,078	0	0	0	0	0	0	0	0	0	0	5,856	0	**5,856**
2010	1,719	947	0	947	0	0	0	0	0	0	0	0	0	0	2,666	0	**2,666**
2011	0	923	0	923	0	0	0	0	0	0	0	0	0	0	923	0	**923**
2012	0	837	0	837	0	0	0	0	0	0	0	0	0	0	837	0	**837**
2013	0	752	0	752	0	0	0	0	0	0	0	0	0	0	752	0	**752**
2014	0	730	0	730	0	0	0	0	0	0	0	0	0	0	730	0	**730**
2015	0	708	0	708	0	0	0	0	0	0	0	0	0	0	708	0	**708**
2016	0	687	0	687	0	0	0	0	0	0	0	0	0	0	687	0	**687**
2017	0	579	0	579	0	0	0	0	0	0	0	0	0	0	579	0	**579**
2018	0	561	0	561	0	0	0	0	0	0	0	0	0	0	561	0	**561**
2019	0	544	0	544	0	0	0	0	0	0	0	0	0	0	544	0	**544**
2020	0	461	0	461	0	0	0	0	0	0	0	0	0	0	461	0	**461**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**(0)**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

COLUMN NOTES:
COLUMN (2) THROUGH (10) REPRESENT 29.13% OF THE SAME COLUMN NUMBER ON PG. 15.
(17) SEE SCHEDULE 2, PG. 2, COLUMN (11).
(18) COLUMN (16) + COLUMN (17).

(a) Schedule 1, page 1, column (2), POST RVC 99 MWH SALES times $0.002
(b) Return of the Reconciliation Account balance at 12/31/99.

MONTAUP ELECTRIC COMPANY
NET CAPABILITY & UNRECOVERED COSTS
AS OF DECEMBER 31, 1995

SOURCE (1)	LOCATION (2)	YEAR(S) PLACED IN SERVICE (3)	ENERGY SOURCE (4)	NET CAPABILITY MW (5)	$ IN 000 1995 (6)	$ IN 000 1997 (7)	APPLICABLE ANNUAL DEPRECIATION FOR 1996 AND BEYOND (8)	UNRECOVERED BALANCE @ APRIL 1, 1999
FOSSIL FUEL UNITS								
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153.2	28,032	23,716	2,158	22,222
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917	32,990
WYMAN 4	YARMOUTH, ME	1978	OIL	12.2	2,030	1,806	112	1,692
NEWPORT DIESELS	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8.8 8.3 4.1	1,803	1,499	152	1,405
NUCLEAR UNITS								
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878	150,813
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45.9	137,749	128,279	4,735	120,200
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12.0	3,786 (a)	3,092	347	2,897
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439 (a)	6,105	667	5,721
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604		566
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860	6,449	(b)	6,043
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610		2,446
			TOTAL	542.6	401,659	370,316	15,966	346,994

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING MATERIALS AND SUPPLIES.
(b) PER M-14 FERC SETTLEMENT AGREEMENT, SOMERSET UNIT 5 IS EXCLUDED FROM PLANT IN SERVICE BUT IS ALLOWED A RETURN THROUGH 11/1/97. (321k IN 1996 AND 268k IN 1997).

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

	BALANCE AS OF		APPLICABLE AMORTIZATION			
	DECEMBER 31, 1995	DECEMBER 31, 1997	FOR 1996 AND BEYOND		BASIS FOR DEFERRAL	UNRECOVERED BALANCE @ APRIL 1, 1999
	(1)	(2)	(3)		(4)	
FAS 109 - ASSET	39,916	37,466	1,225		FERC RATEMAKING POLICY	35,106
- OTHER LIABILITY	(6,464)	(1,348)	(2,558)		FERC RATEMAKING POLICY	(1,263)
- ITC GROSS-UP	(8,119)	(7,369)	(375)			(6,905)
FAS 106 DEFERRAL	1,313	538	387	(a)	FERC RATEMAKING POLICY	504
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)		FAS 87	(389)
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607		FERC RATEMAKING POLICY	9,993
UNAMORTIZED ITC	(12,523)	(11,367)	(578)		FERC RATEMAKING POLICY	(10,651)
DREDGING	424	173	125	(b)	FERC RATEMAKING POLICY	162
TOTAL REG. ASSETS	27,941	28,343	(202)			26,558

(a) REMAINING AMORTIZATION SCHEDULE: 387 IN 1998, 151 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

MONTAUP ELECTRIC COMPANY
FAS 106 TRANSITION OBLIGATION REGULATORY ASSET
$ IN 000

UNRECOVERED BALANCE AS OF 12/31/95			9,091	
AMORTIZATION AMOUNT (1996 & BEYOND)			534	
DISCOUNT RATE			7.25%	6.75%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
PRE RVC '99	167	133	300	7,187
POST RVC '99	(124)	(93)	(218)	(1,866) (a)
2000	(187)	(120)	(306)	(1,680)
2001	(187)	(107)	(294)	(1,493)
2002	(187)	(94)	(281)	(1,306)
2003	(187)	(82)	(269)	(1,120)
2004	(187)	(69)	(256)	(933)
2005	(187)	(57)	(243)	(747)
2006	(187)	(44)	(231)	(560)
2007	(187)	(31)	(218)	(373)
2008	(187)	(19)	(206)	(187)
2009	(187)	(6)	(193)	0

COLUMN NOTES:
(1) 12/31/97 Balance straight lined over 12 years.
(2) (Prior Year Column (4) + Current Year Column (4)) / 2 * 7.25% Pre RVC
then (Prior Year Column (4) + Current Year Column (4)) / 2 * 6.75% Post RVC
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)
(a) FAS 87 & FAS 106 adjustment of ($9,178) netted and amortized over remaining years.

MONTAUP ELECTRIC COMPANY
AMORTIZATION OF ITC AND FAS109 ITC GROSS-UF
$ IN 000

Schedule 1
Page 5b of 15

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	SOMERSET (6)	TOTAL (7)
BAL @ 4/1/99	(6,757)	(6,185)	(2,489)	(140)	(1,984)	(17,556)
						(4,614)
POST RVC '99	(336)	(308)	0	0	0	(644)
2000	0	(494)	0	0	0	(494)
2001	0	(309)	0	0	0	(309)
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

COLUMN NOTES:
(2) through (6) April 1, 1999 Balances amortized through 2009

MONTAUP ELECTRIC COMPANY
OTHER POST-SHUTDOWN NUCLEAR COSTS
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
PRE RVC '99	0	0	0	0	0
POST RVC '99	0	0	0	1,291	1,291
2000	0	0	0	2,075	2,075
2001	0	0	0	2,013	2,013
2002	0	0	0	1,956	1,956
2003	0	0	0	1,890	1,890
2004	0	0	0	1,794	1,794
2005	0	0	0	1,712	1,712
2006	0	0	0	1,622	1,622
2007	0	0	0	1,350	1,350
2008	0	0	0	956	956
2009	0	0	0	0	0
2010	0	0	0	0	0
2011	0	0	0	0	0
2012	0	0	0	0	0
2013	0	0	0	0	0
2014	0	0	0	0	0
2015	0	0	0	0	0
2016	0	0	0	0	0
2017	0	0	0	0	0
2018	0	0	0	0	0
2019	0	0	0	0	0
2020	0	0	0	0	0
2021	0	0	0	0	0
2022	0	0	0	0	0
2023	0	0	0	0	0
2024	0	0	0	0	0
2025	0	0	0	0	0
2026	0	0	0	0	0
2027	0	0	0	0	0
2028	0	0	0	0	0
2029	0	0	0	0	0

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

YEAR (1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	CONNECTICUT YANKEE (4)	VERMONT YANKEE (5)	MAINE YANKEE (6)	YANKEE ATOMIC (7)	TOTAL (8)
1998	602	319	3,868	317	599	2,306	8,011
PRE RVC '99	155	82	776	80	178	577	1,847
POST RVC '99	466	246	2,327	239	819	1,730	5,825
2000	639	0	3,058	407	1,061	1,206	6,371
2001	658	0	2,972	408	1,195	58	5,291
2002	0	0	2,906	409	1,195	60	4,570
2003	0	0	2,823	0	1,195	63	4,081
2004	0	0	2,742	0	1,195	65	4,002
2005	0	0	**2,681**	0	**1,195**	**68**	3,944
2006	0	0	5,627	0	772	586	6,986
2007	0	0	4,993	0	965	586	6,545
2008	0	0	4,185	0	1,114	586	5,885
2009	0	0	4,185	0	1,333	586	6,104
2010	0	0	4,185	0	1,126	590	5,901
2011	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0

Purchase Power Total $000

Schedule 1
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Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro Constellation @4/1/99	HQ	GMP	BSH	OSP @ 9.2% ROE	Total
1998	36,042	25,977	3,932	330	3,562	25,446	27,471	12,513	526	10,662	150	550	(1,206)	145,955
PRE RVC '99	8,928	6,795	994	85	892	6,410	6,751	3,130	132	2,693	0	0	(287)	36,521
POST RVC '99	17,263	0	0	0	0	0	14,980	0	4,843	0	0	0	0	37,086
2000	21,506	0	0	0	0	0	19,980	0	9,015	0	0	0	0	50,501
2001	23,679	0	0	0	0	0	18,504	0	10,610	1,248	0	0	0	54,041
2002	19,429	0	0	0	0	0	18,504	0	12,586	3,731	0	0	0	54,250
2003	21,449	0	0	0	0	0	10,440	0	4,575	3,612	0	0	0	40,076
2004	17,933	0	0	0	0	0	10,440	0	5,376	3,508	0	0	0	37,257
2005	20,638	0	0	0	0	0	10,440	0	6,317	3,397	0	0	0	40,792
2006	14,519	0	0	0	0	0	10,440	0	7,422	3,225	0	0	0	35,606
2007	429	0	0	0	0	0	10,440	0	8,721	3,088	0	0	0	22,678
2008	429	0	0	0	0	0	0	0	10,247	2,997	0	0	0	13,673
2009	429	0	0	0	0	0	0	0	10,660	2,909	0	0	0	13,998
2010	429	0	0	0	0	0	0	0	0	2,823	0	0	0	3,252
2011	429	0	0	0	0	0	0	0	0	2,740	0	0	0	3,169
2012	215	0	0	0	0	0	0	0	0	2,659	0	0	0	2,874
2013	0	0	0	0	0	0	0	0	0	2,581	0	0	0	2,581
2014	0	0	0	0	0	0	0	0	0	2,505	0	0	0	2,505
2015	0	0	0	0	0	0	0	0	0	2,432	0	0	0	2,432
2016	0	0	0	0	0	0	0	0	0	2,360	0	0	0	2,360
2017	0	0	0	0	0	0	0	0	0	1,986	0	0	0	1,986
2018	0	0	0	0	0	0	0	0	0	1,927	0	0	0	1,927
2019	0	0	0	0	0	0	0	0	0	1,869	0	0	0	1,869
2020	0	0	0	0	0	0	0	0	0	1,584	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Purchase Power MWh

Year	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	Total
1998	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	323,962	2,781,183
PRE RVC '99	120,658	147,076	9,245	2,559	4,355	127,136	135,490	48,728	1,363	81,039	677,648
POST RVC '99	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

YEAR END (1)	M-RATE SALES TO MIDDLEBORO (2)	M-RATE SALES TO PASCOAG (3)	CANAL UNIT SALES TO BRAINTREE (4)	TOTAL (5)
1998	2,004	1,295	1,555	4,854
PRE RVC '99	416	309	389	1,113
POST RVC '99	1,247	926	0	2,173
2000	0	815	0	815
2001	0	0	0	0
2002	0	0	0	0
2003	0	0	0	0
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	0	0	0
2021	0	0	0	0
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	0
2028	0	0	0	0
2029	0	0	0	0

TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS
DETAIL BY UNIT
$ IN 000

YEAR (1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YK (6)	VERMONT YK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
PRE RVC '99	73	35	127	23	54	14	324
POST RVC '99	219	104	0	0	0	41	364
2000	0	138	0	0	0	55	193
2001	0	138	0	0	0	55	193
2002	0	0	0	0	0	55	55
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
FIXED COMPONENT
$ IN 000

YEAR (1)	PRE-TAX RETURN ON GENERATION RELATED INV. & REG. ASSETS (2)	AMORT. OF GEN. RELATED INVESTMENT & REG. ASSETS (3)	AMORT. OF FAS 106 TRANSITION OBLIGATION (4)	**BASE TOTAL FIXED COMPONENT (5)**	ADJ. FOR RESIDUAL VALUE CREDIT (6)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (7)
1998	31,016	18,907	1,226	**51,148**	0	51,148
PRE RVC '99	7,309	6,200	300	**13,810**	0	13,810
POST RVC '99	24,977	18,420	(218)	**43,179**	(9,309)	33,870
2000	28,821	44,481	(306)	**72,995**	(12,173)	60,822
2001	25,708	14,369	(294)	**39,783**	(12,050)	27,733
2002	24,596	12,932	(281)	**37,247**	(12,050)	25,197
2003	22,986	26,631	(269)	**49,349**	(12,050)	37,298
2004	20,676	30,093	(256)	**50,513**	(12,050)	38,463
2005	**18,349**	**27,062**	(243)	**45,168**	(12,050)	33,118
2006	8,374	5,263	(231)	**13,407**	(12,050)	1,357
2007	6,740	34,878	(218)	**41,400**	(12,050)	29,350
2008	4,211	27,221	(206)	**31,227**	(12,050)	19,177
2009	1,552	38,106	(193)	**39,464**	(12,050)	27,414

COLUMN NOTES:
(2) See Schedule 1, Pg. 14, Column (8).
(3) Pg. 1, Column (7) /.2913 - Pg. 15, Column (16) - Pg. 12, Column (2)
- Pg. 12, Column (4) - Pg. 12, Column (6) - Pg. 3, Column (17)/.2913.
(4) See Pg. 5a, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based on results of actual market valuation.
(7) Columns (5) + (6).

MONTAUP ELECTRIC COMPANY
SUMMARY OF CONTRACT TERMINATION CHARGES
DEFERRED TAXES ON FIXED COMPONENT
$ IN 000

	BOOK BASIS			TAX BASIS				
YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	BALANCE GENERATION RELATED REG. ASSETS (6)	TOTAL TAX BASIS (7)	EXCESS BOOK OVER TAX (8)	DEFERRED TAXES (9)
1997	370,316	28,343	398,659	68,206	0	68,206	330,453	129,620
1998	352,754	26,999	379,752	64,971	0	64,971	314,781	123,473
PRE RVC '99	346,994	26,558	373,552	63,910	0	63,910	309,641	121,457
POST RVC '99	324,978 (a)	42,378 (a)	367,356 (a)	57,901	0	57,901	309,455	121,384
2000	285,629	37,247	322,876	50,890	0	50,890	271,985	106,686
2001	272,918	35,589	308,507	48,626	0	48,626	259,881	101,938
2002	261,478	34,097	295,575	46,587	0	46,587	248,988	97,666
2003	237,919	31,025	268,944	42,390	0	42,390	226,554	88,866
2004	211,298	27,554	238,851	37,647	0	37,647	201,205	78,922
2005	93,302	12,167	105,468	16,623	0	16,623	88,845	34,849
2006	88,646	11,560	100,205	15,794	0	15,794	84,411	33,110
2007	57,791	7,536	65,327	10,297	0	10,297	55,031	21,586
2008	33,710	4,396	38,106	6,006	0	6,006	32,100	12,591
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 4, COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, PG. 5, COLUMN (2) FOR 1997 BALANCE.
(4) COLUMN (2) + COLUMN (3).
(5) PER TAX RECORDS OF THE COMPANY.
(6) PER TAX RECORDS OF THE COMPANY.
(7) COLUMN (5) + COLUMN (6).
(8) COLUMN (4) - COLUMN (7).
(9) COLUMN (8) x TAX RATE .39225.
(a) EXCLUDES TOTAL ITC LIABILITY AND MAINE YANKEE INVESTMENT WHICH ARE INCLUDED IN THE VARIABLE COMPONENT.
ALSO EXCLUDES UNAMORTIZED PENSION LIABILITY, WHICH IS AMORTIZED WITH FAS106 TRANS. OBLIG.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY
RETURN ON FIXED COMPONENT

YEAR END (1)	BALANCE OF FIXED COMPONENT (2)	DEFERRED TAXES (3)	NET BALANCE (4)	AVG NET BALANCE (5)	SUBTOTAL ANNUAL RETURN ON UNAMORTIZED BALANCE USING BASE ROE (6)	PLUS: RETURN ON UNAMORT. ITC (7)	TOTAL ANNUAL RETURN (8)
1997	398,659	129,620	269,039				
1998	379,752	123,473	256,280	262,659	29,781	1,235	31,016
PRE RVC '99	373,552	121,457	252,095	247,911 (a)	7,027	282	7,309
POST RVC '99	367,356	121,384	245,973	254,372 (b)	24,977	0	24,977
2000	322,876	106,686	216,190	231,081	28,821	0	28,821
2001	308,507	101,938	206,569	211,379	25,708	0	25,708
2002	295,575	97,666	197,910	202,239	24,596	0	24,596
2003	268,944	88,866	180,078	188,994	22,986	0	22,986
2004	238,851	78,922	159,929	170,003	20,676	0	20,676
2005	105,468	34,849	70,619	115,274	**18,349**	0	18,349
2006	100,205	33,110	67,095	68,857	8,374	0	8,374
2007	65,327	21,586	43,741	55,418	6,740	0	6,740
2008	38,106	12,591	25,515	34,628	4,211	0	4,211
2009	0	0	0	12,757	1,552	0	1,552

EECo 12/31/95 **CAPITAL STRUCTURE**			PRE RVC ATWACC	PRE RVC BTWACC	POST RVC ATWACC	POST RVC BTWACC	NEP CAP STRUCTURE BEGINNING 5/1/2000		ATWACC	BTWACC
COM PRE RVC	48.45%	9.20% (c)	4.46%	7.33%	5.52%	9.09%	57.35%	11.00% (c)	6.31%	10.38%
COM POST RVC		11.40%								
PFD PRE RVC	5.95%	9.83%	0.58%	0.96%	0.58%	0.96%	0.21%	6.00%	0.01%	0.02%
LTD PRE RVC	45.60%	6.67%	3.04%	3.04%	3.04%	3.04%	42.44%	4.15%	1.76%	1.76%
	100.00%		8.08%	11.338%	9.15%	13.092%	100.00%		8.08%	12.162%
TAX RATE				39.225%		39.225%				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, PG. 13, COLUMN (4).
(3) SEE SCHEDULE 1, PG. 13, COLUMN (9).
(4) COLUMN (2) - COLUMN (3).
(5) COLUMN (4) PRIOR YEAR+COLUMN (4) CURRENT YEAR /2.
(6) COLUMN (5) x TOTAL RATE OF RETURN.
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF PG. 5, COLUMN (2) * BTWACC).
(8) COLUMN (6) + COLUMN (7).
(a) 1998 AVG NET BALANCE PER ORIGINAL CTC FILING
(b) EXCLUDES 1998 BALANCES AND DEF TAXES OF ($17,847) AND $7,001 FOR ITC LIAB AND, $5,815 AND $1,461 FOR MAINE YANKEE
(c) PER NEP RI FILING.

SUMMARY OF CONTRACT TERMINATION CHARGES
MONTAUP ELECTRIC COMPANY (100%)
VARIABLE COMPONENT

YEAR END (1)	NUCLEAR DECOM AND OTHER POST SHUTDOWN COSTS (2)	POWER CONTRACTS: TOTAL OBLIGATION (3)	POWER CONTRACTS: ASSUMED MARKET VALUE (4)	POWER CONTRACTS: NET: EXCESS OVER MARKET (5)	FUTURE POWER CONTRACT BUYOUTS (6)	CREDIT FOR UNIT SALES CONTRACTS: TOTAL OBLIGATION (7)	CREDIT FOR UNIT SALES CONTRACTS: ASSUMED MARKET VALUE (8)	CREDIT FOR UNIT SALES CONTRACTS: NET: EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANS. TO 4/1/99 ITC AMORT. 4/1/99 (10)	TRANSMISSION IN SUPPORT OF REMOTE GEN. UNITS (11)	PAYMENTS IN LIEU OF PROPERTY TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES, COSTS OR NET RECOVERIES FROM CLAIMS (14)	PBR FOR NUKE UNITS REM. AFTER MKT. VALUATION (15)	**BASE TOTAL VARIABLE COMPONENT (16)**
1998	8,011	145,955	68,872	77,083	0	(4,854)	0	(4,854)	473	1,322	0	0	0	0	**82,035**
PRE RVC '99	1,847	36,521	17,790	18,731	0	(1,113)	0	(1,113)	113	324	0	0	0	0	**19,901**
POST RVC '99	7,116	37,086	0	37,086	0	(2,173)	0	(2,173)	(644)	364	0	0	0	0	**41,749**
2000	8,446	50,501	0	50,501	0	(815)	0	(815)	(494)	193	0	0	0	0	**57,831**
2001	7,304	54,041	0	54,041	0	0	0	0	(309)	193	0	0	0	0	**61,229**
2002	6,526	54,250	0	54,250	0	0	0	0	0	55	0	0	0	0	**60,831**
2003	5,971	40,076	0	40,076	0	0	0	0	0	0	0	0	0	0	**46,047**
2004	5,796	37,257	0	37,257	0	0	0	0	0	0	0	0	0	0	**43,053**
2005	5,656	40,792	0	40,792	0	0	0	0	0	0	0	0	0	0	**46,448**
2006	8,608	35,606	0	35,606	0	0	0	0	0	0	0	0	0	0	**44,214**
2007	7,895	22,678	0	22,678	0	0	0	0	0	0	0	0	0	0	**30,573**
2008	6,841	13,673	0	13,673	0	0	0	0	0	0	0	0	0	0	**20,514**
2009	6,104	13,998	0	13,998	0	0	0	0	0	0	0	0	0	0	**20,102**
2010	5,901	3,252	0	3,252	0	0	0	0	0	0	0	0	0	0	**9,153**
2011	0	3,169	0	3,169	0	0	0	0	0	0	0	0	0	0	**3,169**
2012	0	2,874	0	2,874	0	0	0	0	0	0	0	0	0	0	**2,874**
2013	0	2,581	0	2,581	0	0	0	0	0	0	0	0	0	0	**2,581**
2014	0	2,505	0	2,505	0	0	0	0	0	0	0	0	0	0	**2,505**
2015	0	2,432	0	2,432	0	0	0	0	0	0	0	0	0	0	**2,432**
2016	0	2,360	0	2,360	0	0	0	0	0	0	0	0	0	0	**2,360**
2017	0	1,986	0	1,986	0	0	0	0	0	0	0	0	0	0	**1,986**
2018	0	1,927	0	1,927	0	0	0	0	0	0	0	0	0	0	**1,927**
2019	0	1,869	0	1,869	0	0	0	0	0	0	0	0	0	0	**1,869**
2020	0	1,584	0	1,584	0	0	0	0	0	0	0	0	0	0	**1,584**
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Column Notes:
(2) Schedule 1, Pg. 6, Column (6) + Schedule 1, Pg. 7, Column (8).
(3) Schedule 1, Pg. 8 .
(5) Column (3) - Column (4).
(7) See Schedule 1, Pg. 10, Column (5).
(9) Column (7) - Column (8).
(11) Schedule 1, Pg. 11, Column (8).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

Schedule 2
Page 1a

REVENUE ADJUSTMENTS ($000)

YEAR (1)	ESTIMATED KWH DELIVERED (2)	ACTUAL KWH DELIVERED (3)	DELTA KWH DELIVERED (4)	TRANSITION CHARGE BILLED (5)	BLACKSTONE VALLEY REVENUE EXCESS/ (SHORTFALL) (6)
2000	1,329,905	1,353,414	23,509	2.01	352
2001	1,346,024	1,350,390	(4,366)	1.54	29
2002	1,360,074	1,364,403	(4,328)	1.56	(4)
Jan-2003	114,821	126,572	(11,751)	1.76	71
Feb-2003	114,821	116,475	(1,654)	1.76	29
Mar-2003	114,821	110,251	4,570	1.76	(81)
Apr-2003	114,821	103,044	11,777	1.76	(208)
May-2003	114,821	104,483	10,338	1.76	(183)
Jun-2003	114,821	102,290	12,531	1.76	(221)
Jul-2003	114,821	124,693	(9,872)	1.76	173
Aug-2003	114,821	132,119	(17,298)	1.76	304
Sep-2003	114,821	123,055	(8,234)	1.76	144
Oct-2003	114,821	109,256	5,565	1.76	(99)
Nov-2003	114,821	109,428	5,393	1.76	(95)
Dec-2003	114,821	122,955	(8,135)	1.76	143
2003	1,377,851	1,384,622	(6,771)	1.76	(23)
Jan-2004	116,654	115,422	1,232	1.53	123
Feb-2004	116,654	117,641	(987)	1.53	15
Mar-2004	116,654	116,435	219	1.53	(4)
Apr-2004	116,654	102,351	14,303	1.53	(219)
May-2004	116,654	104,274	12,380	1.53	(190)
Jun-2004	116,654	118,093	(1,439)	1.53	22
Jul-2004	116,654	115,540	1,114	1.53	(17)
Aug-2004	116,654	119,279	(2,625)	1.53	40
Sep-2004	116,654	126,650	(9,996)	1.53	153
Oct-2004	116,654	**116,654**	0	1.53	(0)
Nov-2004	116,654	**116,654**	0	1.53	(0)
Dec-2004	116,654	**116,654**	0	1.53	(0)
2004	1,399,848	1,385,648	14,200	1.53	(79)
Jan-2005	118,656	118,656	0	1.40	0
Feb-2005	118,656	118,656	0	1.40	0
Mar-2005	118,656	118,656	0	1.40	0
Apr-2005	118,656	118,656	0	1.40	0
May-2005	118,656	118,656	0	1.40	0
Jun-2005	118,656	118,656	0	1.40	0
Jul-2005	118,656	118,656	0	1.40	0
Aug-2005	118,656	118,656	0	1.40	0
Sep-2005	118,656	118,656	0	1.40	0
Oct-2005	118,656	118,656	0	1.40	0
Nov-2005	118,656	118,656	0	1.40	0
Dec-2005	118,656	118,656	0	1.40	0
2005	1,423,866	1,423,866	0	1.40	0
2006	1,452,574	1,452,574	0	0.92	0
2007	1,471,219	1,471,219	0	1.19	0
2008	1,493,432	1,493,432	0	0.77	0
2009	1,512,696	1,512,696	0	0.92	0
2010	1,534,838	1,534,838	0	0.17	0
2011	1,550,396	1,550,396	0	0.06	0
2012	1,566,958	1,566,958	0	0.05	0
2013	1,597,666	1,597,666	0	0.05	0
2014	1,624,096	1,624,096	0	0.04	0
2015	1,644,785	1,644,785	0	0.04	0
2016	1,671,116	1,671,116	0	0.04	0
2017	1,693,977	1,693,977	0	0.03	0
2018	1,713,946	1,713,946	0	0.03	0
2019	1,739,097	1,739,097	0	0.03	0
2020	1,762,428	1,762,428	0	0.03	0
2021	1,787,024	1,787,024	0	0.00	0
2022	1,811,988	1,811,988	0	0.00	0
2023	1,837,328	1,837,328	0	0.00	0
2024	1,863,048	1,863,048	0	0.00	0
2025	1,889,155	1,889,155	0	0.00	0
2026	1,915,656	1,915,656	0	0.00	0
2027	2,011,439	2,011,439	0	0.00	0
2028	2,112,011	2,112,011	0	0.00	0
2029	2,217,611	2,217,611	0	0.00	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, PAGE 1, COLUMN (2).
(3) ACTUAL KWH'S THROUGH SEP. 2004. ASSUMED TO EQUAL EST. KWH DELIVERED THEREAFTER.
(4) COLUMN (3) - COLUMN (2).
(5) SEE SCHEDULE 1, PAGE 1, COLUMN (8).
(6) COLUMN (4) X COLUMN (5).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

Schedule 2
Page 1b

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

YEAR (1)	ESTIMATED BASE VARIABLE COMPONENT (7)	ACTUAL NUCLEAR DECOM. COSTS (8)	ACTUAL POWER CONTRACTS OBLIGATIONS (9)	ACTUAL POWER CONTRACTS MARKET VALUE (10)	ACTUAL POWER CONTRACT BUYOUTS (11)	ACTUAL UNIT SALES CONTRACTS REVENUE (12)	ACTUAL UNIT SALES CONTRACTS MARKET VALUE (13)	ACTUAL AMORT OF ITC (14)	TRANSMISSION IN SUPPORT OF REMOTE GENERATING UNITS (15)	ACTUAL PAYMENTS IN LIEU OF PROPERTY TAXES (16)	ACTUAL EMPLOYEE REVENUES SEVERANCE AND RETRAINING COSTS (17)	ACTUAL DAMAGES COSTS, OR NET RECOVERIES FROM CLAIMS (18)	ACTUAL PBR FOR NUKE UNITS REMAINING AFTER MARKET VALUATION (19)	MONTAUP ACTUAL TOTAL VARIABLE COMPONENT (20)
2000	57,831	5,971	0	0	43,286	(39)	(29)	(584)	142	0	0	(182)	(3,390)	45,233
2001	61,229	7,355	0	0	47,725	0	0	(146)	23	0	0	(6,563)	(72)	48,322
2002	60,831	4,462	0	0	55,730	0	0	0	0	0	395	(1,416)	(61)	59,110
Jan-2003	3,837	185	0	0	1,593	0	0	0	0	0	0	(1)	0	1,776
Feb-2003	3,837	502	0	0	2,515	0	0	0	0	0	0	2	0	3,019
Mar-2003	3,837	379	0	0	2,859	0	0	0	0	0	0	(36)	0	3,202
Apr-2003	3,837	357	0	0	4,153	0	0	0	0	0	0	(11)	0	4,498
May-2003	3,837	360	0	0	3,900	0	0	0	0	0	0	(1)	0	4,259
Jun-2003	3,837	576	0	0	2,103	0	0	0	0	0	0	(3)	0	2,676
Jul-2003	3,837	563	0	0	3,600	0	0	0	0	0	0	(5)	0	4,158
Aug-2003	3,837	567	0	0	3,576	0	0	0	0	0	0	(2)	0	4,141
Sep-2003	3,837	572	0	0	3,101	0	0	0	0	0	0	(7)	0	3,666
Oct-2003	3,837	578	0	0	3,478	0	0	0	0	0	0	1	0	4,056
Nov-2003	3,837	596	0	0	3,190	0	0	0	0	0	0	(11)	0	3,774
Dec-2003	3,837	503	0	0	3,607	0	0	0	0	0	0	(6,997) (c)	0	(2,887)
2003	46,047	5,736	0	0	37,673	0	0	0	0	0	0	(7,071)	0	36,338
Jan-2004	3,588	457	0	0	1,524	0	0	0	0	0	0	(11)	0	1,970
Feb-2004	3,588	611	0	0	2,887	0	0	0	0	0	0	(4)	0	3,495
Mar-2004	3,588	555	0	0	3,213	0	0	0	0	0	0	(34)	0	3,734
Apr-2004	3,588	580	0	0	2,484	0	0	0	0	0	0	(6)	0	3,058
May-2004	3,588	576	0	0	2,915	0	0	0	0	0	0	(2)	0	3,488
Jun-2004	3,588	592	0	0	2,722	0	0	0	0	0	0	(6)	0	3,309
Jul-2004	3,588	591	0	0	2,732	0	0	0	0	0	0	(9)	0	3,314
Aug-2004	3,588	595	0	0	2,703	0	0	0	0	0	0	(4)	0	3,294
Sep-2004	3,588	491	0	0	2,871	0	0	0	0	0	0	(6)	0	3,356
Oct-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Nov-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
Dec-2004	3,588	**547**	0	0	**3,105**	0	0	0	0	0	0	**(13)**	0	3,639
2004	43,053	6,690	0	0	33,364	0	0	0	0	0	0	(121)	0	39,933
Jan-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Feb-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Mar-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Apr-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
May-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jun-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Jul-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Aug-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Sep-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Oct-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Nov-2005	3,871	840	0	0	3,399	0	0	0	0	0	0	0	0	4,239
Dec-2005	3,871	840	0	0	3,399	0	0	0	0	**(4,435)** (d)	0	0	0	(196)
2005	46,448	**10,080**	0	0	40,792	0	0	0	0	(4,435)	0	0	0	46,437
2006	44,214	8,608	0	0	35,606	0	0	0	0	0	0	0	0	44,214
2007	30,573	7,895	0	0	22,678	0	0	0	0	0	0	0	0	30,573
2008	20,514	6,841	0	0	13,673	0	0	0	0	0	0	0	0	20,514
2009	20,102	6,104	0	0	13,998	0	0	0	0	0	0	0	0	20,102
2010	9,153	5,901	0	0	3,252	0	0	0	0	0	0	0	0	9,153
2011	3,169	0	0	0	3,169	0	0	0	0	0	0	0	0	3,169
2012	2,874	0	0	0	2,874	0	0	0	0	0	0	0	0	2,874
2013	2,581	0	0	0	2,581	0	0	0	0	0	0	0	0	2,581
2014	2,505	0	0	0	2,505	0	0	0	0	0	0	0	0	2,505
2015	2,432	0	0	0	2,432	0	0	0	0	0	0	0	0	2,432
2016	2,360	0	0	0	2,360	0	0	0	0	0	0	0	0	2,360
2017	1,986	0	0	0	1,986	0	0	0	0	0	0	0	0	1,986
2018	1,927	0	0	0	1,927	0	0	0	0	0	0	0	0	1,927
2019	1,869	0	0	0	1,869	0	0	0	0	0	0	0	0	1,869
2020	1,584	0	0	0	1,584	0	0	0	0	0	0	0	0	1,584
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0

(a) represents Montaup's share of Millstone 3 employee severance costs.
(b) includes Montaup's portion of proceeds from the sale of Vermont Yankee ($1,367,000), offset by operating expenses $46,052.
(c) includes Montaup's proceeds from the sale of land in Somerset, MA.
(d) 2005 interest on USGen settlement proceeds

COLUMN NOTES:
(7) SEE SCHEDULE 1, PAGE 15, COLUMN (16).
(8) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004, RE-ESTIMATED OCT. - DEC. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 15, THEREAFTER.
(11) ACTUAL VARIABLE COMPONENTS THROUGH SEP. 2004. ASSUMED TO EQUAL ESTIMATED VARIABLE COMPONENTS ILLUSTRATED ON SCHEDULE 1, PAGE 16, THEREAFTER.
(18) MONTHLY AMOUNTS INCLUDE AMORTIZATION OF NET PROCEEDS FROM MONTAUP'S SALE OF ITS INTEREST IN SEABROOK. AND, EFFECTIVE AUGUST 2002, INCLUDE ONGOING OVERHEAD AND ADMINISTRATIVE COSTS ASSOCIATED WITH VYNPC.
(19) ACTUAL THROUGH DEC 2003 PER AGREEMENT.
(20) COLUMN (8) + COLUMN (9) - COLUMN (10) + COLUMN (11) + COLUMN (12) - COLUMN (13) + COLUMN (14) + COLUMN (15) + COLUMN (16) + COLUMN (17) + COLUMN (18) + COLUMN (19).

RECONCILIATION ADJUSTMENT
BLACKSTONE VALLEY ELECTRIC
($000)

Schedule 2
Page 1c

YEAR (1)	DELTA VARIABLE COMP. (21)	BLACKSTONE VALLEY SHARE DELTA VAR. COMP. (22)	BLACKSTONE VALLEY ANNUAL RECON. ADJ. EXCESS/ (SHORTFALL) (23)
2000	(12,598)	(3,670)	4,021
2001	(12,907)	(3,760)	3,788
2002	(1,721)	(501)	497
Jan-2003	(2,061)	(600)	671
Feb-2003	(818)	(238)	267
Mar-2003	(636)	(185)	104
Apr-2003	661	193	(400)
May-2003	421	123	(305)
Jun-2003	(1,161)	(338)	117
Jul-2003	321	93	80
Aug-2003	303	88	215
Sep-2003	(171)	(50)	194
Oct-2003	219	64	(162)
Nov-2003	(63)	(18)	(77)
Dec-2003	(6,724)	(1,959)	2,101
2003	(9,709)	(2,828)	2,805
Jan-2004	(1,618)	(471)	594
Feb-2004	(93)	(27)	42
Mar-2004	146	43	(46)
Apr-2004	(530)	(154)	(65)
May-2004	(100)	(29)	(161)
Jun-2004	(279)	(81)	103
Jul-2004	(274)	(80)	62
Aug-2004	(293)	(85)	125
Sep-2004	(232)	(67)	220
Oct-2004	51	15	(15)
Nov-2004	51	15	(15)
Dec-2004	51	15	(15)
2004	(3,120)	(909)	830
Jan-2005	369	107	(107)
Feb-2005	369	107	(107)
Mar-2005	369	107	(107)
Apr-2005	369	107	(107)
May-2005	369	107	(107)
Jun-2005	369	107	(107)
Jul-2005	369	107	(107)
Aug-2005	369	107	(107)
Sep-2005	369	107	(107)
Oct-2005	369	107	(107)
Nov-2005	369	107	(107)
Dec-2005	(4,066)	(1,185)	1,185
2005	(11)	(3)	3
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0
2029	0	0	0

COLUMN NOTES:
(21) COLUMN (20) - COLUMN (7).
(22) COLUMN (21) * 29.13%.
(23) COLUMN (6) - COLUMN (22).

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY ELECTRIC SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS			BLACKSTONE VALLEY ELECTRIC COMPANY ACCOUNT							
YEAR	DEFERRAL OF CONTRACT TERMINATION DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	VARIABLE RECONCIL. ADJUSTMENT	DEFERRAL OF CONTRACT TERM. DATE	CREDIT FOR DIFF. BETWEEN 9.20%ROE & 11.4% ROE	BUYOUT SAVINGS	ANNUAL SHORTFALL/ (EXCESS)	ANNUAL PRE-TAX RETURN ON BALANCE	COLLECTION OF PRIOR YR BAL. INCL. INTEREST	END OF YR. ACCOUNT BALANCE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1999	0	0	0	0	0	0	0	0	0	0	(7,781)
2000	0	0	0	(4,021)	0	0	0	(4,021)	(789)	(7,781)	(4,810)
2001	0	0	0	(3,788)	0	0	0	(3,788)	(626)	(5,147)	(4,078)
2002	0	0	0	(497)	0	0	0	(497)	(251)	(3,784)	(1,041)
Jan-2003	0	0	0	(671)	0	0	0	(671)	(14)	(2)	(1,725)
Feb-2003	0	0	0	(267)	0	0	0	(267)	(19)	(2)	(2,009)
Mar-2003	0	0	0	(104)	0	0	0	(104)	(21)	(2)	(2,132)
Apr-2003	0	0	0	400	0	0	0	400	(20)	(2)	(1,749)
May-2003	0	0	0	305	0	0	0	305	(16)	(2)	(1,458)
Jun-2003	0	0	0	(117)	0	0	0	(117)	(15)	(2)	(1,589)
Jul-2003	0	0	0	(80)	0	0	0	(80)	(16)	(2)	(1,683)
Aug-2003	0	0	0	(215)	0	0	0	(215)	(18)	(2)	(1,915)
Sep-2003	0	0	0	(194)	0	0	0	(194)	(20)	(2)	(2,128)
Oct-2003	0	0	0	162	0	0	0	162	(21)	(2)	(1,985)
Nov-2003	0	0	0	77	0	0	0	77	(20)	(2)	(1,926)
Dec-2003	0	0	0	(2,101)	0	0	0	(2,101)	(30)	(2)	(4,055)
2003	0	0	0	(2,805)	0	0	0	(2,805)	(230)	(21)	(4,055)
Jan-2004	0	0	0	(594)	0	0	0	(594)	(43)	(194)	(4,499)
Feb-2004	0	0	0	(42)	0	0	0	(42)	(45)	(194)	(4,392)
Mar-2004	0	0	0	46	0	0	0	46	(43)	(194)	(4,196)
Apr-2004	0	0	0	65	0	0	0	65	(41)	(194)	(3,978)
May-2004	0	0	0	161	0	0	0	161	(39)	(194)	(3,663)
Jun-2004	0	0	0	(103)	0	0	0	(103)	(37)	(194)	(3,609)
Jul-2004	0	0	0	(62)	0	0	0	(62)	(36)	(194)	(3,513)
Aug-2004	0	0	0	(125)	0	0	0	(125)	(35)	(194)	(3,480)
Sep-2004	0	0	0	(220)	0	0	0	(220)	(35)	(194)	(3,542)
Oct-2004	0	0	0	15	0	0	0	15	(35)	(194)	(3,368)
Nov-2004	0	0	0	15	0	0	0	15	(33)	(194)	(3,192)
Dec-2004	0	0	0	15	0	0	0	15	(31)	(194)	(3,015)
2004	0	0	0	(830)	0	0	0	(830)	(453)	(2,324)	(3,015)
Jan-2005	0	0	0	107	0	0	0	107	(29)	(272)	(2,665)
Feb-2005	0	0	0	107	0	0	0	107	(25)	(272)	(2,311)
Mar-2005	0	0	0	107	0	0	0	107	(21)	(272)	(1,953)
Apr-2005	0	0	0	107	0	0	0	107	(18)	(272)	(1,592)
May-2005	0	0	0	107	0	0	0	107	(14)	(272)	(1,228)
Jun-2005	0	0	0	107	0	0	0	107	(11)	(272)	(859)
Jul-2005	0	0	0	107	0	0	0	107	(7)	(272)	(487)
Aug-2005	0	0	0	107	0	0	0	107	(3)	(272)	(111)
Sep-2005	0	0	0	107	0	0	0	107	1	(272)	269
Oct-2005	0	0	0	107	0	0	0	107	5	(272)	652
Nov-2005	0	0	0	107	0	0	0	107	9	(272)	1,039
Dec-2005	0	0	0	(1,185)	0	0	0	(1,185)	6	(272)	132
2005	0	0	0	(3)	0	0	0	(3)	(108)	(3,258)	132
2006	0	0	0	0	0	0	0	0	8	140	(0)
2007	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2008	0	0	0	0	0	0	0	0	(0)	(0)	0
2009	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	(0)
2011	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2012	0	0	0	0	0	0	0	0	(0)	(0)	0
2013	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	(0)
2015	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2016	0	0	0	0	0	0	0	0	(0)	(0)	0
2017	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	(0)
2019	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2020	0	0	0	0	0	0	0	0	(0)	(0)	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	(0)
2023	0	0	0	0	0	0	0	0	(0)	(0)	(0)
2024	0	0	0	0	0	0	0	0	(0)	(0)	0
2025	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) ACTUAL
(3) ACTUAL
(5) SEE SCHEDULE 2, PG. 1, COLUMN (23) X -1.
(9) SUM OF COLUMNS (5) THROUGH (8).
(10) COLUMN (12) PRIOR YEAR /2 x RETURN @ BTWACC.
(11) COLUMN (12) PRIOR YEAR + COLUMN (10) CURRENT YEAR.
(12) PRIOR YEAR COLUMN (12) + CURRENT YEAR COLUMN (9) AND (10) - COLUMN(11).

Attachment B

MARKED Version of
New England Power Company
Sixth Revised Service Agreement No. 23
with The Narragansett Electric Company

SERVICE AGREEMENT
Between
NEW ENGLAND POWER COMPANY
And
THE NARRAGANSETT ELECTRIC COMPANY

Tariff Submitter: New England Power Company
FERC Tariff Program: FERC FPA Electric Tariff
Tariff Title: Tariffs, Rate Schedules, Agreements
Tariff Record Title: New England Power Co. Service Agmt. No. 23
Option Code A
Issued by: William H. Malee~~Mary Ellen Paravalos~~ Proposed Effective Date: September 23~~January 1~~, ~~2010~~2014
Director, Transmission Commercial Services~~Vice President, New England Power Company~~
Issued on: July 24, 2014~~December 30, 2009~~

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

Dated: February 15, 1974

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

and

THE NARRAGANSETT ELECTRIC COMPANY
A Rhode Island corporation (the "Customer")

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

Schedule I - General Terms and Conditions

Schedule II - Rate Provisions

Schedule III - Terms and Conditions Governing Service

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

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

NONE

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

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By: ______________________________

THE NARRAGANSETT ELECTRIC COMPANY

By: ______________________________

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:	The Narragansett Electric Company
2. Name of District:	Capital and Coastal
3. Service Under:	Schedules III-B of the Tariff and Settlements accepted by the Commission in Docket Nos. ER97-680-000 and ER97-2800-000
4. Electric Utilities Served by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Massachusetts Electric Company
5. Electricity Purchased from Commercial and Industrial Establishments by the Customer as of the date of the Service Agreement: (Schedule I - Paragraph D)	Not Applicable. Narragansett Electric no longer takes generation service under Tariff No. 1. Contract Termination Charge provided pursuant to Contract Termination Charge Amendment.
6. Variations from Standard Delivery and Metering: (Schedule I - Paragraph G, 5)	Not applicable
7. Entitlements:	
A. On Customer System (Schedule III -C Paragraph C.2.(a))	None
B. Off Customer System (Schedule III-C Paragraph C.2.(b))	None
8. Customer Generation excluded from Firm Capacity Calculation: (Schedule III-C - Paragraph C.3.c.)	None
9. Firm Capacity: (Schedule III-C - Paragraph C.3.c.)	None

10. Integrated Generating, Transmission and Facilities Credits: (Schedule III-B - Paragraph B.4.b) — See Integrated Facilities Amendment

Payable by Company:

Customer Distribution Plant Assets Serving Wholesale Transmission Function (See Attachments X and X-1) :	$390,880
Block Island Transmission System (BITS) Assets Serving Wholesale Transmission Function (See Attachment X):	TBD upon completion
Customer Shared Substation Assets:	None
Customer Buildings and Facilities	None

Formula Rate Inputs:

1. Customer Post Retirement Benefits Other Than Pensions (PBOP) - ($9,000,000)

2. Customer Depreciation Rates

Transmission Accounts	Rate
352	1.41%
353	1.90%
354	0.00%
355	2.60%
356	2.29%
357	2.15%
358	2.47%
359	1.15%

Distribution Accounts	Rate
361	2.27%
362	1.97%
364	3.58%
365	3.20%
366	1.88%
367.1	3.43%
368	
368.1	3.78%
368.2	4.01%
368.3	4.05%

369	
369.1	3.44%
369.2	0.00%
369.21	0.00%
369.22	3.20%
370	
370.1	5.19%
370.2	5.29%
370.3	5.26%
370.35	4.90%
371	3.68%
373	
373.1	5.64%
373.2	5.65%

General Accounts	**Rate**
390	2.24%
391	1.37%
392	0.00%
393	2.67%
394	4.97%
395	4.26%
396	0.00%
397	6.67%
397.1	4.66%
398	2.87%

11. Primary Service for Resale:

None. LNS transmission service is provided by New England Power Company under ISO-NE~~P~~'s ~~Open Access~~ Transmission, Markets and Services Tariff (~~FERC Electric Tariff No. 39,~~ Schedule 21-NEP). Contract Termination Charge provided pursuant to Contract Termination Charge Amendment. Nothing contained herein is intended to modify or otherwise affect the settlements accepted by the Commission in Docket Nos. ER97-680-000 and ER97-2800-000. In the event of a conflict between the Contract Termination Charge Amendment and the settlements, the settlements shall govern.

12. Minimum Demand KW:	None
13. Minimum Term:	None
14. Transmission Service for Partial Requirements Customers:	LNS transmission service is provided by New England Power Company (NEP) to The Narragansett Electric Company under ISO-NE's ~~Open Access~~ Transmission, Markets and Services Tariff (~~FERC Electric Tariff No. 3,~~ Schedule 21-NEP.)

Attachment X

Customer Distribution Facilities and Block Island Transmission System Facilities Utilized by Company for Providing Transmission Service

1. Description of Distribution Facilities Serving Wholesale Transmission Function

The existing 34.5 kV mainland distribution facilities serving Block Island include:

- Wakefield 34.5kV Switchyard
- West Kingston 34.5kV Switchyard

A calculation of the plant value of these facilities as allocated for BIPCo service is attached as Exhibit X-1.

2. Description of Block Island Transmission System (BITS) Assets Serving Wholesale Transmission Function

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- 22 miles of 34.5 kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5 kV switching station on Block Island, including two switched reactors for voltage control;
- New 34.5 kV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately 0.86 miles of combined overhead and underground infrastructure on Block Island; and
- Approximately 2 miles of combined overhead and underground infrastructure on the mainland in the Town of Narragansett.

Attachment X-1

Calculation of shared value of 34.5kV distribution facilities in southern Rhode Island

LOAD (MW)	2013
Bonnet	8.8
Peacedale	21.5
Wakefield	27.7
URI	12.0
TOTAL TNECO (MW)	70.0
BIPCo	3.6
TOTAL LOAD (MW)	73.6

Component of Cost	(1) Gross Plant Value ($000)	(2) BIPCO Load Percentage	(3) BIPCO Share of Cost ($000)
Wakefield 34.5	$4,156	9%	$373.09
West Kingston 34.5	$364	5%	$17.78
		Total	$390.88

(1) From The Narragansett Electric Company's Plant Accounting Records
(2) BIPCO load divided by the cumulative load from Bonnet back to West Kingston along the 3307/3308 Path:
At Wakefield 3.6/(3.6+8.8+27.7),
At West Kingston 3.6/73.6
(3) = (1) * (2)

[The preceding sheets show all revisions made in the 6th Revised version of Service Agreement No. 23; the remainder of the agreement is unchanged and can be seen in the clean tariff text at Attachment A to this filing.]

FERC rendition of the electronically filed tariff records in Docket No. ER14-02493-000
Filing Data:
CID: C001305
Filing Title: New England Power Co. Filing of 6th Rev. Service Agmt. 23 with Narragansett
Company Filing Identifier: 160
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Tariffs, Rate Schedules, Agreements
Tariff ID: 78
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Narragansett S.A., New England Power Co. 6th Rev. Service Agreement 23, 0.0.0, A
Record Narative Name:
Tariff Record ID: 34
Tariff Record Collation Value: 2105038074 Tariff Record Parent Identifier: 0
Proposed Date: 2014-09-23
Priority Order: 500
Record Change Type: NEW
Record Content Type: 2
Associated Filing Identifier:

This is a PDF section and we cannot render PDF in a RTF document.

Document Content(s)

May 4, 2015

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

Re: New England Power Company
Docket No. ER15-1466-000
Errata to Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

On April 7, 2015, pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission's ("Commission")[2], New England Power Company d/b/a/ National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties") submitted amendments to two Local Service Agreements ("LSAs"), designated as First Revised Service Agreement No. TSA-NEP-83 and First Revised Service Agreement No. TSA-NEP-86, respectively, under the ISO-NE OATT.

Due to an administrative oversight, Attachments A-1 and B-1, the marked tariff attachments showing the proposed revisions to the LSAs, were omitted from the filing submitted on April 7. Therefore, the Filing Parties now resubmit the April 7 filing with its original transmittal letter and a complete set of the attachments specified in that letter as part of this errata filing.

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. Part 35.

The Filing Parties regret any inconvenience and request that the Commission accept the LSAs effective on the date requested in the April 7 filing, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
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950 F Street, NW
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/s/ Monica Gonzalez
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ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

April 7, 2015

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

Re: New England Power Company
Docket No. ER15-____-000
Filing of First Revised Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86 Under ISO-NE OATT

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") joined by ISO New England Inc. ("ISO-NE") (together, the "Filing Parties")[3] submit amendments to the following two Local Service Agreements ("LSAs"):

(1) the LSA among NEP, Block Island Power Company ("BIPCO"), and ISO New England Inc. ("ISO-NE"), designated as First Revised Service Agreement No. TSA-NEP-83 under the ISO-NE OATT; and

(2) the LSA among NEP, The Narragansett Electric Company ("Narragansett"), and ISO-NE, designated as First Revised Service Agreement No. TSA-NEP-86 under the ISO-NE OATT.

[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. Part 35.

[3] NEP, and not ISO-NE, has the FPA section 205 rights over Schedule 21-NEP of the ISO-NE Open Access Transmission Tariff ("OATT"), pursuant to which NEP offers and administers Local Service. ISO-NE does not offer or administer Local Service and joins this filing solely to fulfill its obligations to file Local Service Agreements on the applicable Participating Transmission Owner ("PTO"), in accordance with Article 3.03(d)(ii) of the Transmission Operating Agreement ("TOA") between ISO-NE and the PTOs. *See ISO New England Inc.*, 124 FERC ¶ 61,297 (2008).

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015

I. Background

The original LSAs were accepted by the Commission on September 2, 2014, by delegated letter order in Docket No. ER14-2514-000. The LSAs were executed in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1 ("Tariff No. 1").[4] The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[5] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[6]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[7]

[4] Pursuant to those integrated facilities provisions, NEP supports the cost of the transmission facilities of its affiliate Narragansett, and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE OATT.

[5] Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

[6] *Id.*, § 39-26.1-7(a).

[7] *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated

The Deepwater Block Island Wind, LLC ("Block Island Wind") generation project, a 30-megawatt (nameplate) demonstration-scale offshore wind facility, is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

As part of the package of Agreements necessary to implement the transaction and interconnect Block Island Wind to the mainland, NEP also filed, (1) a Large Generator Interconnection Agreement ("LGIA") with Block Island Wind which was accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2496-000 and (2) an amendment to Service Agreement No. 23 under NEP's Tariff No. 1 accepted by the Commission by delegated letter order on September 2, 2014, in Docket No. ER14-2493-000. NEP also terminated its previous Network Integration Transmission Service Agreement No. 108 with Narragansett which was part of the record in Docket No. ER14-2519.

for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

II. The LSAs

The LSAs being filed in this proceeding have been revised to address a concern raised by the Rhode Island Division of Public Utilities and Carriers ("Division") that the Block Island Transmission System ("BITS") Surcharge[8] calculated under the LSAs did not fully conform with the Rhode Island statute referenced above. Specifically, the Division was concerned that the calculation of the BIPCO Share Percentage did not fully comport with the Rhode Island General Law Section 39-26.7(f) which states:

> "The allocation of the costs related to the transmission cable through transmission rates or otherwise shall be structured so that the estimated impact on the typical residential customer bill for such transmission costs for customers in the Town of New Shoreham *shall be higher* than the estimated impact on the typical residential customer bill for customers on the mainland of the electric distribution company." (Emphasis added)

To address the issues raised by the Division, NEP modified the BITS Surcharge by introducing a collar to the calculation of the BIPCO Share Percentage such that the impact on the typical residential customer in the Town of New Shoreham cannot be lower than 120% of the impact on the typical residential customer of The Narragansett Electric Company. All parties have executed these First Revised LSAs to reflect that change. NEP is authorized to state the Division also supports this modification.

III. Effective Date

The Filing Parties request that the Commission accept the LSAs effective 61 days after the date of this filing, *i.e.*, June 7, 2015.

[8] *See* the BITS Surcharge provisions set forth in Part II, Section 2(p) of the LSAs and a referenced attachment in each LSA.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Executed First Revised Service Agreement No. TSA-NEP-83;
Attachment A-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-83 and Original Local Service Agreement No. TSA-NEP-83.
Attachment B	Executed First Revised Service Agreement No. TSA-NEP-86; and
Attachment B-1	Marked comparison between First Revised Service Agreement No. TSA-NEP-86 and Original Service Agreement No. TSA-NEP-86.

V. Description of the Filing Parties and Communications

NEP is a wholly owned subsidiary of National Grid USA. NEP is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a PTO under the terms of the TOA by and among the New England PTOs and ISO-NE. All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of Section II of the ISO-NE Tariff.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. ISO-NE operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the ISO-NE Transmission, Markets and Services Tariff and the Transmission Operating Agreement with the New England transmission owners. In its capacity as an RTO, ISO-NE also has the objective to assure that the bulk power supply system within the New England Control Area conforms to proper standards of reliability as established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

Communications and correspondence regarding this filing should be addressed to the following individuals:

NEP:

Daniel Galaburda
Assistant General Counsel
and Director
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451
(781) 907-2422
daniel.galaburda@nationalgrid.com

Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004
(202) 239-3300
kenneth.jaffe@alston.com
bradley.miliauskas@alston.com

William L. Malee
Director of Transmission
Commercial Services
National Grid USA
40 Sylvan Road
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(781) 907-2422
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Amanda C. Downey
Counsel
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451
(781) 907-2136
amanda.downey@nationalgrid.com

ISO-NE:

Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
(413) 535-4000
Fax: (413) 535-4379
mgonzalez@iso-ne.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, the Rhode Island Division of Public Utilities and Carriers, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, the Filing Parties request that the Commission accept them effective 61 days from the date of filing, *i.e.*, June 7, 2015. Please contact the undersigned with any questions regarding this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe
Kenneth G. Jaffe
Bradley R. Miliauskas
Alston & Bird LLP
The Atlantic Building
950 F Street, NW
Washington, DC 20004

Amanda C. Downey
Counsel
National Grid USA
Service Company, Inc.
40 Sylvan Road
Waltham, MA 02451

Attorneys for New England Power Company d/b/a National Grid

/s/ Monica Gonzalez
Monica Gonzalez
Senior Regulatory Counsel
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

Attorney for ISO New England Inc.

ATTACHMENT A

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

BLOCK ISLAND POWER COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21
ATTACHMENT A
FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), Block Island Power Company, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

  __ Firm

  __ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
Block Island Power Company
Attn: Clifford R. McGinness
100 Ocean Avenue
Block Island, RI 02807

Transmission Owner:
New England Power Company
Attn: Director, Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.

2. Service shall commence on the later of: (l) January 1, 2016 or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on December 31, 2035, or as otherwise mutually agreed in writing by the parties.

3. Specifications for Local Network Service.

   a. Term of Service: See 2 above.

   b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
Initially up to 4.6 MW and 15TWh of Network Load

d. Description of Local Network Load:
Wholesale load for the Town of New Shoreham, Rhode Island

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
At the Transmission Owner's Affiliate's 34.5 kV substation on Block Island.
Note: The metering is on the 34.5 kV side and the Transmission Owner owns the meter.

f. List of non-Network Resource(s), to the extent known:

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer will execute a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:
1-34.5kV breaker, 1-34.5/4.16kV/2.4kV transformer, 5kV insulated line to customer substation and associated equipment.

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

At 34.5kV at the Transmission Owner's Affiliate's 34.5kV substation on Block Island.

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

Any and all other applicable charges in accordance with the rates, terms and conditions of Schedule 21-NEP of the Tariff, including, without limitation:

- Monthly demand charges with PTF and non-PTF components
- Transformer surcharge
- Rolled-In Distribution Surcharge
- Direct Assignment Facilities Charge for interconnection facilities in i. above
- Meter Surcharge
- Network load dispatch surcharge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 1)

q. Additional terms and conditions:

Transmission Customer grants permission to Transmission Owner's engineering, distribution planning, transmission planning and T&D operations personnel to access any and all Transmission Customer RTU data which is telemetered to Transmission Owner's control room. Transmission Owner agrees not to share this data with its sales and marketing personnel.

Transmission Customer understands that the source to the 34.5 kV Block Island substation is a radial feed from the Transmission Owner's Affiliate's Wakefield Substation and that there will be an interruption to network service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable.

4. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practices for protection requirements for new or modified load interconnections.

See Attachment E of Transmission Owner's Local Service Schedule 21- NEP

7. Insurance requirements.

See Attachment F of Transmission Owner's Local Service Schedule 21- NEP

PART III – Local Point-To-Point Service (N/A)

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

a. Term of Transaction:

b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: C.R. McGinnes | V. President + COO | 1/22/15
Name | Title | Date

C.R. McGINNES
Print Name

Transmission Owner:

By: William L Malee | Authorized Representative | 1/8/15
Name | Title | Date

William L Malee
Print Name

The ISO:

By: | V.P. System Planning | 1/30/15
Name | Title | Date

Print Name

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio Collar:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT A-1

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit for BITS facilities multiplied by the BIPCO Share Percentage, where:

1. The IFA Facilities Credit for BITS facilities shall become effective as of the commercial operation date of the BITS facilities and shall equal the monthly integrated facilities credit for Customer-owned distribution facilities rendered to The Narragansett Electric Company for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The BIPCO Share Percentage for each year shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share ~~or its Energy Ratio Share from the prior calendar year~~. The BIPCO Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according to the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + TNECO Annual Peak Load)

4. BIPCO's Energy Ratio ~~Share~~ Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of BIPCO's Annual Peak Load Ratio Share and its Energy Ratio ~~Share~~Collar:

Illustrative Example:

2010 Annual Peak Load ~~Results~~

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy ~~Results~~Ratio Collar

(1) 1.2* BIPCO Annual Energy =	13,369,466 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,765,256,466 kWh

(4) Minimum Energy Ratio Share ((1)/(3)) = 0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	7,751,887,000 kWh
(3) Total Annual Energy	7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, Transmission Customer's Share Percentage in this example would be 0.19508%.

ATTACHMENT B

LOCAL SERVICE AGREEMENT

BY AND BETWEEN

NEW ENGLAND POWER COMPANY;

THE NARRAGANSETT ELECTRIC COMPANY

AND

ISO NEW ENGLAND INC.

SCHEDULE 21

ATTACHMENT A

FORM OF LOCAL SERVICE AGREEMENT

This LOCAL SERVICE AGREEMENT, dated as of February 1, 2015, is entered into, by and between New England Power Company d/b/a National Grid, a corporation organized and existing under the laws of the Commonwealth of Massachusetts ("Transmission Owner"), The Narragansett Electric Company d/b/a/ National Grid, a corporation organized and existing under the laws of the State of Rhode Island ("Transmission Customer") and ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("ISO"). Under this Agreement the Transmission Owner, Transmission Customer, and the ISO each may be referred to as a "Party" or collectively as the "Parties."

PART I – General Terms and Conditions

1. Service Provided (Check applicable):

X Local Network Service

__ Local Point-To-Point Service

__ Firm

__ Non-Firm

Regional Network Service customers must take either Local Network Service or Local Point-To-Point Service.

2. The Transmission Customer is an Eligible Customer under the Tariff and is a party to either a Market Participant Service Agreement or a Transmission Service Agreement.

3. The Transmission Customer has submitted a Completed Application and the required deposit, if applicable, for service under this Local Service Agreement and the Tariff.

4. The Transmission Customer agrees to supply information to the Transmission Owner that the Transmission Owner deems reasonably necessary in accordance with Schedule 21 and Good Utility Practice in order for it to receive the requested service.

5. The Transmission Owner agrees to provide and the Transmission Customer agrees to take

and pay for service in accordance with the provisions of the Tariff and this Local Service Agreement.

6. Service may be subject to some combination of the charges detailed in Schedule 21 of the OATT. The appropriate charges will be determined in accordance with the terms and conditions of Schedule 21.

7. Any notice or request made to or by either party regarding this Local Service Agreement shall be made to the representative of the other party as indicated below.

Transmission Customer:
The Narragansett Electric Company
Attn: Mary K. Smith
280 Melrose Street
Providence, RI 02907

Transmission Owner:
New England Power Company
Attention: Transmission Commercial
40 Sylvan Road
Waltham, MA 02451

The ISO:
ISO New England Inc.
Attn: Manager - Transmission Services
One Sullivan Road
Holyoke, MA 01040

8. The ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff") is incorporated herein and made a part hereof. Capitalized terms used in this Local Service Agreement shall have the meanings ascribed in the Tariff.

9. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the right of the Transmission Owner to file with the Commission under Section 205

of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement. Nothing contained in this Local Service Agreement shall be construed as affecting in any way the ability of the Transmission Customer to file with the Commission under Section 206 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions of this Local Service Agreement.

10. Nothing contained in this Local Service Agreement shall be construed as affecting or enlarging, in whole or in part, the limited responsibility of the ISO under the Transmission Operating Agreement ("TOA") to coordinate the Transmission Owner's provision of Local Service and to determine whether the provision of Local Service would have an impact on facilities used for the provision of Regional Transmission Service.

PART II – Local Network Service

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Network Service under the Tariff.
2. Service shall commence on the later of: (l) the date that termination becomes effective for the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997, by and between New England Power Company and The Narragansett Electric Company, or (2) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or facility or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on or after the date that Contract Termination Charges, defined and set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and Transmission Owner under the Transmission Owner's FERC Electric Tariff, Original Volume 1 filed on May 30, 1997 in Docket No. ER97-680-000 and conditionally approved by the Commission on November 26, 1997(the "Restructuring Agreements"), are fully recovered from the Transmission Customer. Following that date, service under this Local Service Agreement shall continue until modified or terminated upon the written consent of the parties or upon five years advance written notice by any party to the others.

3. Specifications for Local Network Service.

a. Term of Service: See 2 above.

b. List of Network Resources and Point(s) of Receipt:

c. Description of capacity and energy to be transmitted:
1.8 GW and 7800 GWh

d. Description of Local Network Load:

e. List of Point(s) of Delivery and metering point(s) when they differ from Point(s) of Delivery:
See Attachment 1

f. List of non-Network Resource(s), to the extent known:
None

g. Ancillary Services requested or proof of satisfactory arrangements for Ancillary Services:
The Transmission Customer has executed a Market Participant Service Agreement or a Transmission Service Agreement with ISO-New England, Inc.

h. Identity of Designated Agent:

Authority of Designated Agent:

Term of Designated Agent's authority:

Division of responsibilities and obligations between Transmission Customer and Designated Agent:

i. Interconnection facilities and associated equipment:

j. Project name:

k. Interconnecting Transmission Customer:

l. Location:

m. Transformer nameplate rating:

n. Interconnection point:

o. Additional facilities and/or associated equipment:

p. Service under this Local Service Agreement shall be subject to the following charges:

As of the execution date of this Local Service Agreement, the Schedule 21-NEP charges include a:

- Monthly demand charge with PTF and non-PTF components
- Transformer surcharge
- Meter surcharge
- Network load dispatch surcharge
- Third party support payments
- Direct Assignment Facility charge
- Block Island Transmission System ("BITS") Surcharge (pursuant to Attachment 2)

q. Additional terms and conditions:

This Local Service Agreement amends and replaces the Network Integration Transmission Service ("NITS") Agreement, dated as of February 1, 1997 and entered into by and between New England Power Company and The Narragansett Electric Company for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Restructuring Act of 1996 ("URA"). Pursuant to the NITS Agreement, the following terms and conditions will remain in effect under the terms of this Local Service Agreement:

(i) In the event that Transmission Customer is denied recovery in its rates for local distribution service of access charges sufficient to collect the full amount of the Contract Termination Charges billed to Transmission Customer, its successors or assigns, by Transmission Owner, its successors or assigns, Transmission Owner, its successors or assigns, providing service over the transmission facilities covered by this Local Service Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Local Service Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

(ii) The obligations under this Local Service Agreement may be assigned only with the express written consent of the other parties, which consent shall not be unreasonably withheld, provided, however, that the Transmission Owner shall not be obligated to consent to any assignment that adversely affects the ability of the Transmission Owner to recover from the Transmission Customer the payments required to be made under the Tariff, and this Local Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to the paragraph above.

(iii)The Transmission Owner has agreed to terminate those requirements of its FERC Electric Tariff, Original Volume No. 1 ("Tariff No. 1") that obligate the Transmission Customer to buy all of its electricity requirements under Tariff No. 1 and Transmission Customer has agreed to pay Contract Termination Charges pursuant to the Restructuring Agreements.

(iv)In no event shall the Transmission Owner bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

(v) To the extent ISO New England, Inc. or NEPOOL does not directly bill the Transmission Customer, any charges by ISO New England, Inc. or NEPOOL specifically incurred by the Transmission Owner, as a result of services provided to the Transmission Customer, will be directly assigned to the Transmission Customer as provided for under Section 24.6 of Schedule 21-NEP. The Transmission Owner will determine the direct charges to the Transmission Customer on the basis of the Transmission Customer's contribution to the incurrence of those charges using the same allocation methodology used by ISO New

England, Inc. or NEPOOL to allocate those costs to the Transmission Owner.

4. Planned work schedule.

Estimated Time

Milestone	Period For Completion
(Activity)	(# of months)

5. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

6. Policy and practiccs for protcction requirements for new or modified load interconnections.

7. Insurance requirements.

PART III – Local Point-To-Point Service N/A

1. The Transmission Customer has been determined by the Transmission Owner and the ISO to have a Completed Application for Local Point-To-Point Service under the Tariff.

2. Service shall commence on the later of: (l) ________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Local Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service shall terminate on __________________.

3. Non-firm Local Point-To-Point Service shall be provided by the Transmission Owner upon request by an authorized representative of the Transmission Customer.

4. Specifications for Local Point-To-Point Service.

   a. Term of Transaction:

   b. Description of capacity and energy to be transmitted by the Transmission Owner including the electric Control Area in which the transaction originates:

c. Point(s) of Receipt:

d. Delivering Party:

e. Point(s) of Delivery:

f. Receiving Party:

g. Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

h. Designation of party(ies) subject to reciprocal service obligation:

i. Name(s) of any intervening Control Areas providing transmission service:

j. Service under this Local Service Agreement shall be subject to the following charges:

k Interconnection facilities and associated equipment:

l. Project name:

m. Interconnecting Transmission Customer:

n. Location:

o. Transformer nameplate rating:

p. Interconnection point:

q. Additional facilities and/or associated equipment:

r. Additional terms and conditions:

5. Planned work schedule.

Estimated Time

Milestone (Activity)	Period For Completion (# of months)

6. Payment schedule and costs.

(Study grade estimate, +___% accuracy, year $s)

Milestone	Amount ($)

7. Policy and practices for protection requirements for new or modified load interconnections.

8. Insurance requirements.

IN WITNESS WHEREOF, the Parties have caused this Local Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: ______________ President 1/12/15

Name Title Date

Timothy F. Horan

Print Name

Transmission Owner:

By: ______________ Authorized Representative 1/12/15

Name Title Date

William L Malee

Print Name

The ISO:

By: ______________ V.P. System Planning 1/21/15

Name Title Date

Stephen J. Rourke

Print Name

Attachment 1

The Narragansett Electric Company

Points of Delivery

Main District
Admiral Street Substation
Blackburn Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
EMI Tiverton Station Service
Farnum Pike Substation
FPL RISEP Station Service
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Kilvert Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation
Point Street Substation
Pontiac Substation
Putnam Pike
Sockanosset Substation
South Street Station
Tiverton Substation
Tower Hill Substation
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation
Woonsocket Substation

Blackstone Valley
Nasonville B23 Line from W. Farnum
West Farnum tap off 174
Farnum off H 17 Line
Riverside - R9/J16/H17
Pawtucket No. 1 Station X3/P11/T7
Staples J16/Q10
Vallev R9P11
Washington V148 from Robinson Ave
Ocean State Power Station Service

Newport
Canonicus St. M13L14

Attachment 1

Metering Points (To the extent they differ from a Point of Delivery)

Main District
Pawtucket Power
Johnston Landfill
Valley Hydro
Cranston Landfill

Blackstone Valley
Roosevelt Hydro
Blackstone Hydro, Inc.
Blackstone Hydro Assoc.
Pawtucket #2 Hydro
Woonsocket Hydro

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO Share Percentage. The BIPCO Share Percentage shall be BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW
(3) Total Annual Peak Load =	1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh

(2) TNECO Annual Energy =	<u>7,751,887,000 kWh</u>
(3) Total Annual Energy	7,765,256,466 kWh
(4) Minimum Energy Ratio Share ((1)/(3)) =	0.17217%

(1) 1.8* BIPCO Annual Energy =	20,054,199 kWh
(2) TNECO Annual Energy =	<u>7,751,887,000 kWh</u>
(3) Total Annual Energy	7,771,941,199 kWh
(4) Maximum Energy Ratio Share ((1)/(3)) =	0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

ATTACHMENT B-1

Attachment 2

Block Island Transmission System (BITS) Surcharge

This Attachment 2 applies to charges under the Tariff for Block Island Transmission System ("BITS") facilities owned or leased by the Transmission Customer, and constructed to interconnect Block Island Power Company ("BIPCO") and Deepwater Block Island Wind, LLC to the New England Transmission System. In accordance with the Rhode Island General Laws, § 39-26.1-7(f), the annual costs incurred by the Transmission Customer for the BITS facilities shall be recovered annually from its customers and/or from Block Island Power Company ("BIPCO") through a fully reconciling rate adjustment, subject to any federal approvals that may be required by law.

In addition to the other applicable charges specified for Local Network Service under Schedule 21-NEP of the Tariff, the Transmission Customer shall pay the Block Island Transmission System Surcharge ("BITS Surcharge") as set forth in this Attachment.

Description of Block Island Transmission System Facilities

For purposes of this Attachment, the BITS facilities, determined in accordance with the Rhode Island General Laws § 39-26.1-7(f), shall include the transmission cable between the Town of New Shoreham and the mainland of the state and related facilities. BITS is comprised of:

- Approximately 20 miles of 34.5kV submarine cable with fiber optic (communication) cable between the Town of New Shoreham and the mainland;
- New 34.5KVsubstation on Block Island, including two switched reactors for voltage control;
- New 34.5KV switching in Narragansett, RI, including two switched reactors for voltage control;
- Approximately one mile of combined overhead and underground infrastructure on Block Island; and
- Approximately 4 miles of underground infrastructure on the mainland in the Town of Narragansett.

Calculation of BITS Surcharge

The monthly BITS Surcharge shall equal the product of the IFA Facilities Credit multiplied by the Transmission Customer's Share Percentage, where:

1. The IFA Facilities Credit shall equal the monthly integrated facilities credit for Customer-owned distribution facilities received by the Transmission Customer for the BITS facilities pursuant to Schedule III-B of New England Power Company's FERC Electric Tariff No. 1. The IFA Facilities Credit amount will be updated annually in accordance with the provisions of Tariff No. 1, on or about the June billing month of each year.

2. The Transmission Customer Share Percentage shall be 1 minus the BIPCO ~~Load Ratio~~ Share Percentage. The BIPCO ~~Load Ratio~~ Share Percentage shall be ~~the lower of~~ BIPCO's Annual Peak Load Ratio Share from the prior calendar year as long as BIPCO's Annual Peak Load Ratio Share falls within a range specified by the BIPCO Energy Ratio Collar. If the Annual Peak Load Ratio Share so calculated is less than the Minimum Energy Ratio Share, the BIPCO Share Percentage will be set at the Minimum Energy Ratio Share. If the Annual Peak Load Ratio Share so calculated is greater than the Maximum Energy Ratio Share, the BIPCO Share Percentage will be set at the Maximum Energy Ratio Share. ~~or its Energy Ratio Share from the prior calendar year.~~ The Transmission Customer Load Ratio Share Percentage shall be reset annually during the same month that the IFA Facilities Credit is updated.

3. BIPCO's Annual Peak Load Ratio Share shall be determined as a percentage according the following formula:

   BIPCO Annual Peak Load / (BIPCO Annual Peak Load + Transmission Customer Annual Peak Load)

4. BIPCO's Energy Ratio Collar shall be the range between the Minimum Energy Ratio Share and the Maximum Energy Ratio Share, each as determined as a percentage according to the following formula:

   Minimum Energy Ratio Share
   1.2 * BIPCO Annual kWh / (1.2 * BIPCO Annual kWh + TNECO Annual kWh)

   Maximum Energy Ratio Share
   1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + TNECO Annual kWh)

~~4. BIPCO's Energy Ratio Share shall be determined as a percentage according the the following formula:~~

   ~~1.8 * BIPCO Annual kWh / (1.8 * BIPCO Annual kWh + Transmission Customer Annual kWh)~~

The following illustrates the calculation of Transmission Customer's Share Percentage:

Illustrative Example:

2010 Annual Peak Load

(1) BIPCo Annual Peak Load =	3,604 kW
(2) TNECO Annual Peak Load =	1,843,989 kW

(3) Total Annual Peak Load = 1,847,489 kW

(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%

2010 Energy Ratio Collar

(1) 1.2* BIPCO Annual Energy = 13,369,466 kWh
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(3) Total Annual Energy 7,771,941,199 kWh

(4) Maximum Energy Ratio Share ((1)/(3)) = 0.25803%

Since the Annual Peak Load Ratio falls within the range identified by the Energy Ratio Collar, the BIPCO Share Percentage in this example would be 0.19508%.

~~*2010 Peak Load Results*~~

~~(1) BIPCo Annual Peak Load = 3,604 kW~~
~~(2) Transmission Customer Annual Peak Load = 1,843,989 kW~~
~~(3) Total Annual Peak Load = 1,847,489 kW~~

~~(4) BIPCo Annual Peak Load Ratio Share ((1)/(3)) = 0.19508%~~

~~*2010 Energy Results*~~

~~(1) 1.8* BIPCO Annual Energy = 20,054,199 kWh~~
~~(2) Transmission Customer Annual Energy = 7,751,887,000 kWh~~
~~(3) Total Annual Energy 7,771,941,199 kWh~~

~~(4) BIPCO Energy Ratio Share ((1)/(3)) = 0.25803%~~

Transmission Customer's Share Percentage = 1 - 0.19508% = 99.80492%.

FERC rendition of the electronically filed tariff records in Docket No. ER15-01466-001
Filing Data:
CID: C000029
Filing Title: Errata to Filing of First Rev Service Agreement Nos. TSA-NEP-83 and TSA-NEP-86
Company Filing Identifier: 476
Type of Filing Code: 130
Associated Filing Identifier: 467
Tariff Title: ISO New England Inc. Agreements and Contracts
Tariff ID: 2
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Block Island LSA, LSA - TSA-NEP-83 NEP, Block Island Power and ISO-NE, 2.0.0, A
Record Narative Name: LSA Agreement by and between New England Power Co., Block Island Power Company and ISO-NE
Tariff Record ID: 59
Tariff Record Collation Value: 532232678 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-07
Priority Order: 550
Record Change Type: CHANGE
Record Content Type: 2
Associated Filing Identifier: 467

This is a PDF section and we cannot render PDF in a RTF document.
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Narragansett LSA, LSA - TSA-NEP-86 NEP, Narragansett and ISO-NE, 2.0.0, A
Record Narative Name: Local Service Agreement TSA-NEP-86 by and between New England Power Co., The Narragansett Electric Company and ISO-NE
Tariff Record ID: 60
Tariff Record Collation Value: 532242678 Tariff Record Parent Identifier: 0
Proposed Date: 2015-06-07
Priority Order: 550
Record Change Type: CHANGE
Record Content Type: 2
Associated Filing Identifier: 467

This is a PDF section and we cannot render PDF in a RTF document.

Document Content(s)

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July 24, 2014

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

Re: New England Power Company
Docket No. ER14-____-000
Filing of Large Generator Interconnection Agreement
With Deepwater Block Island Wind, LLC

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] and Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] New England Power Company d/b/a National Grid ("NEP") submits for filing a Large Generator Interconnection Agreement ("LGIA") between NEP and Deepwater Block Island Wind, LLC ("Block Island Wind").[3] The purpose of the LGIA is to interconnect the Block Island Wind generation project to a 34.5 kV substation to be constructed on Block Island and owned by NEP's affiliate, The Narragansett Electric Company d/b/a/ National Grid ("Narragansett"). The generation project and the new substation on Block Island are to be connected to the Rhode Island mainland by a 34.5 kV undersea cable being constructed pursuant to the Town of New Shoreham Project bill enacted into

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1 16 U.S.C. § 824d.

2 18 C.F.R. Part 35.

3 The LGIA is designated as Original Service Agreement No. IA-NEP-26 under Schedule 21 – NEP to Section II (Open Access Transmission Tariff) of the ISO New England Inc. Transmission, Markets and Services Tariff. As discussed below, NEP believes the LGIA is likely subject to the Commission's jurisdiction.

Rhode Island state law in 2009.[4] NEP requests that the Commission accept the LGIA effective 61 days after the date of this filing, *i.e.*, September 23, 2014.

I. Background

A. Parties to the LGIA

NEP, a wholly-owned subsidiary of National Grid USA, is a public utility subject to the Commission's jurisdiction that owns transmission facilities located in New England. NEP's primary business is the transmission of electricity at wholesale to electric utilities and municipalities in New England. NEP operates transmission facilities that it owns directly as well as certain transmission facilities owned by its distribution affiliates in New England pursuant to integrated facilities agreements under NEP's FERC Electric Tariff No. 1. NEP acts as the transmission provider for itself and its New England distribution affiliates. NEP is a Participating Transmission Owner ("PTO") under the terms of the Transmission Operating Agreement ("TOA") by and among the New England PTOs and ISO New England Inc. ("ISO-NE"). All of NEP's transmission facilities, including those owned by its New England distribution affiliates, are subject to the operating authority of ISO-NE under the terms of the TOA and are available for open access transmission service under the terms of the ISO-NE Open Access Transmission Tariff set forth in Section II of ISO-NE's Transmission, Markets and Services Tariff ("ISO-NE Tariff").

Narragansett, a wholly-owned subsidiary of National Grid USA and an affiliate of NEP, is a public utility primarily in the business of providing electric and gas distribution service in the State of Rhode Island. Pursuant to state law, Narragansett owns all National Grid transmission facilities located in Rhode Island. Pursuant to the integrated facilities provisions of NEP's FERC Electric Tariff No. 1, NEP supports the cost of Narragansett's transmission facilities and Narragansett makes its transmission facilities available to be controlled and operated by NEP so that the transmission facilities of NEP and NEP's New England distribution affiliates are operated on an integrated basis and made available for open access transmission service in accordance with the ISO-NE Tariff.

Block Island Wind is a limited liability company unaffiliated with NEP and Narragansett that is developing the Block Island Wind project, a 30 megawatt (nameplate) demonstration-scale offshore wind facility that will be located approximately three miles southeast of Block Island.[5]

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4 *See* Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

5 Block Island is part of Rhode Island and is coextensive with the Town of New Shoreham. The electric distribution needs of Block Island are served by Block Island Power Company ("BIPCO").

B. The Town of New Shoreham Project

The Town of New Shoreham Project is a public policy project authorized and directed by a Rhode Island statute of the same name.[6] The statute directs that:

> it is in the public interest for the state to facilitate the construction of a small-scale offshore wind demonstration project off the coast of Block Island, including an undersea transmission cable that interconnects Block Island to the [Rhode Island] mainland in order to: position the state to take advantage of the economic development benefits of the emerging offshore wind industry; promote the development of renewable energy sources that increase the nation's energy independence from foreign sources of fossil fuels; reduce the adverse environmental and health impacts of traditional fossil fuel energy sources; and provide the Town of New Shoreham with an electrical connection to the mainland.[7]

The statute authorizes and sets forth a process for developing the Town of New Shoreham Project, an associated power purchase agreement, transmission arrangements, and recovery of related costs. It also permits Narragansett, at its option, to own, operate, or otherwise participate in the transmission cable project.[8]

The Block Island Wind project is the offshore wind demonstration project described in the statute. Narragansett has agreed to construct, own, and operate the undersea cable between Block Island and the mainland and related facilities, which include a substation to be built on Block Island that will interconnect the Block Island Wind project to Narragansett's existing 34.5 kV system on the mainland. In addition, BIPCO, serving the Town of New Shoreham on Block Island, will interconnect to the same substation and will be electrically interconnected to the mainland for the first time by the same undersea cable. The cable will allow power to flow either from the Block Island Wind project to Block Island to the Rhode Island mainland, or from generators

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6 Town of New Shoreham Project, R.I. Gen. Laws § 39-26.1-7 (Supp. 2010).

7 *Id.*, § 39-26.1-7(a).

8 *Id.*, § 39-26.1-7(f). The statute specifies that "all costs incurred in the negotiation, administration, enforcement, transmission engineering associated with the design of the cable, and implementation of the project and agreement shall be recovered annually by the electric distribution company [*i.e.*, Narragansett] in electric distribution rates." *Id.*, § 39-26.1-7(d). The statute also directs that, should Narragansett own, operate, and maintain the cable, "the annual costs incurred by [Narragansett] directly or through transmission charges shall be recovered annually through a fully reconciling rate adjustment from customers of [Narragansett] and/or from the Block Island Power Company or its successor, subject to any federal approvals that may be required by law." *Id.*, § 39-26.1-7(f). Further, "[t]he revenue requirement for the annual cable costs shall be calculated in the same manner that the revenue requirement is calculated for other transmission facilities in Rhode Island for local network service under the jurisdiction of the federal energy regulatory commission." *Id.*

located on the mainland to Block Island, as needed. The Town of New Shoreham Project is currently estimated to be completed by late 2016.

C. Related Submittals to the Commission

In addition to the instant filing, NEP will separately file a revision to the service agreement between NEP and Narragansett (Service Agreement No. 23) in order to include the Town of New Shoreham Project under the integrated facilities provisions of NEP's FERC Electric Tariff No. 1.

Also, NEP will: (1) terminate its current Network Integration Transmission Service Agreement No. 108 with Narragansett and replace it with the current form of service agreement under Schedule 21 to Section II of the ISO-NE Tariff known as the Local Service Agreement ("LSA") with Narragansett, including ISO-NE as a party (Original Service Agreement No. TSA-NEP-86); and (2) execute a new LSA among NEP, BIPCO, and ISO-NE (Original Service Agreement No. TSA-NEP-83). Whether these service agreements are reported in Electric Quarterly Reports (EQRs) or separately filed with the Commission will depend on whether the agreements fully conform with the *pro forma* LSA under Schedule 21 (common provisions) to Section II of the ISO-NE Tariff.

II. The LGIA

A. LGIA Provisions

NEP and Block Island Wind have entered into the LGIA to provide for interconnection service from the Block Island Wind project to a 34.5 kV substation to be constructed on Block Island and owned by Narragansett. The generation project and the new substation on Block Island will be connected to a new 34.5 kV undersea cable that will be constructed between Block Island and the mainland which, in turn, will connect with Narragansett's existing 34.5 kV system.

The provisions in the body of the LGIA largely follow the provisions in the body of the *pro forma* Large Generator Interconnection Agreement set forth in Appendix 6 of Schedule 22 to Section II of the ISO-NE Tariff. The main difference between these provisions of the LGIA and the *pro forma* agreement is that the LGIA is a two-party agreement between the transmission owner (NEP) and the generation facility owner (Block Island Wind), whereas the *pro forma* agreement is a three-party agreement among the transmission owner, the generation facility owner, and ISO-NE.[9]

In addition, the Interconnection Product Options in Article 4 of the *pro forma* agreement are not applicable and have been removed because of ISO-NE's determination

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[9] Attachment B to this filing shows the differences between the LGIA and the *pro forma* Large Generator Interconnection Agreement in black-line format.

that the point of interconnection under the LGIA will reside on distribution facilities that are not currently part of the ISO-NE Administered Transmission System. References to Capacity Network Resource Interconnection Service, Network Resource Interconnection Service, and related provisions also do not apply and have been removed. Block Island Wind's eligibility for participating in the ISO-NE markets will be established pursuant to ISO-NE's Market Rule I (ISO-NE Tariff Section III).

Appendices A through C to the LGIA set forth provisions regarding the construction, ownership, maintenance, and cost of interconnection facilities and other provisions specific to the design and implementation of the Town of Shoreham project. These include provisions regarding Block Island Wind's responsibility for direct assignment facilities ("DAF") charges calculated in accordance with the existing formulae contained in Attachment DAF of Schedule 21 – NEP to Section II of the ISO-NE Tariff. The appendices specify that the point of interconnection ultimately will be where the parties' interconnection facilities connect to a 34.5 kV substation that Narragansett will construct and own on Block Island as the terminus of the cable that will link Block Island with the mainland.

Appendices D through G to the LGIA set forth provisions that follow the corresponding provisions in the *pro forma* Large Generator Interconnection Agreement regarding security arrangement details, commercial operation date, contact information, and interconnection requirements for a wind generating plant.

B. Commission Jurisdiction over the LGIA

ISO-NE is not a party to the LGIA on the grounds that the existing 34.5 kV facilities on the mainland are currently distribution facilities which have not previously been used for any transmission in interstate commerce under the Commission's jurisdiction. Under the ISO-NE Tariff, the Block Island Wind generation project will be interconnecting to a distribution facility that is not currently part of the ISO-NE Administered Transmission System and therefore is not subject to Schedule 22 to Section II of the ISO-NE Tariff, which only applies to interconnections to the Administered Transmission System.[10] Regardless of whether ISO-NE is a party to the LGIA, NEP believes the LGIA is subject to Commission jurisdiction and therefore is filing it with the Commission.

Section 205 of the FPA authorizes the Commission to require utilities to file all rates and charges that are "for or in connection with," and all agreements that "affect or

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[10] Pursuant to NEP's statements to ISO-NE that Narragansett's existing 34.5 kV distribution substation on the mainland to which the undersea cable and related facilities will be connected was not part of the Administered Transmission System at the time Block Island Wind requested interconnection and is not currently part of the Administered Transmission System, ISO-NE determined that the interconnection of the Block Island Wind project is not subject to Schedule 22 of Section II of the ISO OATT and therefore ISO-NE need not be a party to the LGIA.

relate to," jurisdictional transmission service or sales of electric energy.[11] NEP believes the LGIA affects or relates to jurisdictional service or sales. The point of interconnection for the Block Island Wind project will be to a substation on Block Island that, once constructed, will exist solely to serve a jurisdictional wholesale electric service function. The sole purpose of the substation and the bidirectional submarine cable between Block Island and the mainland will be to: (1) serve BIPCO as a new transmission customer taking regional and local network transmission service under the ISO-NE Tariff and (2) transmit electricity generated by the Block Island Wind generation project to the mainland for resale. No distribution function will be served by these new transmission facilities, the existence of which has been initiated for public policy reasons by the State of Rhode Island under the Town of New Shoreham Project Act. The LGIA is necessary to facilitate these purposes. Therefore, the LGIA appears to affect or relate to jurisdictional service or sales pursuant to Section 205 of the FPA.

The Commission has also directed that agreements should be filed with the Commission if there is any uncertainty as to the obligation to file such agreements.[12] NEP believes it is likely, though not certain, that the LGIA is jurisdictional.

While NEP acknowledges that ISO-NE's reasoning is consistent with the so-called "first-in-line" rule, we believe this rule would be inapplicable to this LGIA. The first-in-line rule states that an interconnection is not jurisdictional if it interconnects a generator to distribution facilities over which no previous jurisdictional transactions have been conducted.[13] In this instance, Block Island Wind will be interconnecting to a substation on Block Island that would not exist, but for the Town of New Shoreham Project statute which requires both Block Island Wind and BIPCO to be served from these facilities. By legislative intent, therefore, service to one cannot exist without the other. When the Block Island substation is constructed, the point of interconnection will clearly be to facilities built with the intent to serve a transmission function as they will be designed to simultaneously provide network transmission service to BIPCO. Indeed, neither the Block Island substation nor the bidirectional submarine cable between Block Island and the mainland will ever serve a distribution function.

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11 16 U.S.C. §§ 824d(a), -(c).

12 *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139, at 61,979 (1993).

13 *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 804, 808-09 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, at PP 710, 730 (2004). Block Island Wind has not requested QF status for its generating facility. If the generating facility were to be granted QF status, NEP's understanding is that the first-in-line rule would thereby be inapplicable. This understanding is based on discussions between NEP (and affiliates of NEP) and Commission Staff in other proceedings where the first-in-line rule was relevant. See, for example, page 3 of the transmittal letter for NEP's April 12, 2013 filing in Docket No. ER13-1279-000 of an interconnection agreement between NEP and Baltic Mill Enterprises.

III. Effective Date

NEP requests that the Commission accept the LGIA effective 61 days after the date of this filing, *i.e.*, September 23, 2014.

IV. Attachments

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	LGIA in clean format
Attachment B	Black-lined revisions showing the differences between the LGIA and the *pro forma* Large Generator Interconnection Agreement

V. Communications

Communications and correspondence regarding this filing should be addressed to the following individuals:

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and Director
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terry.schwennesen@nationalgrid.com

VI. Service

Copies of this filing have been served on Block Island Wind, Narragansett, BIPCO, ISO-NE, and the Rhode Island Public Utilities Commission.

VII. Conclusion

For these reasons, NEP requests that the Commission accept the LGIA effective September 23, 2014. Please contact the undersigned with any questions concerning this filing.

Respectfully submitted,

/s/ Kenneth G. Jaffe

Terry Schwennesen
Counsel for National Grid
40 Sylvan Road
Waltham, MA 02451

Kenneth G. Jaffe
Bradley R. Miliauskas
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The Atlantic Building
950 F Street, NW
Washington, DC 20004

Attorneys for National Grid USA

Attachment A

Original Service Agreement No. IA-NEP-26
New England Power Company
Large Generator Interconnection Agreement
With Deepwater Block Island Wind, LLC

LARGE GENERATOR INTERCONNECTION AGREEMENT

BY AND BETWEEN

DEEPWATER BLOCK ISLAND WIND, LLC

AND

NEW ENGLAND POWER COMPANY d/b/a NATIONAL GRID

LARGE GENERATOR INTERCONNECTION AGREEMENT

TABLE OF CONTENTS

THIS LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 30th day of June 2014, by and between Deepwater Block Island Wind, LLC, a company organized and existing under the laws of the State of Delaware ("Interconnection Customer" with a Large Generating Facility), and New England Power Company d/b/a National Grid, a company organized and existing under the laws of the Commonwealth of Massachusetts ("Interconnecting Transmission Owner"). Under this Agreement the Interconnection Customer and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator") is the central dispatching agency provided for under the Transmission Operating Agreement ("TOA") which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the ISO New England Inc. Transmission, Markets and Services Tariff (Tariff); and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and

WHEREAS, Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the generator interconnection process provided for in Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under Schedule 22. Capitalized terms in this Agreement or Schedule 22 that are not defined in this Agreement shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Transmission System.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Parties.

At-Risk Expenditure shall mean money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case shall have the meaning specified in Section 2.3 of the Large Generator Interconnection Procedures ("LGIP").

Base Case Data shall mean the Base Case power flow, short circuit, and stability data bases used for the Interconnection Studies by Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, but not be limited to, information that is confidential pursuant to the ISO New England Information Policy.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by the Commission or if filed unexecuted, upon the date specified by the Commission.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission Owner, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or any Affected System to which the New England Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Engineering & Procurement ("E&P") Agreement shall mean an agreement that authorizes the Interconnection Customer, Interconnecting Transmission Owner and any other Affected Party to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq.*

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner's Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner shall mean a Transmission Owner that owns, leases or otherwise possesses an interest in the portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Large Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by Interconnecting Transmission Owner from the Point of

Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer shall mean any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Generating Facility with the Administered Transmission System under the Standard Large Generator Interconnection Procedures.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request (a) shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System; (ii) increase the energy capability or capacity capability of an existing Generating Facility; (iii) make a Material Modification to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System; or (iv) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service shall mean the service provided by the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, the Interconnection Facilities Study and the Optional Interconnection Study described in the Standard Large Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement shall mean any of the following agreements: the Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, the Interconnection Facilities Study Agreement, and the Optional Interconnection Study Agreement attached to the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Large Generating Facility shall mean a Generating Facility having a maximum gross capability at or above zero degrees F of more than 20 MW.

Long Lead Time Generating Facility ("Long Lead Facility") shall mean a Generating Facility with an Interconnection Request for CNR Interconnection Service that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Section 3.2.3 of the LGIP.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Initial Synchronization Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; or (iv) except as provided in Section 3.2.3.4 of the LGIP, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6 of the LGIP, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Upgrades shall mean the additions, modifications, and upgrades to the New England Transmission System required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the Administered Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party shall mean the Interconnection Customer and Interconnecting Transmission Owner or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to Interconnecting Transmission Owner's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Administered Transmission System.

Queue Position shall mean the order of a valid request in the New England Control Area, relative to all other pending requests in the New England Control Area, that is established based upon the date and time of receipt of such request by the System Operator. Requests are comprised of Interconnection Requests, requests for Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. For purposes of this LGIA, references to a "higher-queued" Interconnection Request shall mean one that has been received by the System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as "lower-queued."

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property for which new interconnection is sought; (b) that the Interconnection Customer holds a valid written leasehold interest in the real property for which new interconnection is sought; (c) that the Interconnection Customer holds a valid written option to purchase or leasehold property for which new interconnection is sought; (d) that the Interconnection Customer holds a duly executed written contract to purchase or leasehold the real property for which new interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The Interconnection Customer and Interconnecting Transmission Owner, in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 **Effective Date**. This LGIA shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. Interconnecting Transmission Owner, shall promptly and jointly file this LGIA with the Commission upon execution in accordance with Section 11.3 of the LGIP and Article 3.1, if required.

2.2 Term of Agreement. This LGIA, subject to the provisions of Article 2.3, and by mutual agreement of the Parties, shall remain in effect for a period of twenty (20) years from the Commercial Operations Date and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by the Interconnection Customer, subject to continuing obligations of this LGIA and the Tariff, after giving the Interconnecting Transmission Owner ninety (90) Calendar Days advance written notice, or by Interconnecting Transmission Owner notifying the Commission after a Generating Facility retires pursuant to the Tariff, provided that if an Interconnection Customer exercises its right to terminate on ninety (90) Calendar Days, any reconnection would be treated as a new interconnection request; or this LGIA may be terminated by Interconnecting Transmission Owner by notifying the Commission after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Each Party may terminate this LGIA in accordance with Article 17. Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing, if applicable, with the Commission of a notice of termination of this LGIA, which notice has been accepted for filing by the Commission. Termination of the LGIA shall not supersede or alter any requirements for deactivation or retirement of a generating unit under ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

2.4 Termination Costs. If a Party elects to terminate this LGIA pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party(ies), as of the date of such Party's(ies') receipt of such notice of termination, that are the responsibility of such Party(ies) under this LGIA. In the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by the Commission:

2.4.1 With respect to any portion of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades to the extent covered by this LGIA, that have not yet been constructed or installed, the Interconnecting Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Interconnecting Transmission Owner shall deliver such material and equipment, and, if necessary, and to the extent possible, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Interconnecting Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, either (i) in the case of overpayment, Interconnecting Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by the Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts, or (ii) in the case of underpayment, Interconnection Customer shall promptly pay such amounts still due plus any costs, including penalties incurred by Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which the Interconnecting Transmission Owner has incurred expenses and has not been reimbursed by the Interconnection Customer.

2.4.2 Interconnecting Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Interconnecting Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, Interconnection Service shall terminate and, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Interconnecting Transmission Owner's Interconnection Facilities. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from a non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party(ies) pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

3.1 Filing. The Interconnecting Transmission Owner shall jointly file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required, in accordance with Section 11.3 of the LGIP. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the Interconnecting Transmission Owner with respect to such filing and to provide any information reasonably requested by the Interconnecting Transmission Owner needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

4.1 Reserved.

4.2 Provision of Service. Interconnecting Transmission Owner shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the LGIA and Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

4.5 Reserved.

4.6 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.4. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall specify the In-Service Date, Initial Synchronization Date, and Commercial Operation Date as specified in the Interconnection Request or as subsequently revised pursuant to Section 4.4 of the LGIP; and select either Standard Option or Alternate Option set forth below for completion of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as set forth in Appendix A, and such dates and selected option shall be set forth in Appendix B (Milestones). In accordance with Section 8 of the LGIP and unless otherwise mutually agreed, the Alternate Option is not an available option if the Interconnection Customer waived the Interconnection Facilities Study.

5.1.1 Standard Option. The Interconnecting Transmission Owner shall design, procure, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B (Milestones). The Interconnecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Interconnecting Transmission Owner reasonably expects that it will not be able to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the specified dates, the Interconnecting Transmission Owner shall promptly provide written notice to the Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities by the designated dates.

If Interconnecting Transmission Owner subsequently fails to complete Interconnecting Transmission Owner's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B (Milestones); Interconnecting Transmission Owner shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable System Operator refuses to grant clearances to install equipment.

5.1.3 **Option to Build**. If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. The System Operator, Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by System Operator in accordance with applicable codes of conduct and confidentiality requirements must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A to the LGIA. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 **Negotiated Option**. If the Interconnection Customer elects not to exercise its option under Article 5.1.3 (Option to Build), Interconnection Customer shall so notify Interconnecting Transmission Owner within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection

Customer) pursuant to which Interconnecting Transmission Owner is responsible for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Interconnecting Transmission Owner shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades pursuant to 5.1.1 (Standard Option).

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Interconnecting Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Interconnecting Transmission Owner would be subject in the engineering, procurement or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Interconnecting Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Interconnecting Transmission Owner a schedule for construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Interconnecting Transmission Owner;

(5) at any time during construction, Interconnecting Transmission Owner shall have the right to gain unrestricted access to the Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Interconnecting Transmission Owner, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the Interconnecting Transmission Owner for claims arising from the Interconnection Customer's construction of Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 (Indemnity);

(8) the Interconnection Customer shall transfer control of Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades to the Interconnecting Transmission Owner;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades to Interconnecting Transmission Owner;

(10) Interconnecting Transmission Owner shall approve and accept for operation and maintenance the Interconnecting Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Interconnecting Transmission Owner “as built” drawings, information, and any other documents that are reasonably required by Interconnecting Transmission Owner to assure that the Interconnection Facilities and Stand Alone Network

Upgrades are built to the standards and specifications required by Interconnecting Transmission Owner.

5.3 **Liquidated Damages**. The actual damages to the Interconnection Customer, in the event the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Interconnecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Interconnecting Transmission Owner to the Interconnection Customer in the event that Interconnecting Transmission Owner does not complete any portion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Interconnecting Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which the Interconnecting Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Interconnecting Transmission Owner to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Interconnecting Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless the Interconnection Customer would have been able to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Interconnecting Transmission Owner's delay; (2) the Interconnecting Transmission Owner's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with the Interconnecting Transmission Owner or any cause beyond Interconnecting Transmission Owner's reasonable control or reasonable ability to cure, including, but not limited to, actions by the System Operator that cause delays and/or delays in licensing, permitting or consents where the Interconnecting Transmission Owner has pursued such licenses, permits or consents in good faith; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers**. If a Power System Stabilizer is required to be installed on the Large Generating Facility for the purpose of maintaining system stability, the Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the System Operator and Interconnecting Transmission Owner, and consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator and Interconnecting Transmission Owner reserve the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the System Operator and Interconnecting Transmission Owner, or their designated representative. The requirements of this paragraph shall not apply to non-synchronous power production equipment.

5.5 **Equipment Procurement**. If responsibility for construction of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by the Interconnecting Transmission Owner, then the Interconnecting Transmission Owner shall commence design of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The Interconnecting Transmission Owner has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 The Interconnecting Transmission Owner has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B (Milestones); and

5.5.3 The Interconnection Customer has provided security to the Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.6 **Construction Commencement**. The Interconnecting Transmission Owner shall commence construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades;

5.6.3 The Interconnecting Transmission Owner has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B (Milestones); and

5.6.4 The Interconnection Customer has provided security to Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.7 Work Progress. The Interconnection Customer and the Interconnecting Transmission Owner shall keep each Party informed, by written quarterly progress reports, as to the progress of their respective design, procurement and construction efforts in order to meet the dates specified in Appendix B (Milestones). Any Party may also, at any other time, request a written progress report from the other Parties. If, at any time, the Interconnection Customer determines that the completion of the Interconnecting Transmission Owner's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer will provide written notice to the Interconnecting Transmission Owner of such later date upon which the completion of the Interconnecting Transmission Owner's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the New England Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, the Interconnecting Transmission Owner shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. System Operator and Interconnecting Transmission Owner shall permit Interconnection Customer to operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ("ICIF"). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.10.1 Large Generating Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Interconnecting Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Interconnecting Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Interconnecting Transmission Owner's Review. Interconnecting Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Interconnecting Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Interconnecting Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facilities. The Interconnection Customer shall provide Interconnecting Transmission Owner specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Interconnecting Transmission Owner's Interconnection Facilities Construction. The Interconnecting Transmission Owner's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnecting Transmission Owner shall deliver to the Interconnection Customer the following "as-built" drawings, information and documents for the Interconnecting Transmission Owner's Interconnection Facilities. The appropriate drawings and relay diagrams shall be included in Appendix A of this LGIA.

The System Operator will obtain operational control of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities pursuant to the TOA.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at the incremental cost to another Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents if allowed under the applicable agency agreement, that are necessary to enable the Access Party solely to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Administered Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the New England Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Interconnecting Transmission Owner, the

Interconnecting Transmission Owner shall at Interconnection Customer's expense use Reasonable Efforts, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property. Notwithstanding the foregoing, the Interconnecting Transmission Owner shall not be obligated to exercise eminent domain authority in a manner inconsistent with Applicable Laws and Regulations or when an Interconnection Customer is authorized under Applicable Laws and Regulations to exercise eminent domain on its own behalf.

5.14 **Permits.** Interconnecting Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Interconnecting Transmission Owner shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Interconnecting Transmission Owner's own, or an Affiliate's generation.

5.15 **Early Construction of Base Case Facilities.** Interconnection Customer may request Interconnecting Transmission Owner to construct, and Interconnecting Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Administered Transmission System, which are included in the Base Case of the Facilities Study for the Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date. The Interconnection Customer shall reimburse the Interconnecting Transmission Owner for all costs incurred related to early construction to the extent such costs are not recovered from other Interconnection Customers included in the base case.

5.16 **Suspension.** Interconnection Customer reserves the right, upon written notice to Interconnecting Transmission Owner and System Operator, to suspend at any time all work by Interconnecting Transmission Owner associated with the construction and installation of Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades required under this

LGIA with the condition that the New England Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and the System Operator's and Interconnecting Transmission Owner's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Interconnecting Transmission Owner (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the New England Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Interconnecting Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Interconnecting Transmission Owner shall obtain Interconnection Customer's authorization to do so. Interconnecting Transmission Owner shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Interconnecting Transmission Owner required under this LGIA pursuant to this Article 5.16, and has not requested Interconnecting Transmission Owner to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Interconnecting Transmission Owner and System Operator, if no effective date is specified. A suspension under this Article 5.16 does not automatically permit an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date. A request for extension of such dates is subject to Section 4.4.5 of the LGIP. Notwithstanding the extensions permitted under Section 4.4.5 of the LGIP, the three-year period shall in no way result in an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date that exceeds seven (7) years from the date of the Interconnection Request; otherwise, this LGIA shall be deemed terminated.

5.17 Taxes.

5.17.1 Payments Not Taxable. The Parties intend that all payments or property transfers made by any Party for the installation of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the New England Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Interconnecting Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Interconnecting Transmission Owner's request, Interconnection Customer shall provide Interconnecting Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Interconnecting Transmission Owner represents and covenants that the cost of the Interconnecting Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon Interconnecting Transmission Owner. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Interconnecting Transmission Owner from the cost consequences of any current tax liability imposed against

Interconnecting Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Interconnecting Transmission Owner.

The Interconnecting Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Interconnecting Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Interconnecting Transmission Owner to report payments or property as income subject to taxation; provided, however, that Interconnecting Transmission Owner may require Interconnection Customer to provide security, in a form reasonably acceptable to Interconnecting Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Interconnecting Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Interconnecting Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period, and the applicable statute of limitation, as it may be extended by the Interconnecting Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Interconnecting Transmission Owner, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Interconnecting Transmission Owner ("Current

Taxes") on the excess of (a) the gross income realized by Interconnecting Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Interconnecting Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).For this purpose, (i) Current Taxes shall be computed based on Interconnecting Transmission Owner composite federal and state tax rates at the time the payments or property transfers are received and Interconnecting Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Interconnecting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Interconnecting Transmission Owner current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Interconnecting Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Interconnecting Transmission Owner under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Interconnecting Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Interconnecting Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Interconnecting Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 **Subsequent Taxable Events**. If, within ten (10) years from the date on which the relevant Interconnecting Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenant contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Interconnecting Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Interconnecting Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 **Contests**. In the event any Governmental Authority determines that Interconnecting Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Interconnecting Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Interconnecting Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Interconnecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Interconnecting Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Interconnecting Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Interconnecting Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Interconnecting Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Interconnecting Transmission Owner for the tax at issue in the contest.

5.17.8 Refund. In the event that (a) a private letter ruling is issued to Interconnecting Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Interconnecting Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not taxable to Interconnecting Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Interconnecting Transmission Owner are not subject to federal income tax, or (d) if Interconnecting Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by

Interconnection Customer to Interconnecting Transmission Owner pursuant to this LGIA, Interconnecting Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Interconnecting Transmission Owner for such taxes which Interconnecting Transmission Owner did not submit to the taxing authority, interest calculated in accordance with the methodology set forth in the Commission's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Interconnecting Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Interconnecting Transmission Owner, any refund or credit Interconnecting Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Interconnecting Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Interconnecting Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Interconnecting Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Interconnecting Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Interconnecting Transmission Owner's Interconnection Facilities.

The intent of this provision is to leave Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network

Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Interconnecting Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Interconnecting Transmission Owner for which Interconnection Customer may be required to reimburse Interconnecting Transmission Owner under the terms of this LGIA. Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, Interconnecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Interconnecting Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Interconnecting Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Interconnecting Transmission Owner.

5.18 Tax Status. Each Party shall cooperate with the others to maintain the other Party's(ies') tax status. Nothing in this LGIA is intended to adversely affect any Interconnecting Transmission Owner's tax-exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Interconnection Customer or Interconnecting Transmission Owner may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, the facilities of any Affected Parties, or the New England Transmission System, that Party shall provide to the other Parties and any Affected Party: (i) sufficient information regarding such modification so that the other Party(ies) may evaluate the potential impact of such modification prior to commencement of the work; and (ii) such information as may be required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party(ies) at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed. Notwithstanding the foregoing, no Party shall be obligated to proceed with a modification that would constitute a Material Modification and therefore require an Interconnection Request under the LGIP, except as provided under and pursuant to the LGIP.

In the case of Large Generating Facility or Interconnection Customer's Interconnection Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Interconnecting Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Interconnecting Transmission Owner makes to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System to facilitate the interconnection of a third party to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System, or to provide transmission service to a third party under the Tariff, except as provided for under the Tariff or any other applicable tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, the Interconnecting Transmission Owner shall test Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Interconnection Customer and Interconnecting Transmission Owner shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, as may be necessary to ensure the continued interconnection of the Large Generating Facility to the Administered Transmission System in a safe and reliable manner. The Interconnection Customer and Interconnecting Transmission Owner each shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's(ies') facilities, at the requesting Party's expense, as may be in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator shall also have the right to require reasonable additional testing of the other Party's (ies') facilities in accordance with the

ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

6.3 **Right to Observe Testing.** Each Party shall notify the System Operator and other Party(ies) in advance of its performance of tests of its Interconnection Facilities. The other Party(ies) has the right, at its own expense, to observe such testing.

6.4 **Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's(ies') tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's(ies') System Protection Facilities and other protective equipment; and (iii) review the other Party's(ies') maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Each Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be governed by Article 22.

ARTICLE 7. METERING

7.1 General. Each Party shall comply with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding metering. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment. Unless the System Operator otherwise agrees, the Interconnection Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Tariff and to communicate the information to the System Operator. Unless otherwise agreed, such equipment shall remain the property of the Interconnecting Transmission Owner.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Interconnecting Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Interconnecting Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Interconnecting Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards and the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.4 Testing of Metering Equipment. Interconnecting Transmission Owner shall inspect and test all Interconnecting Transmission Owner-owned Metering Equipment upon installation and thereafter as specified in the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than the values specified within ISO New England Operating Documents, or successor documents, from the measurement made by the standard meter used in the test, the Interconnecting Transmission Owner shall adjust the measurements, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.5 **Metering Data.** At Interconnection Customer's expense, metered data shall be telemetered to one or more locations designated by System Operator and Interconnecting Transmission Owner. The hourly integrated metering, established in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, used to transmit Megawatt hour ("MWh") per hour data by electronic means and the Watt-hour meters equipped with kilowatt-hour ("kwh") or MWh registers to be read at month's end shall be the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection. Instantaneous metering is required for all Generators in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 8. COMMUNICATIONS

8.1 **Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with the System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.2 **Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer or Interconnecting Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by System Operator and Interconnecting Transmission Owner through use of a dedicated point-to-point data circuit(s). The communication protocol for the data circuit(s) shall be specified by System Operator and Interconnecting Transmission Owner. All information required by the ISO New England

Operating Documents, or successor documents, must be telemetered directly to the location(s) specified by System Operator and Interconnecting Transmission Owner.

Each Party will promptly advise the other Party(ies) if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party(ies). The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from an Intermittent Power Resource.** The Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall provide meteorological and forced outage data to the System Operator to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The Interconnection Customer with an Intermittent Power Resource having wind as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with an Intermittent Power Resource having solar as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The System Operator and Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power product forecast. The Interconnection Customer whose Generating Facility is an Intermittent Power Resource also shall submit data to the System Operator regarding all forced outages to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the System Operator, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Intermittent Power Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the System Operator. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with applicable provisions of ISO New England Operating Documents, Reliability Standards, or successor documents, regarding operations. Each Party shall provide to the other Party(ies) all information that may reasonably be required by the other Party(ies) to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. Before Initial Synchronization Date, the Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner in writing in accordance with ISO New England Operating Documents, Reliability Standards, or successor documents. If the Interconnection Customer elects to have the Large Generating Facility dispatched and operated from a remote Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs and ISO New England Operating Documents, Reliability Standards, or successor documents, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area for dispatch and operations.

9.3 Interconnecting Transmission Owner and System Operator Obligations. Interconnecting Transmission Owner and System Operator shall cause the Interconnecting Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Reliability Standards, or successor documents. Interconnecting Transmission Owner or System Operator may provide operating instructions to Interconnection Customer consistent with this LGIA, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Interconnecting Transmission Owner's and System Operator's operating protocols and procedures as they may change from time to time. Interconnecting Transmission Owner and

System Operator will consider changes to their operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.5 Start-Up and Synchronization. The Interconnection Customer is responsible for the proper start-up and synchronization of the Large Generating Facility to the New England Transmission System in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility and all generating units comprising the Large Generating Facility, as applicable, to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis and in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The requirements of this paragraph shall not apply to wind generators.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized the Large Generating Facility to the New England Transmission System, Interconnection Customer shall operate the Large Generating Facility at the direction of System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding voltage schedules in accordance with such requirements.

9.6.2.1 Voltage Regulators. The Interconnection Customer must keep and maintain a voltage regulator on all generating units comprising a Large Generating Facility in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. All Interconnection Customers that have, or are required to have, automatic voltage regulation shall normally operate the Large Generating Facility with its voltage regulators in automatic operation.

It is the responsibility of the Interconnection Customer to maintain the voltage regulator in good operating condition and promptly report to the System Operator and Interconnecting Transmission Owner any problems that could cause interference with its proper operation.

9.6.2.2 Governor Control. The Interconnection Customer is obligated to provide and maintain a functioning governor on all generating units comprising the Large Generating Facility in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6.2.3 System Protection. The Interconnection Customer shall install and maintain protection systems in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6.3 Payment for Reactive Power.

Interconnection Customers shall be compensated for Reactive Power service in accordance with Schedule 2 of the Section II of the Tariff.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. The System Operator shall have the authority to coordinate facility outages in accordance with the ISO New England

Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's(ies') facilities as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.1.2 Outage Schedules. Outage scheduling, and any related compensation, shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.2 Interruption of Service. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the System Operator or Interconnecting Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect System Operator's or Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.

9.7.3 Under-Frequency and Over Frequency Conditions. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with System Operator and Interconnecting Transmission Owner in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall install at Interconnection Customer's expense, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, any System Protection Facilities that may be required on the Interconnecting Transmission Owner Interconnection Facilities or the New England Transmission System as a result of the interconnection of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.4 Each Party's protective relay design shall allow for tests required in Article 6.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.5 Requirements for Protection. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and compliance with Good Utility Practice , Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the New England Transmission System not otherwise isolated by Interconnecting Transmission

Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the New England Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the New England Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the New England Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. A Party's facilities shall not cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party(ies) with a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Administered Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Interconnecting Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Commission for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the New England Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 10. MAINTENANCE

10.1 Interconnecting Transmission Owner and Customer Obligations. Interconnecting Transmission Owner and Interconnection Customer shall each maintain that portion of its respective facilities that are part of the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

10.2 **Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Interconnecting Transmission Owner's Interconnection Facilities, Stand Alone Network Upgrades, Network Upgrades and Distribution Upgrades.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 **Interconnection Customer's Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at its sole expense.

11.2 **Interconnecting Transmission Owner's Interconnection Facilities.** Interconnecting Transmission Owner shall design, procure, construct, install, own and/or control the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at the sole expense of the Interconnection Customer.

11.3 **Network Upgrades and Distribution Upgrades.** Interconnecting Transmission Owner shall design, procure, construct, install, and own the Network Upgrades, and to the extent provided by Article 5.1, Stand Alone Network Upgrades, and Distribution Upgrades described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades). The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Interconnecting Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Cost Allocation; Compensation; Rights; Affected Systems

11.4.1 Cost Allocation. Cost allocation of Generator Interconnection Related Upgrades shall be in accordance with Schedule 11 of Section II of the Tariff.

11.4.2 Compensation. Any compensation due to the Interconnection Customer for increases in transfer capability to the PTF resulting from its Generator Interconnection Related Upgrade shall be determined in accordance with Sections II and III of the Tariff.

11.4.3 Rights. Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades.

11.4.4 Special Provisions for Affected Systems. The Interconnection Customer shall enter into separate related facilities agreements to address any upgrades to the Affected System(s) that are necessary for safe and reliable interconnection of the Interconnection Customer's Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of an Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Interconnecting Transmission Owner a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Interconnecting Transmission Owner in accordance with Section 7 of Schedule 11 of the Tariff. In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Interconnecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.6 **Interconnection Customer Compensation.** If System Operator or Interconnecting Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.4.1 of this LGIA, Interconnection Customer shall be compensated pursuant to the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

11.6.1 **Interconnection Customer Compensation for Actions During Emergency Condition.** Interconnection Customer shall be compensated for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the New England Transmission System during an Emergency Condition in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 12. INVOICE

12.1 **General.** Each Party shall submit to the other Party(ies), on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party(ies) under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 **Final Invoice.** Within six months after completion of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades, Interconnecting Transmission Owner shall provide an invoice of the final cost of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnecting Transmission Owner shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Interconnection Customer shall pay to Interconnecting Transmission Owner any amount by which the actual payment by Interconnection Customer for estimated costs falls short of the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by any Party will not constitute a waiver of any rights or claims the other Party(ies) may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Interconnecting Transmission Owner and Interconnection Customer, Interconnecting Transmission Owner shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Interconnecting Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Interconnecting Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in the Commission's Regulations at 18 CFR § 35.19a(a)(2)(iii).

ARTICLE 13. EMERGENCIES

13.1 Obligations. Each Party shall comply with the Emergency Condition procedures of the System Operator in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

13.2 Notice. Interconnecting Transmission Owner or System Operator as applicable shall notify Interconnection Customer and System Operator or Interconnecting Transmission Owner as applicable, promptly when it becomes aware of an Emergency Condition that affects the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Interconnecting Transmission Owner and System Operator promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Interconnecting Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.3 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Interconnecting Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by the Interconnecting Transmission Owner or otherwise regarding the New England Transmission System.

13.4 System Operator's and Interconnecting Transmission Owner's Authority.

13.4.1 General. System Operator or Interconnecting Transmission Owner may take whatever actions or inactions with regard to the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the New England Transmission System or Interconnecting Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. System Operator and Interconnecting Transmission Owner may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.4.2; directing the Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of System Operator's and Interconnecting Transmission Owner's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.4.2 Reduction and Disconnection. System Operator and Interconnecting Transmission Owner may reduce Interconnection Service or disconnect the Large Generating Facility or the Interconnection Customer's Interconnection Facilities when such reduction or disconnection is necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. These rights are separate and distinct from any right of curtailment of the System Operator and Interconnecting Transmission Owner pursuant to the Tariff. When the System Operator and Interconnecting Transmission Owner can schedule the reduction or disconnection in advance, System Operator and Interconnecting Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. System Operator and Interconnecting Transmission Owner shall coordinate with the Interconnection Customer in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the System Operator and Interconnecting Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the New England Transmission System to their normal operating state as soon as practicable in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

13.5 Interconnection Customer Authority. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents and the LGIA and the LGIP, the Interconnection Customer may take whatever actions or inactions with regard to the Large Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities. System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.6 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, a Party shall not be liable to another Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended. To the extent that a condition arises that could result in Interconnection Customer's inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978, the Parties shall engage in good faith negotiations to address the condition so that such result will not occur and so that this LGIA can be performed.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by a Party to another Party and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F (Addresses for Delivery of Notices and Billings).

A Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another Party and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party(ies) in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 A Party shall not be considered to be in Default with respect to any obligation hereunder (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party(ies) in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default.

17.1.1 General. No Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party(ies). Upon a Breach, the non-Breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the non-Breaching Party(ies) shall have the right to terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this LGIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which they are entitled at law or in equity. The provisions of this Article will survive termination of this LGIA.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

Notwithstanding any other provision of this Agreement, the liability, indemnification and insurance provisions of the Transmission Operating Agreement ("TOA") or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner and the liability, indemnification and insurance provisions of the Tariff apply to the relationship between the Interconnecting Transmission Owner and the Interconnection Customer.

18.1 Indemnity. Each Party shall at all times indemnify, defend, and save the other Party(ies) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's(ies') action or inactions of their obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by an indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in which event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall a Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 **Insurance.** The Interconnecting Transmission Owner and the Interconnection Customer shall, at their own expense, maintain in force throughout the period of this LGIA, and until released by the other Party(ies), the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death, and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party(ies), its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program, provided that such Party's senior secured debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article, it shall notify the other Party(ies) that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

ARTICLE 19. ASSIGNMENT

19.1 **Assignment.** This LGIA may be assigned by any Party only with the written consent of the other Parties; provided that the Parties may assign this LGIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further that the Interconnection Customer shall have the right to assign this LGIA, without the consent of the Interconnecting Transmission Owner or System Operator, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Interconnection Customer will promptly notify the Interconnecting Transmission Owner and System Operator of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Interconnecting Transmission Owner and System Operator of the date and particulars of any such exercise of assignment right(s), including providing the Interconnecting Transmission Owner with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 **Severability.** If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Interconnecting Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 **Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 **Confidentiality.** Confidential Information shall include, without limitation, all information governed by the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by a Party, the other Party(ies) shall provide, in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party(ies) that it no longer is confidential.

22.1.3 Release of Confidential Information. A Party shall not release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party(ies). The disclosure by each Party to the other Party(ies) of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. By providing Confidential Information, a Party does not make any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, a Party does not obligate itself to provide any particular information or Confidential Information to the other Party(ies) nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party(ies) under this LGIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other

Party(ies) with prompt notice of such request(s) or requirement(s) so that the other Party(ies) may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party(ies), use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party(ies)) or return to the other Party(ies), without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party(ies).

22.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's(ies') Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party(ies) shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Parties shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to the Commission, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR. section 1b.20, if the Commission or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to the Commission or its staff, within the time provided for in the request for information. In providing the information to the Commission or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this LGIA prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Party(ies) to the LGIA when it is notified by the Commission or its staff that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party(ies) to any person not employed or retained by the other Party(ies), except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party(ies), such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party(ies) in writing of the information it claims is confidential. Prior to any disclosures of the other Parties' Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party(ies) in writing and agrees to assert confidentiality and cooperate with the other Party(ies) in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Party(ies), first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party(ies). The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four (24) hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party(ies) copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 **Information Acquisition.** Subject to any applicable confidentiality restrictions, including, but not limited to, codes of conduct, each Party shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by Interconnecting Transmission Owner.** The initial information submission by Interconnecting Transmission Owner shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date and shall include information necessary to allow the Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise mutually agreed to by the Parties. On a monthly basis Interconnecting Transmission Owner shall provide Interconnection Customer a status report on the construction and installation of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 **Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Interconnecting Transmission Owner and System Operator for the Interconnection Feasibility Study, Interconnection System Impact Study and Interconnection Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Interconnecting Transmission Owner standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is different from what was originally provided to Interconnecting Transmission Owner pursuant to the Interconnection Study Agreement between Interconnecting Transmission Owner and Interconnection Customer, then the Interconnecting Transmission Owner will review it and conduct appropriate studies, as needed, at the Interconnection Customer's cost, to determine the impact on the New England Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 **Information Supplementation.** Prior to the Commercial Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information and "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to the Interconnecting Transmission Owner for each individual generating unit in a station.

The Interconnection Customer shall provide the Interconnecting Transmission Owner with any information changes due to proposed equipment replacement, repair, or adjustment. Interconnecting Transmission Owner shall provide the Interconnection Customer with any information changes due to proposed equipment replacement, repair or adjustment in the directly connected substation or any adjacent Interconnecting Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information in accordance with Article 5.19 of this Agreement.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Party(ies) to: (i) verify the costs incurred by the disclosing Party for which the other Party(ies) are responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party(ies) when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory Breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party(ies), to audit at its own expense the other Party's(ies') accounts and records pertaining to a Party's performance or a Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's(ies') costs, calculation of invoiced amounts, the efforts to allocate responsibility for the provision of reactive support to the New England Transmission System, the efforts to allocate responsibility for interruption or reduction of generation on the New England Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four (24) months following Interconnecting Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four (24) months after the event for which the audit is sought.

25.5 **Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party(ies) together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 **General.** Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

26.2 **Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party(ies) for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 **No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 **Submission.** In the event a Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party(ies) with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party(ies). In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's(ies') receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 **External Arbitration Procedures.** Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The arbitrators chosen by the Parties shall select a third member who shall chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable Commission regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail

27.3 **Arbitration Decisions.** Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 **Costs.** Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) a pro rata share of the cost of a single arbitrator chosen by the Parties.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 **General.** Each Party makes the following representations, warranties and covenants:

28.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 **Authority.** Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict.** The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 **Consent and Approval.** Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

ARTICLE 29. [OMITTED]

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect. This LGIA and the rights and obligations hereof shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix of this LGIA, or such Section of the LGIP or such Appendix of the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, “from” means “from and including”, “to” means “to but excluding” and “through” means “through and including”.

30.4 **Entire Agreement.** Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, this LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. Except for the ISO New England Operating Documents, Applicable Reliability Standards, any applicable tariffs, related facilities agreements, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party’s compliance with its obligations under this LGIA.

30.5 **No Third Party Beneficiaries.** This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 **Waiver.** The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this LGIA. Termination or Default of this LGIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer’s legal rights to obtain an interconnection from the Interconnecting Transmission Owner. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Consistent with Section 11.3 of the LGIP, Interconnecting Transmission Owner shall have the right to make unilateral filings with the Commission to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Parties and to participate fully in any proceeding before the Commission in which such modifications may be considered. In the event of disagreement on terms and conditions of the LGIA related to the costs of upgrades to such Interconnecting Transmission Owner's transmission facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of Interconnecting Transmission Owner, and any provisions related to physical impacts of the interconnection on Interconnecting Transmission Owner's transmission facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to Interconnecting Transmission Owner's position on such terms and conditions. Nothing in this LGIA shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

IN WITNESS WHEREOF, the Parties have executed this LGIA in triplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

New England Power Company (Interconnecting Transmission Owner)

By: Will L Malee

William L. Malee

Title: Director, Transmission Commercial & Authorized Representative

Date: 16 July 2014

Deepwater Block Island Wind, LLC (Interconnection Customer)

By:____________________________

Title:

Date:

IN WITNESS WHEREOF, the Parties have executed this LGIA in triplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

New England Power Company (Interconnecting Transmission Owner)

By:________________________________

William L. Malee

Title: Director, Transmission Commercial & Authorized Representative

Date:

Deepwater Block Island Wind, LLC (Interconnection Customer)

By:________________________________

Title: CEO

Date: 7/16/14

APPENDICES TO LGIA

APPENDIX A TO LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

The Interconnection Facilities, Network Upgrades and Distribution Upgrades discussed below will be engineered, designed, constructed, owned, and maintained by a combination of the Interconnecting Transmission Owner, Interconnecting Transmission Owner's Affiliate: The Narragansett Electric Company ("TNECO"), and the Interconnection Customer, as specified below. Any reference to "Affiliate" below is specifically a reference to TNECO. It is acknowledged that the Interconnecting Transmission Owner will be responsible for coordinating with Interconnecting Transmission Owner's Affiliate as necessary to meet its obligations under this Agreement. It is further acknowledged by the Parties that Interconnecting Transmission Owner's Affiliate will own and maintain certain facilities identified under this Agreement, (hereafter, the "Interconnecting Transmission Owner's Affiliate Interconnection Facilities").

1. Interconnection Facilities:

a. **Point of Interconnection and Point of Change of Ownership**.

The Point of Interconnection shall be the "Delivery Point" as defined in the Power Purchase Agreement executed between Interconnecting Transmission Owner's Affiliate and Interconnection Customer on June 30, 2010, as the same may be amended and/or restated from time to time (the "Power Purchase Agreement"), which shall be the point at which the Interconnection Facilities connect to the low voltage side of Interconnecting Transmission Owner's Affiliate's substation, which is to be constructed on Block Island ("Block Island Substation").

The Point of Change of Ownership shall be the point at which the terrestrial cable, which shall be owned by Interconnecting Transmission Owner's Affiliate, shall terminate in Interconnection Customer's transition vault, located at Block Island Town Beach on Block Island, and shall be spliced with Interconnection Customer's submarine cable.

The metering point shall be located at the Point of Interconnection.

The Point of Interconnection, the Point of Change of Ownership and the metering point are shown in Appendix A-1, which drawing is attached hereto and made part hereof. This is a preliminary drawing for the purposes of illustrating the general arrangement of the interconnection. Additional details will be established in the Protection Philosophy to be established by the Parties.

b. **Interconnection Customer's Interconnection Facilities (including metering equipment)**.

The Interconnection Customer shall design to Interconnecting Transmission Owner's specifications, construct, own, operate, and maintain a 34.5kV undersea cable system from the wind farm in Block Island Sound to Block Island Town Beach, including the splices to the Interconnecting Transmission Owner's Affiliate's portions of the underground power cable, fiber optic cables, and neutral/ground continuity conductor in the transition vault at the beach, and certain data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment, as needed, located within a separate building in the Block Island substation (the "Interconnection Customer's Control Building"), as shown in the one-line diagram attached as Appendix A-1 and the general arrangement diagram attached as Appendix A-2.

Upon notification to Interconnecting Transmission Owner's Affiliate's control room, Interconnecting Transmission Owner's Affiliate shall allow Interconnection Customer (or an independent Person mutually acceptable to the Parties) access to the Block Island Substation for the purpose of facilitating Interconnection Customer's execution of its rights and obligations as set forth in Section 4.7 of the Power Purchase Agreement, including but not limited to the inspection, testing, calibration and audit of Interconnection Customer's revenue meter. Interconnection Customer shall have the right to install an additional check meter.

The Parties agree that Interconnection Customer's cost responsibility for the Direct Assignment Facilities, described in Section 4(A) of Appendix C to this LGIA, shall satisfy all of the Interconnection Customer's obligations to engineer, procure, provide, construct install, own, keep, operate or maintain any equipment, systems, rights of use, licenses, rights of way and easements in connection with this agreement, including but not limited to those obligations set forth in Sections 5.13, 5.19, 6.1, 8.2, 9.4, 9.7.4, 9.7.5, 10.2 and Appendix C.3.B of the LGIA. Direct Assignment Facilities shall have the meaning set forth in the Tariff.

c. **Interconnecting Transmission Owner's Interconnection Facilities (including metering equipment)**.

The Interconnecting Transmission Owner's Affiliate shall design, construct, own, operate and maintain the following equipment, at Interconnection Customer's expense, which collectively constitute the Interconnecting Transmission Owner's Affiliate Interconnection Facilities, i.e. the Direct Assignment Facilities: (1) a 34.5kV breaker and associated substation equipment as shown in Appendix A-1 and in Appendix A-2, (2) a 34.5kV grounding transformer, (3) an 34.5kV overhead circuit across the property upon which the substation is to be located, and (4) an underground cable system along a public way from the substation property to the Interconnection Customer's transition vault to be located at the Block Island Town Beach.

The Direct Assignment Facilities constitute all of Interconnecting Transmission Owner's Affiliate Interconnection Facilities.

The Interconnecting Transmission Owner will not design, construct, own, operate and maintain any equipment.

2. Network Upgrades:

a. **Stand Alone Network Upgrades**. None.

b. **Other Network Upgrades**. None.

3. Distribution Upgrades. None

4. Affected System Upgrades. None.

5. Contingency Upgrades List:

a. Long Lead Facility-Related Upgrades. Not Applicable.

The Interconnection Customer's Large Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

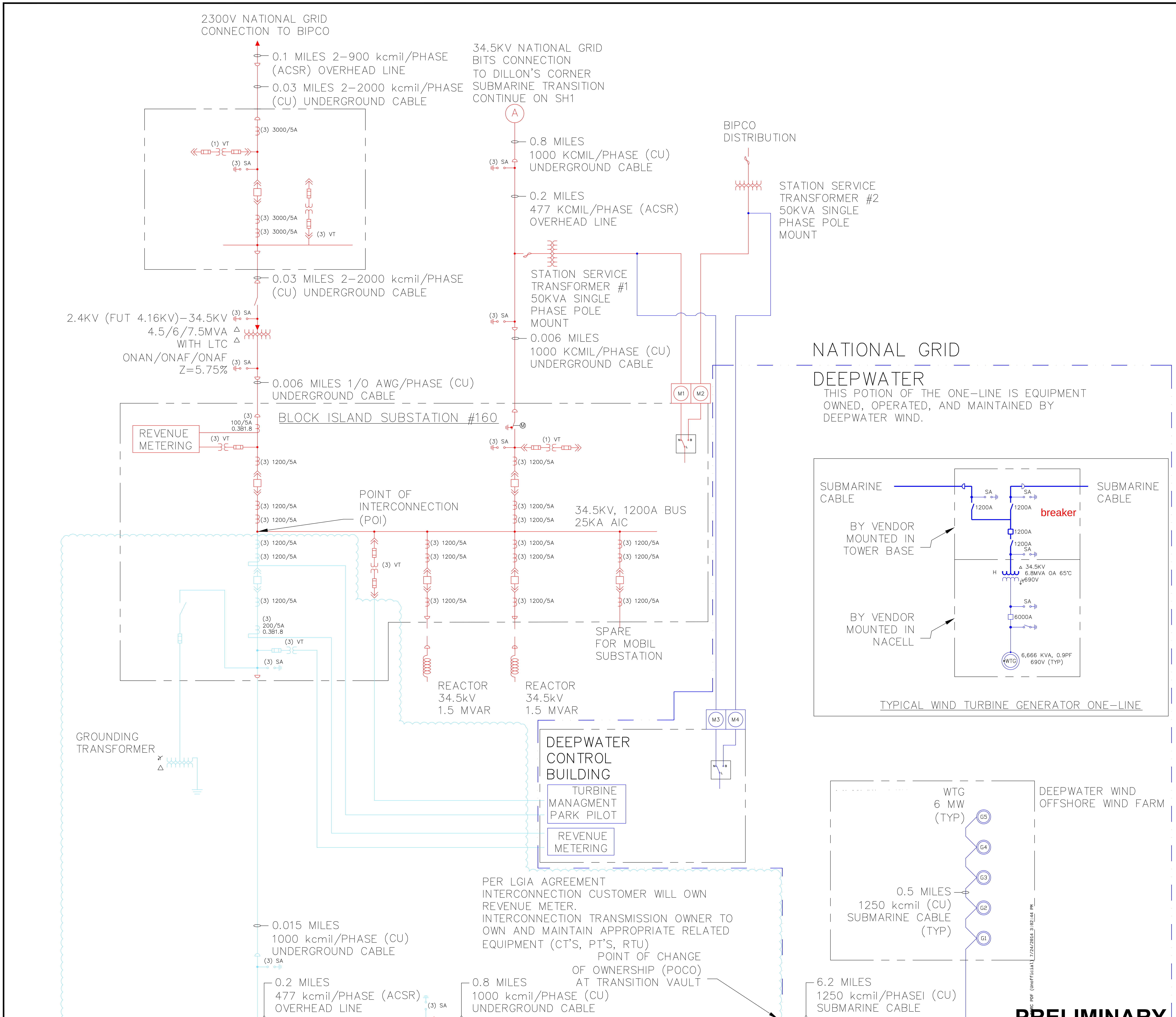
None

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this LGIA in accordance with Article 17.1, and the System Operator will initiate all necessary steps to terminate this LGIA, in accordance with Article 2.3.

b. Other Contingency Upgrades. None.

6. Post-Forward Capacity Auction Re-study Upgrade Obligations. To be determined

APPENDIX A-1 TO LGIA: ONE-LINE DIAGRAM



P:\313194 - Deepwater 2012 Project\Block Island BITS\Drawings\313194-E-101-SH2.dwg Oct 30, 2013 - 10:13AM MUR65313

Notes

NOTES

1. "DIRECT ASSIGNMENT FACILITIES" DESCRIBES THE EQUIPMENT THAT IS GOING TO BE INSTALLED, OPERATED, AND MAINTAINED BY NATIONAL GRID BY CONTRACT FOR THE BLOCK ISLAND WIND FARM.

Legend

TRANSFORMER
△ = DELTA CONNECTION
Y = WYE CONNECTION
Y = WYE GROUNDED CONNECTION

89L1B
1200A
CIRCUIT SWITCHER
89L1B = DEVICE NAME
1200A = RATING

(3) VT
14.4KV–120V
VOLTAGE TRANSFORMER (VT)
(3) = QUANTITY
14.4KV–120V = RATIO

(3)
400/5A
C400 MR
CURRENT TRANSFORMER (CT)
(3) = QUANTITY
400/5A = RATIO
C400 MR = CLASS, MULTI RATIO

F1
1200A
MEDIUM VOLTAGE, DRAWOUT TYPE, METAL CLAD AIR CIRCUIT BREAKER
F1 = BREAKER NAME
1200A = TRIP RATING

MEDIUM VOLTAGE DRAWOUT TYPE DEVICE

EMPTY SPACE IN MEDIUM VOLTAGE, METAL CLAD SWITCHGEAR OR MCC

IRON CORE SHUNT REACTOR FOR REACTIVE COMPENSATION

400A
300A
SWITCH AND FUSE
400A = AMPERE SWITCH SIZE
300A = AMPERE FUSE SIZE

DISCONNECT SWITCH

SURGE ARRESTOR (SA)

SYSTEM OR EQUIPMENT GROUND

FUSE

MOTOR OPERATOR

METER
V = VOLT
A = AMPERE

KIRK KEY (FOR INTERLOCK)

CABLE TERMINATION

WIND GENERATOR
G1 = GENERATOR NUMBER 1

FUSED DISCONNECT

BLOCK ISLAND TRANSMISSION SYSTEM (BITS) NATIONAL GRID OWNED FACILITIES

BLOCK ISLAND WIND FARM (BIWF) OWNED FACILITIES

BLOCK ISLAND WIND FARM (BIWF)–DIRECT ASSIGNMENT FALICITIES

Reference Drawings

Rev	Date	Drawn	Description	Ch'k'd	App'd
F	10/30/2013	JM	REVISED PER COMMENTS	CD	
E	09/20/2013	JM	REVISED PER COMMENTS	CD	
D	09/16/2013	CD	REVISED PER COMMENTS	CD	
C	08/20/2013	CD	REVISED PER COMMENTS	CD	
B	08/13/2013	CD	REVISED REVENUE METER	CD	

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Client

DEEPWATERWIND

Title

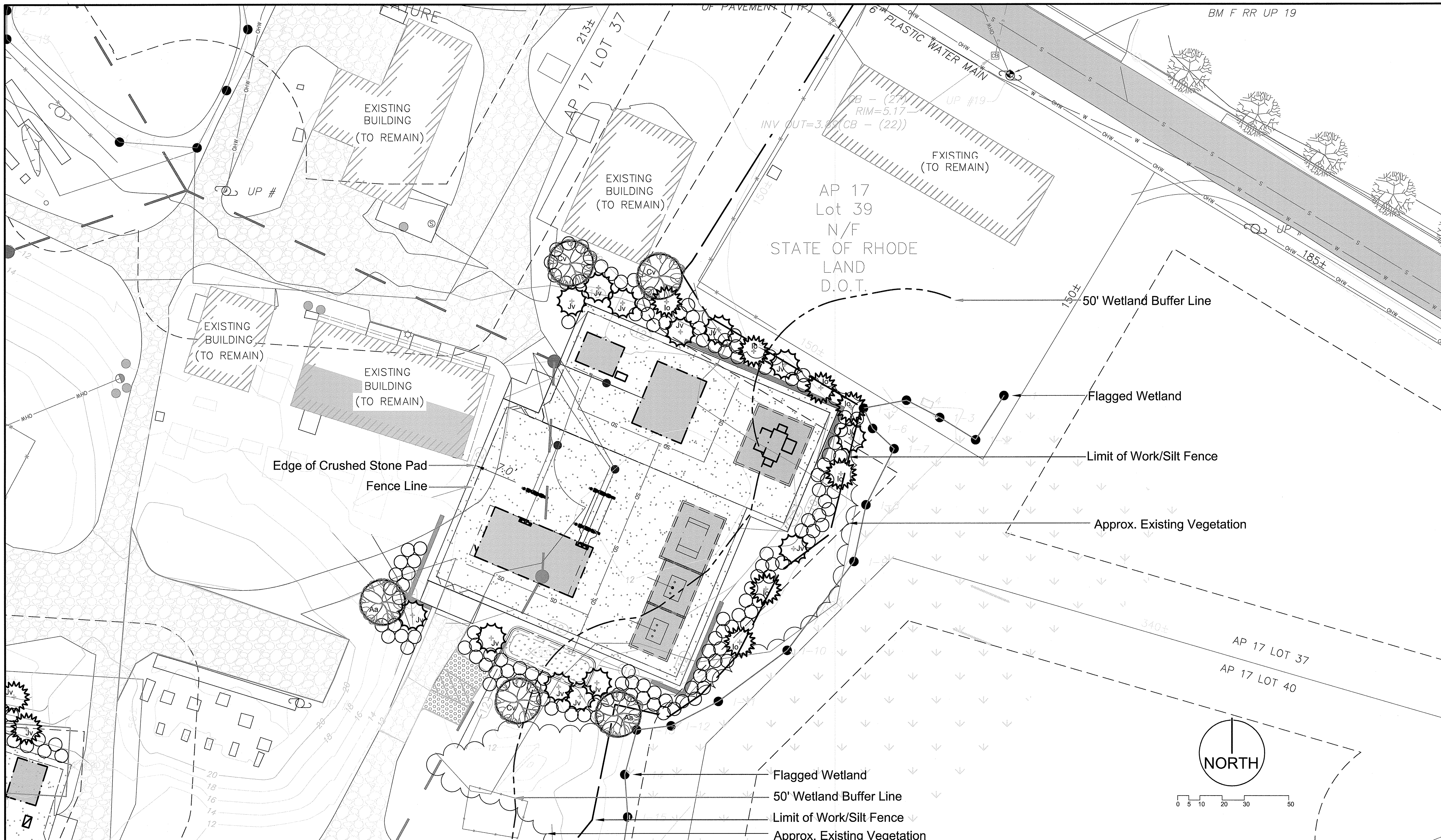
DEEPWATER BLOCK ISLAND
30MW RHODE ISLAND WIND FARM
34.5 kV BLOCK ISLAND
DILLON'S CORNER WAKEFIELD
INTERCONNECTION ONE LINE

PRELIMINARY
NOT FOR
CONSTRUCTION
REPLACE WITH ENGINEERS STAMP AT CONSTRUCTION AND/OR FABRICATION ISSUE IF REQUIRED BY PROJECT ADMINISTRATION MANUAL

Designed	CD	Eng check	CD
Drawn	CD	Approved	BK
Dwg check	BK	Project Mngr	CMD
Scale at ANSI E NTS		Date 08/7/2013	Rev F

Drawing Number
313194-E-101-SH2

APPENDIX A-2 TO LGIA: GENERAL ARRANGEMENT DIAGRAM



Plant Schedule: Screen Planting Alt. "A"			
Key	Botanical Name	Common Name	Quantity
	Evergreen Trees		
Io	Ilex opaca 'Jersey Girl'	Jersey Girl American Holly	7
Jv	Juniperus virginiana	Eastern Red Cedar	13
		Total:	20
	Deciduous Trees		
Aa	Amelanchier arborea	Downey Serviceberry	2
Cv	Crataegus viridis 'Winter King'	Winter King Hawthorn	3
		Total:	5
	Decidious Shrubs		
	Aronia melanocarpa	Black Chokeberry	30
	Ilex verticillata	Winterberry	25
	Morella (Myrica) pennsylvanica	Northern Bayberry	25
	Vaccinium corymbosum	High Bush Blueberry	25
	Viburnum dentatum	Arrowood Viburnum	30
		Total:	135

Key:

New Shrub

New Evergreen Tree

New Decidious Tree

Note: Plant material to be placed in the field by a V.L.A, LTD. representative.

Van Lent Associates
Landscape Architects and Planners

Van Lent Associates, Limited
P.O. Box 1208/ 292 Spring Street, Block Island, Rhode Island 02807
Tel. 401-466-2081 Fax.401-466-9984

Note: This regulatory submission shall not be used for construction purposes unless stamped "For Construction" and signed by a VLA representitive.

Revision	Date	Description
1	01.03.2012	Plant Material
2	01.09.2012	Plant Material
3	01.20.2012	Plant Material
4	02.27.2012	Format, Digitize and Revise Plants

Deepwater Wind
Block Island Power Substation
AP 17 Lots 35, 36, 37, 38 & 40
New Shoreham, Rhode Island
Screen Planting Plans *Alt. A*
Date: 11.21.2011 Scale: 1"= 20'-0"

Sheet 1 of 2

APPENDIX B TO LGIA

Milestones

1. **Selected Option Pursuant to Article 5.1:** Interconnection Customer selects the 5.1.1 Standard Option. Options described in Articles 5.1.2, 5.1.3 and 5.1.4 shall not apply to this LGIA.

2. **Milestones and Other Requirements for all Large Generating Facilities:** The description and entries listed in the following table establish the required Milestones in accordance with the provisions of the LGIP and this LGIA. The referenced section of the LGIP or article of the LGIA should be reviewed by each Party to understand the requirements of each milestone.

Item No.	Milestone Description	Responsible Party	Date	LGIP/LGIA Reference
1	Provide evidence of continued Site Control to System Operator, or $250,000 non-refundable deposit to Interconnecting Transmission Owner	Interconnection Customer	Completed	§ 11.3.1.1 of LGIP
2	Provide evidence of one or more milestones specified in § 11.3 of LGIP	Interconnection Customer	Complete, Purchase Power Agreement executed on June 30, 2010	§ 11.3.1.2 of LGIP
3	Commit to a schedule for payment of upgrades	Interconnection Customer	Completed upon execution of the LGIA. See Milestone 8.	§ 11.3.1.2 of LGIP
4	Provide either (1) evidence of Major Permits or (2) refundable deposit to	Interconnection Customer	Completed	§ 11.3.1.2 of LGIP

	Interconnecting Transmission Owner			
5	Provide certificate of insurance	Interconnection Customer and Interconnecting Transmission Owner	Within ten (10) days following execution of this LGIA	§ 18.3.9 of LGIA
6	Provide siting approval for Generating Facility and Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	By September 1, 2014	§ 7.5 of LGIP
7A	Receive Governmental Authority approval for any facilities requiring regulatory approval	Interconnection Customer	By September 1, 2014	§ 5.6.1 of LGIA
7B	Obtain necessary real property rights and rights-of-way for the construction of the Interconnecting Transmission Owner's Affiliate Interconnection Facilities	Interconnecting Transmission Owner	By September 1, 2014	§ 5.6.2 of LGIA
7C	Provide to Interconnecting Transmission Owner written authorization to proceed with:	Interconnection Customer		§ 5.5.2 and § 5.6.3 of LGIA

7C.1 7C.2 7C.3 7.C.4	pre-design design, equipment procurement and construction		Upon execution of this Agreement* By September 1, 2014*. By December 1, 2014*. By March 1, 2015*.	
7D	Provide quarterly written progress reports	Interconnection Customer and Interconnecting Transmission Owner	15 Calendar Days after the end of each quarter beginning the quarter that includes the date for Milestone 7C and ending upon completion of the Large Generating Facility and Interconnection Facilities	§ 5.7 of LGIA
8	Provision of Security to Interconnecting Transmission Owner pursuant to Section 11.5 of LGIA	Interconnection Customer	pre design pre-payment due by September 1, 2014. Remaining Pre-payments due with written authorizations from Milestone 7C	§§ 5.5.3 and 5.6.4 of LGIA
9	Provision of Security Associated with Tax Liability to Interconnecting	Interconnection Customer	Within 30 days after final invoice (Milestone 22)	§ 5.17.3 of LGIA

	Transmission Owner pursuant to Section 5.17.3 of LGIA			
10	Commit to the ordering of long lead time material for Interconnection Facilities	Interconnection Customer	N/A	§ 7.5 of LGIP
11A	Provide initial design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	By September 1, 2014	§ 5.10.1 of LGIA § 7.5 of LGIP
11B	Provide comments on initial design, engineering and specification for Interconnection Customer's Interconnection Facilities	Interconnecting Transmission Owner	Within 30 Calendar Days of receipt	§ 5.10.1 of LGIA § 7.5 of LGIP
12A	Provide final design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	By December 1, 2014	§ 5.10.1 of LGIA § 7.5 of LGIP
12B	Provide comments on final design, engineering	Interconnecting Transmission	Within 30 Calendar Days of receipt	§ 5.10.1 of LGIA

	and specification for Interconnection Customer’s Interconnection Facilities	Owner		§ 7.5 of LGIP
13	Deliver to Transmission Owner “as built” drawings, information and documents regarding Interconnection Customer’s Interconnection Facilities	Interconnection Customer	Within 120 Calendar Days of Commercial Operation date	§ 5.10.3 of LGIA
14	Provide protective relay settings to Interconnecting Transmission Owner for coordination and verification	Interconnection Customer	By March 1, 2015	§§ 5.10.1 of LGIA
15	Commencement of construction of Interconnection Facilities	Interconnecting Transmission Owner	30 days after receipt of written authorization to proceed by Interconnection Customer	§ 5.6 of LGIA
16	Submit updated data “as purchased”	Interconnection Customer	No later than 180 Calendar Days prior to Initial Synchronization Date	§ 24.3 of LGIA
17	In Service Date	Interconnection Customer	By June 1 , 2016	§ 3.3.1 and 4.4.5 of LGIP, § 5.1 of LGIA
18	Initial Synchronization Date	Interconnection Customer	By November 1, 2016	§ 3.3.1, 4.4.4, 4.4.5, and 7.5

				of LGIP
19	Submit supplemental and/or updated data – "as built/as-tested"	Interconnection Customer	Prior to Commercial Operation Date	§ 24.4 of LGIA
20	Commercial Operation Date	Interconnection Customer	By December 31, 2016	§ 3.3.1, 4.4.4, 4.4.5, and 7.5 of LGIP
21	Deliver to Interconnection Customer "as built" drawings, information and documents regarding Interconnecting Transmission Owner's Interconnection Facilities	Interconnecting Transmission Owner	Within 120 days of Commercial Operation Date	§ 5.11 of LGIA
22	Provide Interconnection Customer final cost invoices	Interconnecting Transmission Owner	Within 6 months of completion of construction of Interconnecting Transmission Owner Affiliate Interconnection Facilities	§ 12.2 of LGIA

* See Appendix C, Table 3 – Summary of Prepayments

3. **Milestones Applicable Solely for Long Lead Facility Treatment.** In addition to the Milestones above, the following Milestones apply to Interconnection Customers requesting Long Lead Facility Treatment: None.

APPENDIX C TO LGIA

Interconnection Details

1. Description of Interconnection:

Interconnection Customer shall install a 30 MW Large Generating Facility, rated at 30 MW gross and 29 MW net, with all studies performed at or below these outputs, and will be located in Block Island Sound, Rhode Island. The Generating Facility is comprised of five (5) fully-inverted wind turbine generators connected in series and rated at 6.0 MW each. The Parties agree that the inverter controls in each wind turbine generator shall satisfy the Generator Governor requirement set forth in Section 9.6.2.2 of this LGIA.

The Large Generating Facility shall receive:

> Interconnection Service at a level not to exceed 30 MW gross and 29 MW net for Summer and 30 MW gross and 29 MW net for Winter.

2. Detailed Description of Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	5
Manufacturer	Alstom or comparable
Model	SWT 6.0-154 or comparable
Designation of Generator(s)	Haliade -150
Excitation System Manufacturer	Alstom Inverter Technology
Excitation System Model	Alstom Inverter Technology
Voltage Regulator Manufacturer	Alstom Inverter Technology
Voltage Regulator Model	Alstom Inverter Technology

Generator Ratings	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 90 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 50 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 20 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above zero Degrees F	6.0/5.9
Station Service Load For Each Unit	__.1_ MW + j_.075__ MVAR
Overexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • PF = ±0.90 (at 34.5kV)
Underexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • • PF = ±0.90 (at 34.5kV)
Generator Short Circuit and Stability Data	
Generator MVA rating	6.5MVA– inverter technology
Generator AC Resistance	Inverter Technology 0.724 (0 …20ms) 99999 (LVRT ... ∞) *See Note Below
Subtransient Reactance (saturated)	Programmed – inverter technology
Subtransient Reactance (unsaturated)	Programmed – inverter technology
Transient Reactance (saturated)	Programmed – inverter technology
Negative sequence reactance	Programmed – inverter technology
Generator Step-up Transformer Data	
Number of units	5
Self Cooled Rating	6.5MVA
Maximum Rating	6.5MVA

Winding Connection (LV/HV)	0.9kV/34.5kV
Fixed Taps	±2 x 2.5%
Z1 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Positive Sequence X/R ratio primary to secondary Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Z0 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Project Grounding Transformer Data	
Number of units	1
Self Cooled Rating	n.a.
Maximum Rating	1.5 MVA @ 10 sec
Winding Connection (LV/LV/HV)	
Fixed Taps	none
Z1 primary to secondary at self cooled rating	Consistent with Section 3.E below
Positive Sequence X/R ratio primary to secondary	Consistent with Section 3.E below
Z0 primary to secondary at self cooled rating	Consistent with Section 3.E below

*Note: These are typical characteristic data for synchronous machines. Converter based wind turbines depend heavily in the converter control for the maximum currents and stability analysis.
An equivalence (to obtain the synchronous machine parameters) has been performed with the maximum short circuit currents from the converters in 100% voltage dip considering that the short circuit has 3 steps: a subtransient from the dip until 20ms, a transient between 20 ms until the LVRT (aprox. 150ms) and the steady-state value from the LVRT to the end of simulation.

3. Meteorological and Forced Outage Data Requirements for a Generating Facility that is an Intermittent Power Resource:

An Interconnection Customer whose Generating Facility is an Intermittent Power Resource having wind as the energy resource (referred to here in as “Wind Plant”) will be required to provide the following meteorological and forced outage data to the System Operator in the manner specified in the ISO New

England Operating Documents. Capitalized terms in this Appendix C.3 that are not defined in Section 1 of the Agreement shall have the meanings specified in the ISO New England Operating Documents.

A. Static Plant Data

Below are the static plant data requirements that describe the physical layout of the Wind Plant and any associated meteorological equipment as well as data relevant to the design and operation of the Wind Plant. The static plant data must be supplied to the System Operator in the manner specified in the ISO New England Operating Documents. The Interconnection Customer must keep the static plant data current and must inform the System Operator of any proposed datapoints changes.

1) Wind Plant:

a) Wind Turbine tower center coordinates (i.e., latitude and longitude in WGS84 DD-MM-SS.SS using GPS WAAS, or comparable, methodology) and ground elevation of turbines (in meters, to one decimal place).

b) Number of turbines.

c) Turbine model(s) including IEC wind class.

d) Density dependent turbine nominal power curves for each type of turbine in the plant for standard test conditions (e.g., air density equaling 1.225 kg/m^3) and for three additional values of density (for which the density values must be supplied): one power curve for normal operation at the long-term average density expected for the plant and one power curve each for normal operation at approximately 85% (+/-10%) and approximately 115% (+/-10%), respectively of the expected long-term average Wind Plant air density.

e) Hub height(s) (in meters to one decimal place).

f) Maximum plant nameplate capacity (in MW to two decimal places).

g) Cut-in wind speed(s) and time constants (if any, e.g., windspeed must be above 3.4 m/s for at least 5 minutes, etc.).

h) Cut-out wind speed(s) and time constants (if any).

i) Cut back in wind speed(s) and time constants (if any).

j) Cold temperature cutoff threshold(s) (in Degrees C to one decimal place).

k) High temperature cutoff threshold(s) (in Degrees C to one decimal place).

l) Any cold weather operation packages and their effects on wind turbine operational envelope (e.g. blade and/or gearbox heaters, etc. that extends cold temperature cut-out to below xx degrees, etc.).

m) Wind turbine icing behavior:

i. Triggers for icing related shutdowns (e.g., temperatures, relative humidities, out-of-balance conditions, etc.).

ii. Triggers for release from icing related shutdowns (e.g., manual reset, temperatures, hysteresis, etc.).

n) For all plant wind speed and direction measuring devices (i.e., nacelle-level wind measuring devices):

i. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights) and calibration curves and/or reports.

ii. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data and the mitigation measures employed (e.g., diagram of location with respect to the nacelle and rotor).

o) Descriptions of any permitting or administrative restrictions such as requirements to reduce or to cease power production during certain hours or during certain events or wind conditions.

p) For model training purposes, any available historical information required by the wind power forecaster regarding plant power output, plant meteorological conditions, and conditions that may have caused power output to be below theoretical maximum power output given the experienced wind speeds may also be required to be provided.

2) Met gathering station(s):

a. Center of structure(s) coordinates (using the same method listed above for turbine in the Wind Plant) and ground elevation of met station(s).

b. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights).

c. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data (e.g., met-tower dimensions and profile) and the mitigation measures employed (e.g. mounting arm dimensions and orientations).

B. Real-Time Data

Below is the real-time operational and meteorological data requirements for Wind Plant operators that must be provided to the System Operator. The real-time operational and meteorological data must be electronically and automatically transmitted to the System Operator over a secure network using the protocol specified in the ISO New England Operating Documents. This information is required with a high degree of accuracy and reliability.

1) Availability:

The Wind Plant operator's real-time data transfer process and data gathering equipment shall be designated to operate at all times.

2) Required Data:

a) At a minimum, nacelle-level wind speed and wind direction measurements must be provided from the highest wind turbine (i.e., wind turbine hub elevation in terms of elevation above mean sea level) and a minimum of one wind turbine at the maximal value of each of the four true cardinal directions (i.e., the farthest true North, South, East, and West) in each Wind Turbine Group within the plant. Additionally, the wind turbine nearest the capacity-weighted centroid of the Wind Plant must also report wind speeds and directions. If any wind turbine within a Wind Turbine Group satisfies more than one of these conditions then it may be used to fulfill all conditions that it satisfies (e.g., if the highest wind turbine in a Wind Turbine Group is also the farthest North and the farthest East, it may be used to supply data for all three of these categories). Where more than one turbine satisfies these conditions, preference should be given to those turbines that will be least affected by Wind Plant wake effect from the prevailing wind direction(s). Finally, where a Wind Turbine Group contains 10 or less wind turbines only the nacelle-level data from the highest wind turbine nacelle is required. The locations of wind turbines with nacelle-level equipment providing data must be referenced to the Static Plant Data supplied locations.

b) Ambient temperature, air pressure and relative humidity must be measured, at a minimum, at one location within the plant (preferably as near to the capacity-weighted centroid of the Wind Plant as possible) whose height above ground may be in the range of 2 m to 10 m (or up to 30 m above mean sea level for offshore Wind Plants) and the measurement height above ground (or mean sea level for offshore Wind Plants) must be stated to within 10 cm.

3) Frequency

Minimum frequencies of the real-time data Wind Plant operators must provide are specified in the ISO New England Operating Documents.

C. Outage Coordination

Wind Plants shall submit daily outages in advance to perform routine maintenance work, which in many cases may have no effect on their overall MW capability. Therefore:

1) All Wind Plants must submit Wind Plant Future Availability to the System Operator.

2) If the Wind Plant does not have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, and is not a Qualified Generator Reactive Resource, only Wind Plant Future Availability must be reported to the System Operator.
3) Any Wind Plant that does have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, or that is a Qualified Generator Reactive Resource, must report Wind Plant Future Availability, and also submit an outage request to the System Operator only when the outage will derate the plant to the point that the available nameplate is less than its Capacity Supply Obligation and/or Qualfied VARs.

4. Other Description of Interconnection Plan and Facilities:

A. Studies

1. Interconnection Feasibility Study: N/A.
2. Interconnection System Impact Study: Completed: Q405 System Impact Study – March 2014;; On April 16, 2014, the Proposed Plan Application received Reliability Committee recommendation for approval by the System Operator.
3. Interconnection Facilities Study: Waived
4. Optional Interconnection Study: None
5. Supplemental System Impact Study: None

B. Interconnection Customer's Interconnection Facilities.

The Interconnection Customer will own the Interconnection Customer's Interconnection Facilities described in Appendix A.1.b to this Agreement.

The Interconnection Customer will engineer, procure, install, own and maintain the telemetering (RTU) equipment and the telecommunication circuits that are installed at the Block Island Substation and which are necessary to interface and communicate with the System Operator Communications Front End (CFE) network and the Interconnecting Transmission Owner's Local Control Center. Once the RTU has been configured by the Interconnection Customer, the Interconnecting Transmission Owner will check the reporting of the Interconnection Customer RTU to ensure that it is sending the appropriate signals to the Local Control Center. ISO-NE will check the RTU telemetry and control signals as required according to the ISO-NE CFE Interface specifications.

Interconnecting Transmission Owner and Interconnecting Transmission Owner's Affiliate agree to work with the Interconnection Customer and landowner to obtain adequate physical space and the necessary rights of use, rights of way and easements within the Block Island Substation for Interconnection Customer to safely and conveniently install, operate and maintain such data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment as are agreed by the Interconnection Customer and Interconnecting Transmission Owner for the safe and reliable operations of the Generating Facility, which equipment shall be located within the Interconnection Customer's Control Building, as identified in Appendix A-2. Interconnecting Transmission Owner's Affiliate shall be responsible for all site preparation and civil works for such space as part of the Direct Assignment Facilities, but shall have no responsibility for the construction of Interconnection Customer's Control Building or the equipment therein.

Properly accredited representatives of the Interconnecting Transmission Owner shall at all reasonable times have access to the Interconnection Customer's Interconnection Facilities at the transition structure to make reasonable inspections and obtain information required in connection with this Agreement.

Upon notice to the Interconnection Transmission Owner Affiliate's control room, properly accredited representatives of the Interconnection Customer shall at all reasonable times have access to the Interconnection Facilities to make reasonable inspections and obtain information required in connection with this Agreement.

C. Interconnecting Transmission Owner's Interconnection Facilities

The Interconnecting Transmission Owner will own, operate and maintain the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A.1.c to this Agreement at the Interconnection Customer's expense.

Interconnecting Transmission Owner's Affiliate will own, operate and maintain the Interconnecting Transmission Owner's Affiliate's Interconnection Facilities described in Appendix A.1.c to this Agreement, at the Interconnection Customer's expense.

D. Testing

Testing of the Interconnection Facilities shall be performed by Interconnection Customer. Prior to conducting the tests, Interconnection Customer shall submit the proposed testing protocols to the Interconnecting Transmission Owner's Affiliate. The Interconnecting Transmission Owner's Affiliate shall have the right to review and comment on such proposed testing protocols (the "Test Protocols"). Within ten (10) days after receipt of the Test Protocols from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Protocols or (B) reject the Test Protocols by providing written notice stating the reasons for the rejection and specifying the changes necessary to make the Test Protocols acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Protocols within ten (10) days, then Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Protocols as originally submitted by Interconnection Customer.

At least five (5) days prior to conducting the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate, and Interconnecting Transmission Owner's Affiliate prior to shall have the right to witness the tests.

Following the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate of the results of the tests (the "Test Results"). Within ten (10) days after receipt of the Test Results from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Results or (B) object to the Test Results by providing written notice stating the reasons for the rejection and specifying its objections and the changes necessary to make the Test Results acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Results within ten (10) days, then

Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Results.

E. Protection Philosophy

Interconnection Transmission Owner and Interconnection Customer shall jointly establish a Protection Philosophy in compliance with Sections 9.6.2.3, 9.7.3, 9.7.4.1, 9.7.4.5 and 9.7.5 of this LGIA which shall be the design basis for the final engineering of the Interconnection Facilities. National Grid Connection Specifications ESB-756 shall be the prevailing guideline for interconnection and protection design development.

4. Special Conditions

A. Cost Responsibility

1. General

Pursuant to the terms of the Agreement, the Interconnection Customer shall be solely responsible for all reasonable costs incurred by the Interconnecting Transmission Owner and its Affiliate as a result of the Direct Assignment Facilities and/or services provided under this Agreement in excess of the estimated costs and charges provided in this Appendix C to this Agreement that are not otherwise recovered under the Tariff.

Such costs are intended to be recovered by, but would not be limited to, the charges specified below.

<u>Interconnection Facilities</u>

The Interconnection Customer shall be responsible for direct assignment facilities charges calculated in accordance with the formulae set forth in Schedule 21 – NEP, Attachment DAF of the OATT as may be in effect from time to time ("DAF Charge"). A copy of the presently effective transmission DAF Charge is provided in

Appendix C, Exhibit 1 for illustrative purposes. Estimated Annual DAF Charges are provided in Appendix C, Table 1.

Metering and Related Equipment

The Interconnection Customer will own the revenue meter. The Interconnecting Transmission Owner's Affiliate will own and maintain the appropriate metering transformers, associated test switches, and a remote terminal unit ("RTU") and related equipment. Metering equipment must conform to Tariff and Operating Procedures in effect and amended from time to time, and will be subject to the requirements of the Interconnecting Transmission Owner. The Interconnecting Transmission Owner shall be present during commissioning of the revenue meter and shall have the right to witness any testing of said meter. The Interconnection Customer grants permission to Interconnecting Transmission Owner's personnel from various departments including engineering, distribution planning, transmission planning and T&D, to access any and all Interconnection Customer RTU data which is telemetered to Interconnecting Transmission Owner's control room. Interconnecting Transmission Owner agrees not to share this data with its sales and marketing personnel pursuant to applicable FERC rules and regulations. Additionally, the Interconnecting Transmission Owner agrees not to share this data with anyone other than those listed above without the prior written consent of an officer of the Interconnection Customer.

If, at any time, any metering equipment is found to be inaccurate by the requirements set forth in ISO New England Operating Procedure No. 18 - Metering and Telemetering Criteria, Interconnecting Transmission Owner shall cause such metering equipment to be made accurate or replaced, and meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the preceding month shall be made except by agreement of the Interconnection Customer and Interconnecting Transmission Owner.

The Interconnecting Transmission Owner and Interconnection Customer shall comply with any reasonable request of the other concerning the sealing of the meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Generating Facility. If either Interconnecting Transmission Owner or Interconnection Customer believes that there has been a meter failure or stoppage, it shall immediately notify the other.

B. Termination Charge

In addition to the payment obligations specified in Article 2 of this Agreement for termination by the Interconnection Customer prior to the expiration of the term of this Agreement, the Interconnection Customer agrees that it will be responsible for the DAF Charges for the original term of this Agreement as determined in accordance with the formula set forth in Schedule 21 – NEP, Attachment DAF of the OATT or as contained in an alternative cost recovery mechanism that the FERC may have approved at the time of the termination.

The Interconnection Customer reserves its right to initiate or participate in a proceeding before the FERC to contest the reasonableness of the above charges.

C. Station Service

Interconnection Customer shall be responsible for properly arranging its Station Service electric requirements, including, auxiliary service or backup service.

D. Regulatory Compliance

The Parties agrees to provide each other with notices and copies of all filings, including any applicable FERC filings pertaining to the Interconnection Facilities and/or this Agreement.

E. Radial Service

Interconnection Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Interconnecting Transmission Owner's Affiliate Wakefield Substation and that there will be an interruption to interconnection service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable. Interconnecting Transmission Owner or its Affiliate will notify Interconnection Customer of any planned interruption in service prior to such interruption and of any unplanned interruption as soon as reasonably practicable.

F. Losses

The metering equipment shall be compensated internally in order to record the delivery of electricity in a manner that accounts for any energy losses occurring between the Metering Point and the Point of Interconnection both when the Large Generating Facility is delivering energy to the Point of Interconnection and when Station Service power is delivered to the Point of Interconnection for the benefit of the Interconnection Customer, consistent with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents or procedures.

G. Payment Schedule and Financial Security Requirements

Interconnection Customer shall make prepayments to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner’s Interconnection Facilities and the Interconnecting Transmission Owner’s Affiliate Interconnection Facilities by wire transfer in immediately available funds in accordance with the payment schedule in Appendix C, Table 3 of this Agreement**.**

1. The Summary Table of Prepayments as shown in Appendix C, Table 3 sets forth four (4) prepayments (“Prepayments”).

2. The sum of the four prepayments made by Interconnection Customer shall be referred to as the "Total Estimated Cost". Within six (6) months following the In-Service Date, Interconnecting Transmission Owner shall inform Interconnection Customer of the final actual costs to design and install the Interconnecting Transmission Owner's Interconnection Facilities and Interconnecting Transmission Owner’s Affiliate Interconnection Facilities ("Final Actual Installed Cost"), plus the actual tax gross up amount, as calculated by the Interconnecting Transmission Owner in accordance with the formula described in Article 5.17.4 of this Agreement ("Actual Tax Gross Up Amount") and shall provide Interconnection Customer with a final written invoice ("Final Invoice")

for the difference between the Final Actual Installed Cost and the Total Estimated Cost ("Final Balance").

On or before thirty (30) days following the date of the Interconnecting Transmission Owner's Final Invoice, the Interconnection Customer shall pay the Final Balance to Interconnecting Transmission Owner by wire transfer in immediately available funds; provided that, subject to compliance with Article 12.2 of this Agreement, in the event that the Total Estimated Cost exceeds the Final Actual Installed Cost, any such excess amount shall be refunded to Interconnection Customer as an overpayment.

3. The Interconnecting Transmission Owner shall not be obligated to commence and may not commence any of the tasks listed in Appendix B of this Agreement until (i) the Interconnecting Transmission Owner has received written notice from Interconnection Customer to proceed with such tasks, and (ii) the Interconnecting Transmission Owner has received the Prepayment required under this Section G corresponding to such task listed in Appendix B.

4. The Interconnection Customer and Interconnecting Transmission Owner agree that the Final Actual Installed Cost shall be considered a construction advance for tax purposes except as otherwise provided in Article 5.17.5 of this Agreement. On or before the date that Interconnection Customer pays the Interconnecting Transmission Owner's Final Invoice, Interconnection Customer shall present to the Interconnecting Transmission Owner a Letter of Credit ("LOC"), in form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed, in a face amount representing the estimated tax gross up amount on the Final Actual Installed Cost. For purposes of this Agreement, the Actual Tax Gross Up Amount shall be the product of (i) the Final Actual Installed Cost and (ii) the Interconnecting Transmission Owner’s or its Affiliate’s tax gross up rate in existence at the In-Service Date as shown in Appendix C, Table 1 of this Agreement.

5. The Interconnection Customer shall be responsible for all costs associated with the LOC, including, without limitation, the costs of obtaining, maintaining and replacing such LOC and reimbursement of the LOC Bank (as such term is defined below). Each

LOC shall be in a form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed. Each LOC shall be an irrevocable, unconditional, and transferable standby letter of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (the "LOC Bank") provided that the Interconnection Customer is not an affiliate of the LOC Bank, the LOC Bank has at least ten billion dollars ($10,000,000,000) in assets and the LOC Bank's lowest credit rating is at least A2 from Moody's Investors Service or A from Standard and Poor's Ratings Services or Fitch, Inc. ("LOC Bank Requirement(s)"). If at any time (i) the LOC Bank fails to satisfy any LOC Bank Requirement, or (ii) the LOC Bank advises that it will not renew the LOC beyond its current expiration date ("Notice of Cancellation"), then, the Interconnection Customer shall deliver a replacement letter of credit from a bank meeting the LOC Bank Requirements and the other requirements of this Paragraph and this Agreement. Such replacement letter of credit shall be delivered to Interconnecting Transmission Owner promptly but in no event later than ten (10) Calendar Days following the date on which the LOC Bank's first fails to satisfy an LOC Bank Requirement or, in the case of a Notice of Cancellation, thirty (30) Calendar Days prior to the current expiration date of the applicable LOC. If Interconnection Customer fails to provide such replacement LOC by the applicable date contemplated by this paragraph (and in compliance with the other requirements hereof), Interconnecting Transmission Owner shall have the immediate right to draw the full amount remaining under the applicable existing LOC.

6. Any LOC delivered pursuant to this Section G, as such LOC may be replaced, modified, or amended, from time to time, as contemplated above, shall serve as security for Interconnection Customer's obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under or in connection with this Agreement for the tax gross up on the cost of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, and Interconnecting Transmission Owner's Affiliate Interconnection Facilities and shall not be used for any other purpose.

7. Interconnection Customer shall maintain the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in full force and effect at all times; provided, however, that Interconnection Customer may terminate such LOC, any modification or amendment thereof, and any replacement for such LOC, only upon termination of Interconnection Customer's indemnification obligation in accordance with Article 5.17.3 of this Agreement. The Interconnecting Transmission Owner shall have the right to draw upon the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in the event the Interconnection Customer fails to timely meet any of its obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner or its Affiliate from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner or its Affiliate under or in connection with this Agreement, as well as any interest and penalties.

8. If Interconnection Customer fails to make any payments required under this Appendix C or the Agreement, or fails to provide and maintain the security contemplated above, each in the form, amounts, and at the times, required, Interconnecting Transmission Owner or its Affiliate may exercise any rights, and pursue any remedies, available to it under this Agreement, including, without limitation, Article 12. If any payment date or other due date specified in this Section G falls on a weekend or a federal bank holiday, then such payment or due date shall be deemed to be the next business day.

APPENDIX C

EXHIBIT 1
Transmission DAF Charge
Monthly Rate Formula

The Monthly Rate shall equal the Annual Facilities Charge divided by 12.

The Annual Facilities Charge shall be calculated in a manner consistent with Schedule 21 - NEP, Attachment DAF of the OATT, determination of the Annual Facilities Charge for transmission facilities, which section of Schedule 21 currently provides as follows:

"The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility."

"The Gross Plant Investment shall be the investment from the plant accounting records associated with the facility."

"The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a)."

"To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I (B), and I. (C) of Attachment RR, Exhibit 1 of Schedule 21 - NEP."

"If the Interconnection Customer permanently terminates service in advance of the term of its Agreement, the Interconnection Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to Schedule 21 - NEP, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination."

"Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records."

APPENDIX C

Table 1 – Estimated Annual DAF Charges

The costs listed in this Appendix C, Table 1 are the estimates provided in Table 2 and are provided for illustrative purposes only. The DAF Charge will be adjusted to reflect the Final Actual Installed Cost and the Actual Annual Transmission Carrying Charges as determined from year to year. In the event that the Project is terminated, Interconnecting Transmission Owner shall refund to Interconnection Customer all Prepayments received in excess of Interconnecting Transmission Owner's expenses and payment obligations incurred in fulfillment of this Agreement.

Components	Estimated Cost
Pre-design*	$50,000
Design ITO Affiliate's Interconnection Facilities	$347,500
Procure ITO Affiliate's Interconnection Facilities	$662,500
Construct ITO Affiliate's Interconnection Facilities	$1,590,000
Estimated Total Customer Payments (see Tables 2 & 3)	$2,650,000
Tax Gross Up (0.3554[1] x Total Customer Payments)	$941,810

*A limited notice to proceed to be issued upon execution of this agreement will authorize initial expenditures not to exceed $50,000 and to be reimbursed no later than September 1, 2014.

Estimated Annual DAF Charge[2]	
Gross Plant Investment (w/out tax gross up)	$2, 650,000
Times	
Annual Carrying Charge Rate	7.48%
Equals	
Annual DAF Charge	$198,220

[1] The tax gross up rate shown in this Appendix C, Table 1 is the Interconnection Transmission Owner's 2009 tax gross up rate, which is subject to change. The Actual tax gross up rate will be the rate that is in existence at the In-Service Date.

[2] Annual DAF Charges are calculated by multiplying Year-end Gross Plant Investment (GPI) by the Annual Carrying Charge rate that is in effect at the time. The Annual Carrying Charge rate shown in this Appendix C, Table 1 is the 2011 rate and is provided for illustrative purposes only. The Interconnection Customer will pay the Annual DAF Charge on a monthly basis, which will be estimated as the Annual DAF Charges divided by 12. In no event shall the NEP DAF Charge be calculated on any basis different from the formula set forth in Schedule 21 – NEP, Attachment DAF of the OATT as may be in effect from time to time.

APPENDIX C

Table 2 – Estimated Cost of Interconnection Facilities for DAF Charges

Interconnection Facility	Total Estimated Cost	% of Total	Interconnection Customer Cost
34.5kV breaker at POI	$2,500,000*	20%	$500,000
Grounding transformer	$500,000	100%	$500,000
34.5kV overhead circuit	$300,000**	50%	$150,000
34.5kV underground circuit	$3, 000,000**	50%	$1,500,000
Total	$5,800,000		$2, 650,000

* Estimated cost of five breaker switchgear arrangement at Block Island Substation

** The Interconnection Customer is only responsible for the cost of the generator lead between the Point of Change of Ownership and the Point of Interconnection. A second 34.5kV line is for the tie of the Block Island Substation to the mainland, which is being funded outside of this Agreement. The two lines are running in parallel ductbanks from the shore and on common poles on the Block Island property. They were estimated together and a cost of one-half the total is used as a proxy cost for either line.

Table 3 – Summary Table of Prepayments

Date	% of Total	Amount
Milestones 8and7C2	**15%**	**$397,500**
Milestone 7C3	**25%**	**$662,500**
Milestone 7C4	**60%**	**$1,590,000**
Total		**$2,650,000**

APPENDIX D TO LGIA

Security Arrangements Details

Infrastructure security of the New England Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day New England Transmission System reliability and operational security. The Commission will expect System Operator, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected to the New England Transmission System to comply with the recommendations offered by the Critical Infrastructure Protection Committee and, eventually, best practice recommendations from NERC. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

APPENDIX E TO LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between System Operator, Interconnecting Transmission Owner and Interconnection Customer.

[*Date*]
New England Power Company
Attn: Director, Transmission Commercial
East Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: Block Island Wind Farm Large Generating Facility

Dear ________________:

On [Date] Deepwater Block Island Wind, LLC has completed Trial Operation of Unit No. ___. This letter confirms that Deepwater Block Island Wind, LLC commenced commercial operation of Unit No. ___ at the Large Generating Facility, effective as of [Date plus one day].

Thank you.

[*Signature*]

[*Interconnection Customer Representative*]

APPENDIX F TO LGIA

Addresses for Delivery of Notices and Billings Notices:

System Operator: N/A

Interconnecting Transmission Owner:

New England Power Company
Attn: Director, Transmission Commercial
West Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

With copy to:
New England Power Company
Attn: Lead Account Manager
West Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

Interconnection Customer:

Deepwater Block Island Wind, LLC
C/O Deepwater Wind, LLC
Attn: Chris van Beek, President
56 Exchange Terrace, Suite 101
Providence, RI 02903

Billings and Payments:

System Operator: N/A

Interconnecting Transmission Owner:

New England Power Company
Attn: Transmission Billing
West Wing, Floor 2
40 Sylvan Road
Waltham, MA 02451

Interconnection Customer:

Deepwater Block Island Wind, LLC
C/O Deepwater Wind, LLC
Attn: Contract Admin
56 Exchange Terrace, Suite 101
Providence, RI 02903

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

System Operator: N/A

Interconnecting Transmission Owner:

Telephone: (781) 907-2409
Fax: (781) 296-8088
Email: edward.m.kremzier@nationalgrid.com

Interconnection Customer:

Telephone: (401)-648-0606
Fax: (401)-228-8004
Email: kadmin@dwwind.com

DUNS Numbers:

Interconnection Customer: 831810895
Interconnecting Transmission Owner: 006952881

APPENDIX G TO LGIA

Interconnection Requirements For A Wind Generating Plant

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains

following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT. Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9

cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the System Operator and Interconnecting Transmission Owner, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind generating plant is in operation. Wind generating plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind generating plant shall provide SCADA capability to transmit data and receive instructions from the System Operator and Local Control Center to protect system reliability. The System Operator, Interconnecting Transmission Owner and the wind generating plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind generating plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Attachment B

MARKED Version of
Original Service Agreement No. IA-NEP-26
New England Power Company
Large Generator Interconnection Agreement
With Deepwater Block Island Wind, LLC

~~**APPENDIX 6**~~

LARGE GENERATOR INTERCONNECTION AGREEMENT

BY AND BETWEEN

DEEPWATER BLOCK ISLAND WIND, LLC

AND

NEW ENGLAND POWER COMPANY d/b/a NATIONAL GRID

LARGE GENERATOR INTERCONNECTION AGREEMENT

TABLE OF CONTENTS

THIS ~~STANDARD~~ LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ~~____~~30th day of ~~________ 20__~~June 2014, by and between ~~________________, a ________________~~Deepwater Block Island Wind, LLC, a company organized and existing under the laws of the State~~/Commonwealth~~ of ~~________________~~Delaware ("Interconnection Customer" with a Large Generating Facility), ~~ISO~~and New England ~~Inc., a non-stock corporation~~Power Company d/b/a National Grid, a company organized and existing under the laws of the ~~State of Delaware ("System Operator"), and ________________, a ________________ organized and existing under the laws of the State/~~Commonwealth of ~~________________~~Massachusetts ("Interconnecting Transmission Owner"). Under this Agreement the Interconnection Customer~~, System Operator,~~ and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator") is the central dispatching agency provided for under the Transmission Operating Agreement ("TOA") which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the ISO New England Inc. Transmission, Markets and Services Tariff (Tariff); and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and

WHEREAS~~, System Operator~~**,** Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the generator interconnection process provided for in Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under Schedule 22. Capitalized terms in this Agreement or Schedule 22 that are not defined in this ~~Article 1~~Agreement shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Transmission System.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Parties.

At-Risk Expenditure shall mean money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case shall have the meaning specified in Section 2.3 of the Large Generator Interconnection Procedures ("LGIP").

Base Case Data shall mean the Base Case power flow, short circuit, and stability data bases used for the Interconnection Studies by ~~the System Operator,~~ Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

~~**Capacity Capability Interconnection Standard ("CC Interconnection Standard")** shall mean the criteria required to permit the Interconnection Customer to interconnect in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility, and in a manner that ensures intra-zonal deliverability by avoidance of the redispatch of other Capacity Network Resources, as detailed in the ISO New England Planning Procedures.~~

~~**Capacity Network Resource ("CNR")** shall mean that portion of a Generating Facility that is interconnected to the Administered Transmission System under the Capacity Capability Interconnection Standard.~~

~~**Capacity Network Resource Capability ("CNR Capability")** shall mean: (i) in the case of a Generating Facility that is a New Generating Capacity Resource pursuant to Section III.13.1 of the Tariff or an Existing Generating Capacity Resource that is increasing its capability pursuant to Section III.13.1.2.2.5 of the Tariff, the highest megawatt amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff, and, if applicable, as specified in a filing by the System Operator with the Commission in accordance with Section III.13.8.2 of the Tariff, or (ii) in the case of a Generating Facility that meets the criteria under Section 5.2.3 of this LGIP, the total megawatt amount determined pursuant to the hierarchy established in Section 5.2.3. CNR Capability shall not exceed the maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter. Where the Generating Facility includes multiple production devices, the CNR Capability shall not exceed the aggregate maximum net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 90 degrees F for Summer and at or above 20 degrees F for Winter.~~

~~**Capacity Network Resource Group Study ("CNR Group Study")** shall mean the study performed by the System Operator under Section III.13.1.1.2.3 of the Tariff to determine which resources qualify to participate in a Forward Capacity Auction.~~

~~**Capacity Network Resource Interconnection Service ("CNR Interconnection Service")** shall mean the Interconnection Service selected by the Interconnection Customer to interconnect its Large Generating Facility with the Administered Transmission System in accordance with the Capacity Capability Interconnection Standard. An Interconnection Customer's CNR Interconnection Service shall be for the megawatt amount of CNR Capability. CNR Interconnection Service does not in and of itself convey transmission service.~~

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, but not be limited to, information that is confidential pursuant to the ISO New England Information Policy.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by the Commission or if filed unexecuted, upon the date specified by the Commission.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission Owner, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or any Affected System to which the New England Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Engineering & Procurement ("E&P") Agreement shall mean an agreement that authorizes the Interconnection Customer, Interconnecting Transmission Owner and any other Affected Party to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner's Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner shall mean a Transmission Owner that owns, leases or otherwise possesses an interest in the portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Large Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer shall mean any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Generating Facility with the Administered Transmission System under the Standard Large Generator Interconnection Procedures.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the ~~System Operator,~~ Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Feasibility Study.

Interconnection Request (a) shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System ~~as either a CNR or a NR~~; (ii) increase the energy capability or capacity capability of an existing Generating Facility; (iii) make a Material Modification to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System; or (iv) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System~~; or (v) change from NR Interconnection Service to CNR Interconnection Service~~. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service shall mean the service provided by ~~System Operator and~~ the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, the Interconnection Facilities Study and the Optional Interconnection Study described in the Standard Large Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement shall mean any of the following agreements: the Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, the Interconnection Facilities Study Agreement, and the Optional Interconnection Study Agreement attached to the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Large Generating Facility shall mean a Generating Facility having a maximum gross capability at or above zero degrees F of more than 20 MW.

Long Lead Time Generating Facility ("Long Lead Facility") shall mean a Generating Facility with an Interconnection Request for CNR Interconnection Service that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Section 3.2.3 of the LGIP.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Initial Synchronization Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; or (iv) except as provided in Section 3.2.3.4 of the LGIP, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6 of the LGIP, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

~~**Network Capability Interconnection Standard ("NC Interconnection Standard")** shall mean the criteria required to permit the Interconnection Customer to interconnect in a manner that avoids any significant adverse effect on the reliability, stability, and operability of the New England Transmission System, including protecting against the degradation of transfer capability for interfaces affected by the Generating Facility, as detailed in the ISO New England Planning Procedures.~~

~~**Network Resource ("NR")** shall mean the portion of a Generating Facility that is interconnected to the Administered Transmission System under the Network Capability Interconnection Standard.~~

~~**Network Resource Capability ("NR Capability")** shall mean the maximum gross and net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient~~

~~temperature at or above 50 degrees F for Summer and at or above 0 degrees F for Winter. Where the Generating Facility includes multiple energy production devices, the NR Capability shall be the aggregate maximum gross and net megawatt electrical output of the Generating Facility at the Point of Interconnection at an ambient temperature at or above 50 degrees F for Summer and at or above 0 degrees F for Winter. NR Capability shall be equal to or greater than the CNR Capability. In the case of a Generating Facility that meets the criteria under Section 5.2.4 of this LGIP, the NR Capability shall equal the total megawatt amount determined pursuant to Section 5.2.4.~~

~~**Network Resource Interconnection Service ("NR Interconnection Service")** shall mean the Interconnection Service selected by the Interconnection Customer to interconnect its Generating Facility to the Administered Transmission System in accordance with the Network Capability Interconnection Standard. An Interconnection Customer's NR Interconnection Service shall be solely for the megawatt amount of the NR Capability. NR Interconnection Service in and of itself does not convey transmission service.~~

Network Upgrades shall mean the additions, modifications, and upgrades to the New England Transmission System required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the Administered Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party shall mean the ~~System Operator,~~ Interconnection Customer and Interconnecting Transmission Owner or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to Interconnecting Transmission Owner's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Administered Transmission System.

Queue Position shall mean the order of a valid request in the New England Control Area, relative to all other pending requests in the New England Control Area, that is established based upon the date and time of receipt of such request by the System Operator. Requests are comprised of Interconnection Requests, requests for Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. For purposes of this LGIA, references to a "higher-queued" Interconnection Request shall mean one that has been received by the System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as "lower-queued."

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property for which new interconnection is sought; (b) that the Interconnection Customer holds a valid written leasehold interest in the real property for which new interconnection is sought; (c) that the Interconnection Customer holds a valid written option to purchase or leasehold property for which new interconnection is sought; (d) that the Interconnection Customer holds a duly executed written contract to purchase or leasehold the real property for which new interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the New England Transmission System during their construction. The ~~System Operator,~~ Interconnection Customer~~,~~ and Interconnecting Transmission Owner, ~~and any Affected Party as deemed appropriate by System Operator~~ in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. ~~System Operator and~~ Interconnecting Transmission Owner, shall promptly and jointly file this LGIA with the Commission upon execution in accordance with Section 11.3 of the LGIP and Article 3.1, if required.

2.2 Term of Agreement. This LGIA, subject to the provisions of Article 2.3, and by mutual agreement of the Parties, shall remain in effect for a period of ~~________ years from the Effective Date (*term to be specified in individual Agreement, but in no case should the term be less than ten* (*10*~~twenty (20) years from the ~~*Effective Date or such other longer period as the Interconnection Customer may request)*~~Commercial Operations Date and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by the Interconnection Customer, subject to continuing obligations of this LGIA and the Tariff, after giving the ~~System Operator and~~ Interconnecting Transmission Owner ninety (90) Calendar Days advance written notice, or by ~~System Operator or~~ Interconnecting Transmission Owner notifying the Commission after a Generating Facility retires pursuant to the Tariff, provided that if an Interconnection Customer exercises its right to terminate on ninety (90) Calendar Days, any reconnection would be treated as a new interconnection request; or this LGIA may be terminated by Interconnecting Transmission Owner ~~or System Operator~~ by notifying the Commission after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Each Party may terminate this LGIA in accordance with Article 17.

Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing, if applicable, with the Commission of a notice of termination of this LGIA, which notice has been accepted for filing by the Commission. Termination of the LGIA shall not supersede or alter any requirements for deactivation or retirement of a generating unit under ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

2.4 Termination Costs. If a Party elects to terminate this LGIA pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party(ies), as of the date of such Party's(ies') receipt of such notice of termination, that are the responsibility of such Party(ies) under this LGIA. In the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by the Commission:

2.4.1 With respect to any portion of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades to the extent covered by this LGIA, that have not yet been constructed or installed, the Interconnecting Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Interconnecting Transmission Owner shall deliver such material and equipment, and, if necessary, and to the extent possible, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Interconnecting Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, either (i) in the case of overpayment, Interconnecting Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by the Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts, or (ii) in the case of underpayment, Interconnection Customer shall promptly pay such amounts still due plus any costs, including penalties incurred by Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which the Interconnecting Transmission Owner has incurred expenses and has not been reimbursed by the Interconnection Customer.

2.4.2 Interconnecting Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Interconnecting Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, Interconnection Service shall terminate and, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Interconnecting Transmission Owner's Interconnection Facilities. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from a non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party(ies) pursuant to this

LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

3.1 **Filing**. The ~~System Operator and~~ Interconnecting Transmission Owner shall jointly file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required, in accordance with Section 11.3 of the LGIP. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the ~~System Operator and~~ Interconnecting Transmission Owner with respect to such filing and to provide any information reasonably requested by the ~~System Operator and/or the~~ Interconnecting Transmission Owner needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

~~**4.1 Interconnection Product Options.** Interconnection Customer has selected the following (checked) type(s) of Interconnection Service:~~

4.1 Reserved.

~~Check: ____ NR for NR Interconnection Service (NR Capability Only)~~

~~____ CNR for CNR Interconnection Service (CNR Capability and NR Capability)~~

~~**4.1.1 Capacity Network Resource Interconnection Service (CNR Interconnection Service).**~~

~~**4.1.1.1 The Product**. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and the Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Large Generating Facility in a manner comparable to that in~~

~~which all other Capacity Network Resources are interconnected under the CNR Interconnection Standard. CNR Interconnection Service allows the Interconnection Customer's Large Generating Facility to be designated as a Capacity Network Resource, to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the net CNR Capability, or as otherwise provided in Market Rule 1, Section III of the Tariff, on the same basis as all other existing Capacity Network Resources, and to be studied as a Capacity Network Resource on the assumption that such a designation will occur.~~

~~4.1.2 Network Resource Interconnection Service (NR Interconnection Service).~~

~~4.1.2.1 The Product~~~~. The System Operator and Interconnecting Transmission Owner must conduct the necessary studies and Interconnecting Transmission Owner and Affected Parties must construct the Network Upgrades needed to interconnect the Large Generating Facility in a manner comparable to that in which all other Network Resources are interconnected under the NC Interconnection Standard. NC Interconnection Service allows the Interconnection Customer's Large Generating Facility to participate in the New England Markets, in accordance with Market Rule 1, Section III of the Tariff, up to the gross and net NR Capability or as otherwise provided in Market Rule l, Section III of the Tariff. Notwithstanding the above, the portion of a Large Generating Facility that has been designated as a Network Resource interconnected under the NC Interconnection Standard cannot be a capacity resource under Section III.13 of the Tariff, unless pursuant to a new Interconnection Request for CNR Interconnection Service.~~

4.2 Provision of Service. ~~System Operator and~~ Interconnecting Transmission Owner shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the LGIA and ~~System Operator, in conjunction with the~~ Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.

4.4 **No Transmission Delivery Service**. The execution of this LGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

~~**4.5** **Transmission Delivery Service Implications**. CNR Interconnection Service and NR Interconnection Service allow the Interconnection Customer's Large Generating Facility to be designated by any Network Customer under the Tariff on the New England Transmission System as a Capacity Network Resource or Network Resource, up to the net CNR Capability or NR Capability, respectively, on the same basis as all other existing Capacity Network Resources and Network Resources interconnected to the New England Transmission System, and to be studied as a Capacity Network Resource or a Network Resource on the assumption that such a designation will occur. Although CNR Interconnection Service and NR Interconnection Service do not convey a reservation of transmission service, any Network Customer can utilize its network service under the Tariff to obtain delivery of capability from the Interconnection Customer's Large Generating Facility in the same manner as it accesses Capacity Network Resources and Network Resources. A Large Generating Facility receiving CNR Interconnection Service or NR Interconnection Service may also be used to provide Ancillary Services, in accordance with the Tariff and Market Rule 1, after technical studies and/or periodic analyses are performed with respect to the Large Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Capacity Network Resource or Network Resource. However, if an Interconnection Customer's Large Generating Facility has not been designated as a Capacity Network Resource or as a Network Resource by any load, it cannot be required~~

~~to provide Ancillary Services except to the extent such requirements extend to all Generating Facilities that are similarly situated.~~

4.5 Reserved.

~~CNR Interconnection Service and NR Interconnection Service do not necessarily provide the Interconnection Customer with the capability to physically deliver the output of its Large Generating Facility to any particular load on the New England Transmission System without incurring congestion costs. In the event of transmission constraints on the New England Transmission System, the Interconnection Customer's Large Generating Facility shall be subject to the applicable congestion management procedures for the New England Transmission System in the same manner as other Capacity Network Resources or Network Resources.~~

~~There is no requirement either at the time of study or interconnection, or at any point in the future, that the Interconnection Customer's Large Generating Facility be designated as a Capacity Network Resource or as a Network Resource by a Network Service Customer under the Tariff or that the Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Large Generating Facility as either a Capacity Network Resource or a Network Resource, it must do so pursuant to the Tariff.~~

~~Once an Interconnection Customer satisfies the requirements for obtaining CNR Interconnection Service or NR Interconnection Service, as long as the Large Generating Facility has not been deemed to be retired, any future transmission service request for delivery from the Large Generating Facility on the New England Transmission System of any amount of capacity capability and/or energy capability will not require that any additional studies be performed or that any further upgrades associated with such Large Generating Facility be undertaken, regardless of whether or not such Large Generating Facility is ever designated by a Network Customer as a Capacity Network Resource or Network Resource, and regardless of changes in ownership of the Large Generating Facility. To the extent the Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Large Generating Facility outside the New England Transmission System, or if the unit has been deemed to be retired, such~~

~~request may require additional studies and upgrades in order for Interconnecting Transmission Owner to grant such request.~~

4.6 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.4. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 **Options**. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall specify the In-Service Date, Initial Synchronization Date, and Commercial Operation Date as specified in the Interconnection Request or as subsequently revised pursuant to Section 4.4 of the LGIP; and select either Standard Option or Alternate Option set forth below for completion of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as set forth in Appendix A, and such dates and selected option shall be set forth in Appendix B (Milestones). In accordance with Section 8 of the LGIP and unless otherwise mutually agreed, the Alternate Option is not an available option if the Interconnection Customer waived the Interconnection Facilities Study.

5.1.1 **Standard Option**. The Interconnecting Transmission Owner shall design, procure, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B (Milestones). The Interconnecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Interconnecting Transmission Owner reasonably expects that it will not be able to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the specified dates, the Interconnecting Transmission Owner shall promptly provide written notice to the Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 **Alternate Option**. If the dates designated by Interconnection Customer are acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities by the designated dates.

If Interconnecting Transmission Owner subsequently fails to complete Interconnecting Transmission Owner's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B (Milestones); Interconnecting Transmission Owner shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable System Operator refuses to grant clearances to install equipment.

5.1.3 Option to Build. If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. The System Operator, Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as deemed appropriate by System Operator in accordance with applicable codes of conduct and confidentiality requirements must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A to the LGIA. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the Interconnection Customer elects not to exercise its option under Article 5.1.3 (Option to Build), Interconnection Customer shall so notify Interconnecting Transmission Owner within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection

Customer) pursuant to which Interconnecting Transmission Owner is responsible for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Interconnecting Transmission Owner shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades pursuant to 5.1.1 (Standard Option).

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Interconnecting Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Interconnecting Transmission Owner would be subject in the engineering, procurement or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Interconnecting Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Interconnecting Transmission Owner a schedule for construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Interconnecting Transmission Owner;

(5) at any time during construction, Interconnecting Transmission Owner shall have the right to gain unrestricted access to the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Interconnecting Transmission Owner, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the Interconnecting Transmission Owner for claims arising from the Interconnection Customer's construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 (Indemnity);

(8) the Interconnection Customer shall transfer control of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the Interconnecting Transmission Owner;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Interconnecting Transmission Owner;

(10) Interconnecting Transmission Owner shall approve and accept for operation and maintenance the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Interconnecting Transmission Owner "as built" drawings, information, and any other documents that are reasonably required by Interconnecting Transmission Owner to assure that the Interconnection Facilities and Stand Alone Network

Upgrades are built to the standards and specifications required by Interconnecting Transmission Owner.

5.3 Liquidated Damages. The actual damages to the Interconnection Customer, in the event the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Interconnecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Interconnecting Transmission Owner to the Interconnection Customer in the event that Interconnecting Transmission Owner does not complete any portion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Interconnecting Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which the Interconnecting Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Interconnecting Transmission Owner to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Interconnecting Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless the Interconnection Customer would have been able to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Interconnecting Transmission Owner's delay; (2) the Interconnecting Transmission Owner's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with the Interconnecting Transmission Owner or any cause beyond Interconnecting Transmission Owner's reasonable control or reasonable ability to cure, including, but not limited to, actions by the System Operator that cause delays and/or delays in licensing, permitting or consents where the Interconnecting Transmission Owner has pursued such licenses, permits or consents in good faith; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 **Power System Stabilizers**. If a Power System Stabilizer is required to be installed on the Large Generating Facility for the purpose of maintaining system stability, the Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the System Operator and Interconnecting Transmission Owner, and consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator and Interconnecting Transmission Owner reserve the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the System Operator and Interconnecting Transmission Owner, or their designated representative. The requirements of this paragraph shall not apply to non-synchronous power production equipment.

5.5 **Equipment Procurement**. If responsibility for construction of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by the Interconnecting Transmission Owner, then the Interconnecting Transmission Owner shall commence design of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The Interconnecting Transmission Owner has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 The Interconnecting Transmission Owner has received written authorization to proceed with design and procurement from the Interconnection Customer by the date specified in Appendix B (Milestones); and

5.5.3 The Interconnection Customer has provided security to the Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.6 **Construction Commencement**. The Interconnecting Transmission Owner shall commence construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades;

5.6.3 The Interconnecting Transmission Owner has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B (Milestones); and

5.6.4 The Interconnection Customer has provided security to Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.7 Work Progress. The Interconnection Customer and the Interconnecting Transmission Owner shall keep each Party informed, by written quarterly progress reports, as to the progress of their respective design, procurement and construction efforts in order to meet the dates specified in Appendix B (Milestones). Any Party may also, at any other time, request a written progress report from the other Parties. If, at any time, the Interconnection Customer determines that the completion of the Interconnecting Transmission Owner's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer~~, upon the System Operator's approval that the change in the In-Service Date will not constitute a Material Modification pursuant to Section 4.4 of the LGIP,~~ will provide written notice to the Interconnecting Transmission Owner of such later date upon which the completion of the Interconnecting Transmission Owner's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the New England Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, ~~System Operator and~~ the Interconnecting Transmission Owner shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. System Operator and Interconnecting Transmission Owner shall permit Interconnection Customer to operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ("ICIF"). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.10.1 Large Generating Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Interconnecting Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Interconnecting Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Interconnecting Transmission Owner's Review. Interconnecting Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Interconnecting Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Interconnecting Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facilities. The Interconnection Customer shall provide Interconnecting

Transmission Owner specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Interconnecting Transmission Owner's Interconnection Facilities Construction. The Interconnecting Transmission Owner's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnecting Transmission Owner shall deliver to the Interconnection Customer the following "as-built" drawings, information and documents for the Interconnecting Transmission Owner's Interconnection Facilities. The appropriate drawings and relay diagrams shall be included in Appendix A of this LGIA.

The System Operator will obtain operational control of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities pursuant to the TOA.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at the incremental cost to another Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents if allowed under the applicable agency agreement, that are necessary to enable the Access Party solely to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Administered Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the New England Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall at Interconnection Customer's expense use Reasonable Efforts, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property. Notwithstanding the foregoing, the Interconnecting Transmission Owner shall not be obligated to exercise eminent domain authority in a manner inconsistent with Applicable Laws and Regulations or when an Interconnection Customer is authorized under Applicable Laws and Regulations to exercise eminent domain on its own behalf.

5.14 Permits. ~~System Operator,~~ Interconnecting Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Interconnecting Transmission Owner shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Interconnecting Transmission Owner's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Interconnecting Transmission Owner to construct, and Interconnecting Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Administered Transmission System, which are included in the Base Case of the Facilities Study for the Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date. The Interconnection Customer shall reimburse the Interconnecting Transmission Owner for all costs incurred related to early construction to the extent such costs are not recovered from other Interconnection Customers included in the base case.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Interconnecting Transmission Owner and System Operator, to suspend at any time all work by Interconnecting Transmission Owner associated with the construction and installation of Interconnecting

Transmission Owner's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that the New England Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and the System Operator's and Interconnecting Transmission Owner's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Interconnecting Transmission Owner (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the New England Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Interconnecting Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Interconnecting Transmission Owner shall obtain Interconnection Customer's authorization to do so. Interconnecting Transmission Owner shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Interconnecting Transmission Owner required under this LGIA pursuant to this Article 5.16, and has not requested Interconnecting Transmission Owner to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Interconnecting Transmission Owner and System Operator, if no effective date is specified. A suspension under this Article 5.16 does not automatically permit an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date. A request for extension of such dates is subject to Section 4.4.5 of the LGIP. Notwithstanding the extensions permitted under Section 4.4.5 of the LGIP, the three-year period shall in no way result in an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date that exceeds seven (7) years from the date of the Interconnection Request; otherwise, this LGIA shall be deemed terminated.

5.17 Taxes.

5.17.1 Payments Not Taxable. The Parties intend that all payments or property transfers made by any Party for the installation of the Interconnecting Transmission Owner's

Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the New England Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Interconnecting Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Interconnecting Transmission Owner's request, Interconnection Customer shall provide Interconnecting Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Interconnecting Transmission Owner represents and covenants that the cost of the Interconnecting Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon Interconnecting Transmission Owner. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Interconnecting Transmission

Owner from the cost consequences of any current tax liability imposed against Interconnecting Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Interconnecting Transmission Owner.

The Interconnecting Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Interconnecting Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Interconnecting Transmission Owner to report payments or property as income subject to taxation; provided, however, that Interconnecting Transmission Owner may require Interconnection Customer to provide security, in a form reasonably acceptable to Interconnecting Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Interconnecting Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Interconnecting Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period, and the applicable statute of limitation, as it may be extended by the Interconnecting Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Interconnecting Transmission Owner, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Interconnecting Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Interconnecting Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Interconnecting Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).For this purpose, (i) Current Taxes shall be computed based on Interconnecting Transmission Owner composite federal and state tax rates at the time the payments or property transfers are received and Interconnecting Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Interconnecting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Interconnecting Transmission Owner current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Interconnecting Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Interconnecting Transmission Owner under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Interconnecting Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Interconnecting Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Interconnecting Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within ten (10) years from the date on which the relevant Interconnecting Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenant contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Interconnecting Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Interconnecting Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Interconnecting Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Interconnecting Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Interconnecting Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Interconnecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Interconnecting Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Interconnecting Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Interconnecting Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Interconnecting Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Interconnecting Transmission Owner for the tax at issue in the contest.

5.17.8 Refund. In the event that (a) a private letter ruling is issued to Interconnecting Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Interconnecting Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not taxable to Interconnecting Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Interconnecting Transmission Owner are not subject to federal income tax, or (d) if Interconnecting Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Interconnecting Transmission Owner pursuant to this LGIA, Interconnecting Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Interconnecting Transmission Owner for such taxes which Interconnecting Transmission Owner did not submit to the taxing authority, interest calculated in accordance with the methodology set forth in the Commission's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Interconnecting Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Interconnecting Transmission Owner, any refund or credit Interconnecting Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Interconnecting Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Interconnecting Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Interconnecting Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Interconnecting Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Interconnecting Transmission Owner's Interconnection Facilities.

The intent of this provision is to leave Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network

Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Interconnecting Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Interconnecting Transmission Owner for which Interconnection Customer may be required to reimburse Interconnecting Transmission Owner under the terms of this LGIA. Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, Interconnecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Interconnecting Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Interconnecting Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Interconnecting Transmission Owner.

5.18 Tax Status. Each Party shall cooperate with the others to maintain the other Party's(ies') tax status. Nothing in this LGIA is intended to adversely affect any Interconnecting Transmission Owner's tax-exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Interconnection Customer or Interconnecting Transmission Owner may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, the facilities of any Affected Parties, or the New England Transmission System, that Party shall provide to the other Parties and any Affected Party: (i) sufficient information regarding such modification so that the other Party(ies) may evaluate the potential impact of such modification prior to commencement of the work; and (ii) such information as may be required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party(ies) at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed. Notwithstanding the foregoing, no Party shall be obligated to proceed with a modification that would constitute a Material Modification and therefore require an Interconnection Request under the LGIP, except as provided under and pursuant to the LGIP.

In the case of Large Generating Facility or Interconnection Customer's Interconnection Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Interconnecting Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Interconnecting Transmission Owner makes to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System to facilitate the interconnection of a third party to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System, or to provide transmission service to a third party under the Tariff, except as provided for under the Tariff or any other applicable tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, the Interconnecting Transmission Owner shall test Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Interconnection Customer and Interconnecting Transmission Owner shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, as may be necessary to ensure the continued interconnection of the Large Generating Facility to the Administered Transmission System in a safe and reliable manner. The Interconnection Customer and Interconnecting Transmission Owner each shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's(ies') facilities, at the requesting Party's expense, as may be in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator shall also have the right to require reasonable additional testing of the other Party's (ies') facilities in accordance with the

ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

6.3 Right to Observe Testing. Each Party shall notify the System Operator and other Party(ies) in advance of its performance of tests of its Interconnection Facilities. The other Party(ies) has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's(ies') tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's(ies') System Protection Facilities and other protective equipment; and (iii) review the other Party's(ies') maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Each Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be governed by Article 22.

ARTICLE 7. METERING

7.1 General. Each Party shall comply with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding metering. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment. Unless the System Operator otherwise agrees, the Interconnection Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Tariff and to communicate the information to the System Operator. Unless otherwise agreed, such equipment shall remain the property of the Interconnecting Transmission Owner.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Interconnecting Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Interconnecting Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Interconnecting Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards and the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.4 Testing of Metering Equipment. Interconnecting Transmission Owner shall inspect and test all Interconnecting Transmission Owner-owned Metering Equipment upon installation and thereafter as specified in the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than the values specified within ISO New England Operating Documents, or successor documents, from the measurement made by the standard meter used in the test, the Interconnecting Transmission Owner shall adjust the measurements, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.5 **Metering Data.** At Interconnection Customer's expense, metered data shall be telemetered to one or more locations designated by System Operator and Interconnecting Transmission Owner. The hourly integrated metering, established in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, used to transmit Megawatt hour ("MWh") per hour data by electronic means and the Watt-hour meters equipped with kilowatt-hour ("kwh") or MWh registers to be read at month's end shall be the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection. Instantaneous metering is required for all Generators in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 8. COMMUNICATIONS

8.1 **Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with the System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.2 **Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer or Interconnecting Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by System Operator and Interconnecting Transmission Owner through use of a dedicated point-to-point data circuit(s). The communication protocol for the data circuit(s) shall be specified by System Operator and Interconnecting Transmission Owner. All information required by the ISO New England

Operating Documents, or successor documents, must be telemetered directly to the location(s) specified by System Operator and Interconnecting Transmission Owner.

Each Party will promptly advise the other Party(ies) if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party(ies). The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 **No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 **Provision of Data from an Intermittent Power Resource.** The Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall provide meteorological and forced outage data to the System Operator to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The Interconnection Customer with an Intermittent Power Resource having wind as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with an Intermittent Power Resource having solar as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The System Operator and Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power product forecast. The Interconnection Customer whose Generating Facility is an Intermittent Power Resource also shall submit data to the System Operator regarding all forced outages to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the System Operator, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Intermittent Power Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the System Operator. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

ARTICLE 9. OPERATIONS

9.1 **General.** Each Party shall comply with applicable provisions of ISO New England Operating Documents, Reliability Standards, or successor documents, regarding operations. Each Party shall provide to the other Party(ies) all information that may reasonably be required by the other Party(ies) to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 **Control Area Notification.** Before Initial Synchronization Date, the Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner in writing in accordance with ISO New England Operating Documents, Reliability Standards, or successor documents. If the Interconnection Customer elects to have the Large Generating Facility dispatched and operated from a remote Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs and ISO New England Operating Documents, Reliability Standards, or successor documents, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area for dispatch and operations.

9.3 **Interconnecting Transmission Owner and System Operator Obligations.** Interconnecting Transmission Owner and System Operator shall cause the Interconnecting Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Reliability Standards, or successor documents. Interconnecting Transmission Owner or System Operator may provide operating instructions to Interconnection Customer consistent with this LGIA, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Interconnecting Transmission Owner's and System Operator's operating protocols and procedures as they may change from time to time. Interconnecting Transmission Owner and

System Operator will consider changes to their operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.5 Start-Up and Synchronization. The Interconnection Customer is responsible for the proper start-up and synchronization of the Large Generating Facility to the New England Transmission System in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility and all generating units comprising the Large Generating Facility, as applicable, to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis and in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The requirements of this paragraph shall not apply to wind generators.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized the Large Generating Facility to the New England Transmission System, Interconnection Customer shall operate the Large Generating Facility at the direction of System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding voltage schedules in accordance with such requirements.

9.6.2.1 Voltage Regulators. The Interconnection Customer must keep and maintain a voltage regulator on all generating units comprising a Large Generating Facility in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. All Interconnection Customers that have, or are required to have, automatic voltage regulation shall normally operate the Large Generating Facility with its voltage regulators in automatic operation.

It is the responsibility of the Interconnection Customer to maintain the voltage regulator in good operating condition and promptly report to the System Operator and Interconnecting Transmission Owner any problems that could cause interference with its proper operation.

9.6.2.2 Governor Control. The Interconnection Customer is obligated to provide and maintain a functioning governor on all generating units comprising the Large Generating Facility in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6.2.3 System Protection. The Interconnection Customer shall install and maintain protection systems in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6.3 Payment for Reactive Power.

Interconnection Customers shall be compensated for Reactive Power service in accordance with Schedule 2 of the Section II of the Tariff.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. The System Operator shall have the authority to coordinate facility outages in accordance with the ISO New England

Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's(ies') facilities as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.1.2 Outage Schedules. Outage scheduling, and any related compensation, shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.2 Interruption of Service. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the System Operator or Interconnecting Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect System Operator's or Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.

9.7.3 Under-Frequency and Over Frequency Conditions. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with System Operator and Interconnecting Transmission Owner in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall install at Interconnection Customer's expense, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, any System Protection Facilities that may be required on the Interconnecting Transmission Owner Interconnection Facilities or the New England Transmission System as a result of the interconnection of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.4 Each Party's protective relay design shall allow for tests required in Article 6.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.5 Requirements for Protection. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and compliance with Good Utility Practice , Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the New England Transmission System not otherwise isolated by Interconnecting Transmission

Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the New England Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the New England Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the New England Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. A Party's facilities shall not cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party(ies) with a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Administered Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Interconnecting Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Commission for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the New England Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 10. MAINTENANCE

10.1 Interconnecting Transmission Owner and Customer Obligations. Interconnecting Transmission Owner and Interconnection Customer shall each maintain that portion of its respective facilities that are part of the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

10.2 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Interconnecting Transmission Owner's Interconnection Facilities, Stand Alone Network Upgrades, Network Upgrades and Distribution Upgrades.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer's Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at its sole expense.

11.2 Interconnecting Transmission Owner's Interconnection Facilities. Interconnecting Transmission Owner shall design, procure, construct, install, own and/or control the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Interconnecting Transmission Owner shall design, procure, construct, install, and own the Network Upgrades, and to the extent provided by Article 5.1, Stand Alone Network Upgrades, and Distribution Upgrades described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades). The Interconnection

Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Interconnecting Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Cost Allocation; Compensation; Rights; Affected Systems

11.4.1 Cost Allocation. Cost allocation of Generator Interconnection Related Upgrades shall be in accordance with Schedule 11 of Section II of the Tariff.

11.4.2 Compensation. Any compensation due to the Interconnection Customer for increases in transfer capability to the PTF resulting from its Generator Interconnection Related Upgrade shall be determined in accordance with Sections II and III of the Tariff.

11.4.3 Rights. Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades.

11.4.4 Special Provisions for Affected Systems. The Interconnection Customer shall enter into separate related facilities agreements to address any upgrades to the Affected System(s) that are necessary for safe and reliable interconnection of the Interconnection Customer's Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of an Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Interconnecting Transmission Owner a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Interconnecting Transmission Owner in accordance with Section 7 of Schedule 11 of the Tariff. In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Interconnecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If System Operator or Interconnecting Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.4.1 of this LGIA, Interconnection Customer shall be compensated pursuant to the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Interconnection Customer shall be compensated for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the New England Transmission System during an Emergency Condition in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 12. INVOICE

12.1 General. Each Party shall submit to the other Party(ies), on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party(ies) under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades, Interconnecting Transmission Owner shall provide an invoice of the final cost of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnecting Transmission Owner shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Interconnection Customer shall pay to Interconnecting Transmission Owner any amount by which the actual payment by Interconnection Customer for estimated costs falls short of the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by any Party will not constitute a waiver of any rights or claims the other Party(ies) may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Interconnecting Transmission Owner and Interconnection Customer, Interconnecting Transmission Owner shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Interconnecting Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Interconnecting Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in the Commission's Regulations at 18 CFR § 35.19a(a)(2)(iii).

ARTICLE 13. EMERGENCIES

13.1 Obligations. Each Party shall comply with the Emergency Condition procedures of the System Operator in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

13.2 Notice. Interconnecting Transmission Owner or System Operator as applicable shall notify Interconnection Customer and System Operator or Interconnecting Transmission Owner as applicable, promptly when it becomes aware of an Emergency Condition that affects the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Interconnecting Transmission Owner and System Operator promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Interconnecting Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

13.3 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Interconnecting Transmission Owner~~ and System Operator~~, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by the Interconnecting Transmission Owner or ~~the System Operator or ~~otherwise regarding the New England Transmission System.

13.4 System Operator's and Interconnecting Transmission Owner's Authority.

13.4.1 General. System Operator or Interconnecting Transmission Owner may take whatever actions or inactions with regard to the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the New England Transmission System or Interconnecting Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. System Operator and Interconnecting Transmission Owner may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.4.2; directing the Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of System Operator's and Interconnecting Transmission Owner's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.4.2 Reduction and Disconnection. System Operator and Interconnecting Transmission Owner may reduce Interconnection Service or disconnect the Large Generating Facility or the Interconnection Customer's Interconnection Facilities when such reduction or disconnection is necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. These rights are separate and distinct from any right of curtailment of the System Operator and

Interconnecting Transmission Owner pursuant to the Tariff. When the System Operator and Interconnecting Transmission Owner can schedule the reduction or disconnection in advance, System Operator and Interconnecting Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. System Operator and Interconnecting Transmission Owner shall coordinate with the Interconnection Customer in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the System Operator and Interconnecting Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the New England Transmission System to their normal operating state as soon as practicable in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

13.5 Interconnection Customer Authority. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents and the LGIA and the LGIP, the Interconnection Customer may take whatever actions or inactions with regard to the Large Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities. System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.6 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, a Party shall not be liable to another Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended. To the extent that a condition arises that could result in Interconnection Customer's inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978, the Parties shall engage in good faith negotiations to address the condition so that such result will not occur and so that this LGIA can be performed.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by a Party to another Party and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F (Addresses for Delivery of Notices and Billings).

A Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another Party and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party(ies) in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 A Party shall not be considered to be in Default with respect to any obligation hereunder (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party(ies) in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default.

17.1.1 General. No Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party(ies). Upon a Breach, the non-Breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the non-Breaching

Party(ies) shall have the right to terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this LGIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which they are entitled at law or in equity. The provisions of this Article will survive termination of this LGIA.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

Notwithstanding any other provision of this Agreement, the liability, indemnification and insurance provisions of the Transmission Operating Agreement ("TOA") or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission Owner and the liability, indemnification and insurance provisions of the Tariff apply to the relationship between the ~~System Operator and the Interconnection Customer and between the~~ Interconnecting Transmission Owner and the Interconnection Customer.

18.1 Indemnity. Each Party shall at all times indemnify, defend, and save the other Party(ies) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's(ies') action or inactions of their obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by an indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in which event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 **Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall a Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 **Insurance.** The Interconnecting Transmission Owner and the Interconnection Customer shall, at their own expense, maintain in force throughout the period of this LGIA, and until released by the other Party(ies), the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death, and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party(ies), its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program, provided that such Party's senior secured debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article, it shall notify the other Party(ies) that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

ARTICLE 19. ASSIGNMENT

19.1 **Assignment.** This LGIA may be assigned by any Party only with the written consent of the other Parties; provided that the Parties may assign this LGIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA;

and provided further that the Interconnection Customer shall have the right to assign this LGIA, without the consent of the Interconnecting Transmission Owner or System Operator, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Interconnection Customer will promptly notify the Interconnecting Transmission Owner and System Operator of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Interconnecting Transmission Owner and System Operator of the date and particulars of any such exercise of assignment right(s), including providing the Interconnecting Transmission Owner with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Interconnecting Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality. Confidential Information shall include, without limitation, all information governed by the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by a Party, the other Party(ies) shall provide, in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of

Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party(ies) that it no longer is confidential.

22.1.3 Release of Confidential Information. A Party shall not release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party(ies). The disclosure by each Party to the other Party(ies) of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. By providing Confidential Information, a Party does not make any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, a Party does not obligate itself to provide any particular information or Confidential Information to the other Party(ies) nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use

Confidential Information solely to fulfill its obligations to the other Party(ies) under this LGIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party(ies) with prompt notice of such request(s) or requirement(s) so that the other Party(ies) may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party(ies), use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party(ies)) or return to the other Party(ies), without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party(ies).

22.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's(ies') Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party(ies) shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Parties shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 **Disclosure to the Commission, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR. section 1b.20, if the Commission or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to the Commission or its staff, within the time provided for in the request for information. In providing the information to the Commission or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this LGIA prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Party(ies) to the LGIA when it is notified by the Commission or its staff that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party(ies) to any person not employed or retained by the other Party(ies), except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party(ies), such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party(ies) in writing of the information it claims is confidential. Prior to any disclosures of the other Parties' Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party(ies) in writing and agrees to assert confidentiality and cooperate with the other Party(ies) in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Party(ies), first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party(ies). The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four (24) hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party(ies) copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 **Information Acquisition.** Subject to any applicable confidentiality restrictions, including, but not limited to, codes of conduct, each Party shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 **Information Submission by ~~System Operator and~~ Interconnecting Transmission Owner.** The initial information submission by ~~System Operator and~~ Interconnecting Transmission Owner shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date and shall include information necessary to allow the Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise mutually agreed to by the Parties. On a monthly basis Interconnecting Transmission Owner shall provide Interconnection Customer a status report on the construction and installation of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Interconnecting Transmission Owner and System Operator for the Interconnection Feasibility Study, Interconnection System Impact Study and Interconnection Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Interconnecting Transmission Owner ~~and System Operator~~ standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is different from what was originally provided to Interconnecting Transmission Owner pursuant to the Interconnection Study Agreement between Interconnecting Transmission Owner and Interconnection Customer, then the ~~System Operator~~Interconnecting Transmission Owner will review it and conduct appropriate studies, as needed, at the Interconnection Customer's cost, to determine the impact on the New England Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Commercial Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information and "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to the Interconnecting Transmission Owner for each individual generating unit in a station.

The Interconnection Customer shall provide the Interconnecting Transmission Owner ~~and System Operator~~ with any information changes due to proposed equipment replacement, repair, or adjustment. Interconnecting Transmission Owner shall provide the Interconnection Customer ~~and System Operator~~ with any information changes due to proposed equipment replacement, repair or adjustment in the directly connected substation or any adjacent Interconnecting Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information in accordance with Article 5.19 of this Agreement.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Party(ies) to: (i) verify the costs incurred by the disclosing Party for which the other Party(ies) are responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party(ies) when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory Breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party(ies), to audit at its own expense the other Party's(ies') accounts and records pertaining to a Party's performance or a Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's(ies') costs, calculation of invoiced amounts, the efforts to allocate responsibility for the provision of reactive support to the New England Transmission System, the efforts to allocate responsibility for interruption or reduction of generation on the New England Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four (24) months following Interconnecting Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four (24) months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party(ies) together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party(ies) for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 Submission. In the event a Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party(ies) with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party(ies). In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's(ies') receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The ~~arbitrator so~~arbitrators chosen by the ~~System Operator~~Parties shall select a third member who shall chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable Commission regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 **Costs.** Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) a pro rata share of the cost of a single arbitrator chosen by the Parties.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 **General.** Each Party makes the following representations, warranties and covenants:

28.1.1 **Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 **Authority.** Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 **No Conflict.** The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

ARTICLE 29. [OMITTED]

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect. This LGIA and the rights and obligations hereof shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix of this LGIA, or such Section of the LGIP or such Appendix of the LGIP, as the case may be; (6)

"hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

30.4 Entire Agreement. Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, this LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. Except for the ISO New England Operating Documents, Applicable Reliability Standards, any applicable tariffs, related facilities agreements, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this LGIA. Termination or Default of this LGIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Interconnecting Transmission Owner. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. Consistent with Section 11.3 of the LGIP, Interconnecting Transmission Owner ~~and System Operator~~ shall have the right to make unilateral filings with the Commission to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Parties and to participate fully in any proceeding before the Commission in which such modifications may be considered. In the event of disagreement on terms and conditions of the LGIA related to the costs of upgrades to such Interconnecting Transmission Owner's transmission facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of Interconnecting Transmission Owner, and any provisions related to physical impacts of the interconnection on Interconnecting Transmission Owner's transmission facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to Interconnecting Transmission Owner's position on such terms and conditions. Nothing in this LGIA shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

IN WITNESS WHEREOF, the Parties have executed this LGIA in triplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

~~**ISO New England Inc. (System Operator)**~~

~~By:~~

~~Title:~~

~~Date:~~

~~[*Insert Name of*]~~New England Power Company (Interconnecting Transmission Owner)

By: Will L Malee

William L. Malee

Title: Director, Transmission Commercial & Authorized Representative

Date: 16 July 2014

~~[*Insert name of*]~~Deepwater Block Island Wind, LLC (Interconnection Customer)

By: Jeffrey [illegible]

Title: CFO

Date: 7/16/14

APPENDICES TO LGIA

APPENDIX A TO LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

The Interconnection Facilities, Network Upgrades and Distribution Upgrades discussed below will be engineered, designed, constructed, owned, and maintained by a combination of the Interconnecting Transmission Owner, Interconnecting Transmission Owner's Affiliate: The Narragansett Electric Company ("TNECO"), and the Interconnection Customer, as specified below. Any reference to "Affiliate" below is specifically a reference to TNECO. It is acknowledged that the Interconnecting Transmission Owner will be responsible for coordinating with Interconnecting Transmission Owner's Affiliate as necessary to meet its obligations under this Agreement. It is further acknowledged by the Parties that Interconnecting Transmission Owner's Affiliate will own and maintain certain facilities identified under this Agreement, (hereafter, the "Interconnecting Transmission Owner's Affiliate Interconnection Facilities").

1. Interconnection Facilities:

a. **Point of Interconnection and Point of Change of Ownership**. ~~The Point of Interconnection shall be at the point where [*insert description of location*]. See Appendix A-[*insert*], which drawing is attached hereto and made part hereof.~~

The Point of Interconnection shall be the "Delivery Point" as defined in the Power Purchase Agreement executed between Interconnecting Transmission Owner's Affiliate and Interconnection Customer on June 30, 2010, as the same may be amended and/or restated from time to time (the "Power Purchase Agreement"), which shall be the point at which the Interconnection Facilities connect to the low voltage side of Interconnecting Transmission Owner's Affiliate's substation, which is to be constructed on Block Island ("Block Island Substation").

The Point of Change of Ownership shall be the point at which the terrestrial cable, which shall be owned by Interconnecting Transmission Owner's Affiliate, shall terminate in

Interconnection Customer's transition vault, located at Block Island Town Beach on Block Island, and shall be spliced with Interconnection Customer's submarine cable.

The metering point shall be located at the Point of Interconnection.

The Point of Interconnection, the Point of Change of Ownership ~~shall be at~~and the metering point ~~where *[insert description of location]*. See~~are shown in Appendix A-~~-[*insert*]~~1, which drawing is attached hereto and made part hereof. This is a preliminary drawing for the purposes of illustrating the general arrangement of the interconnection. Additional details will be established in the Protection Philosophy to be established by the Parties.

~~If not located at the Point of Interconnection, the metering point(s) shall be located at: [*insert location*].~~

b. **Interconnection Customer's Interconnection Facilities (including metering equipment)**. ~~The Interconnection Customer shall construct [*insert Interconnection Customer's Interconnection Facilities*]. See Appendix A-[*insert*].~~

The Interconnection Customer shall design to Interconnecting Transmission Owner's specifications, construct, own, operate, and maintain a 34.5kV undersea cable system from the wind farm in Block Island Sound to Block Island Town Beach, including the splices to the Interconnecting Transmission Owner's Affiliate's portions of the underground power cable, fiber optic cables, and neutral/ground continuity conductor in the transition vault at the beach, and certain data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment, as needed, located within a separate building in the Block Island substation (the "Interconnection Customer's Control Building"), as shown in the one-line diagram attached as Appendix A-1 and the general arrangement diagram attached as Appendix A-2.

Upon notification to Interconnecting Transmission Owner's Affiliate's control room, Interconnecting Transmission Owner's Affiliate shall allow Interconnection Customer (or an independent Person mutually acceptable to the Parties) access to the Block Island Substation for the purpose of facilitating Interconnection Customer's execution of its rights and obligations as set forth in Section 4.7 of the Power Purchase Agreement, including but not limited to the inspection, testing, calibration and audit of Interconnection Customer's revenue meter. Interconnection Customer shall have the right to install an additional check meter.

The Parties agree that Interconnection Customer's cost responsibility for the Direct Assignment Facilities, described in Section 4(A) of Appendix C to this LGIA, shall satisfy all of the Interconnection Customer's obligations to engineer, procure, provide, construct install, own, keep, operate or maintain any equipment, systems, rights of use, licenses, rights of way and easements in connection with this agreement, including but not limited to those obligations set forth in Sections 5.13, 5.19, 6.1, 8.2, 9.4, 9.7.4, 9.7.5, 10.2 and Appendix C.3.B of the LGIA. Direct Assignment Facilities shall have the meaning set forth in the Tariff.

c. **Interconnecting Transmission Owner's Interconnection Facilities (including metering equipment)**.

~~c.~~ The Interconnecting Transmission ~~Owner~~Owner's Affiliate shall design, construct ~~[*insert*~~, own, operate and maintain the following equipment, at Interconnection Customer's expense, which collectively constitute the Interconnecting Transmission Owner's Affiliate Interconnection Facilities~~]. See Appendix [*insert*].~~, i.e. the Direct Assignment Facilities: (1) a 34.5kV breaker and associated substation equipment as shown in Appendix A-1 and in Appendix A-2, (2) a 34.5kV grounding transformer, (3) an 34.5kV overhead circuit across the property upon which the substation is to be located, and (4) an underground cable system along a public way from the substation property to the Interconnection Customer's transition vault to be located at the Block Island Town Beach.

The Direct Assignment Facilities constitute all of Interconnecting Transmission Owner's Affiliate Interconnection Facilities.

The Interconnecting Transmission Owner will not design, construct, own, operate and maintain any equipment.

2. **Network Upgrades**:

a. **Stand Alone Network Upgrades**. ~~[*insert Stand Alone Network Upgrades*]~~None.

b. **Other Network Upgrades**. ~~[*insert Other Network Upgrades*]~~None.

3. **Distribution Upgrades**. ~~[*insert Distribution Upgrades*]~~None

4. **Affected System Upgrades**. ~~[insert Affected System Upgrades]~~None.

5. **Contingency Upgrades List**:

a. **Long Lead Facility-Related Upgrades.** Not Applicable.

The Interconnection Customer's Large Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

~~[*insert list of upgrades*]~~
None

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this LGIA in accordance with Article 17.1, and the System Operator will initiate all necessary steps to terminate this LGIA, in accordance with Article 2.3.

b. Other Contingency Upgrades. ~~[*e.g.*, list of upgrades associated with higher queued Interconnection Requests with LGIAs prior to this LGIA and any other contingency upgrades that the Parties may deem necessary for the interconnection of the Large Generating Facility.]~~None.

6. Post-Forward Capacity Auction Re-study Upgrade Obligations. ~~[*insert any change in upgrade obligations that result from re-study conducted post receiving a Capacity Supply Obligation through a Forward Capacity Auction.*]~~To be determined

APPENDIX A-1 TO LGIA: ONE-LINE DIAGRAM

[this page to be substituted for the one-line diagram found in Attachment A Clean Tariff submitted with this filing]

APPENDIX A-2 TO LGIA: GENERAL ARRANGEMENT DIAGRAM

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[this page to be substituted for the diagram found in Attachment A Clean Tariff submitted with this filing]

APPENDIX B TO LGIA

Milestones

1. **Selected Option Pursuant to Article 5.1:** Interconnection Customer selects the ~~[*insert*]~~5.1.1 Standard Option. Options ~~as~~ described in Articles ~~5.1.[*insert*], 5.1.[*insert*], and 5.1.[*insert*]~~5.1.2, 5.1.3 and 5.1.4 shall not apply to this LGIA.

2. **Milestones and Other Requirements for all Large Generating Facilities:** The description and entries listed in the following table establish the required Milestones in accordance with the provisions of the LGIP and this LGIA. The referenced section of the LGIP or article of the LGIA should be reviewed by each Party to understand the requirements of each milestone.

Item No.	Milestone Description	Responsible Party	Date	LGIP/LGIA Reference
1	Provide evidence of continued Site Control to System Operator, or $250,000 non-refundable deposit to Interconnecting Transmission Owner	Interconnection Customer	~~Within 15 BD of final LGIA receipt~~Completed	§ 11.3.1.1 of LGIP
2	Provide evidence of one or more milestones specified in § 11.3 of LGIP	Interconnection Customer	~~Within 15 BD of final LGIA receipt~~Complete, Purchase Power Agreement executed on June 30, 2010	§ 11.3.1.2 of LGIP
3	Commit to a schedule for payment of upgrades	Interconnection Customer	~~Within 15 BD~~Completed upon execution of ~~final~~the LGIA ~~receipt~~. See Milestone 8.	§ 11.3.1.2 of LGIP

4	Provide either (1) evidence of Major Permits or (2) refundable deposit to Interconnecting Transmission Owner	Interconnection Customer	~~If (1) Within 15 BD of final LGIA receipt or if (2) At time of LGIA execution~~Completed	§ 11.3.1.2 of LGIP
5	Provide certificate of insurance	Interconnection Customer and Interconnecting Transmission Owner	Within ten (10~~-Calendar~~) days ~~of~~following execution of this LGIA	§ 18.3.9 of LGIA
6	Provide siting approval for Generating Facility and Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	~~As may be agreed to~~ By ~~the Parties~~September 1, 2014	§ 7.5 of LGIP
7A	Receive Governmental Authority approval for any facilities requiring regulatory approval	Interconnection Customer ~~and/or Interconnecting Transmission Owner~~	~~If needed, as may be agreed to by the Parties~~By September 1, 2014	§ 5.6.1 of LGIA
7B	Obtain necessary real property rights and rights-of-way for the construction of ~~a discrete aspect of~~ the Interconnecting Transmission Owner's Affiliate Interconnection Facilities ~~and Network Upgrades~~	~~Interconnection Customer and/or~~ Interconnecting Transmission Owner	~~If needed, as may be agreed to by the Parties~~By September 1, 2014	§ 5.6.2 of LGIA

7C	Provide to Interconnecting Transmission Owner written authorization to proceed with ~~design,~~:	Interconnection Customer	~~As may be agreed to by the Parties~~	§ 5.5.2 and § 5.6.3 of LGIA
7C.1	pre-design			
7C.2	design,		Upon execution of this Agreement*	
7C.3	equipment procurement		By September 1, 2014*.	
7.C.4	and construction		By December 1, 2014*.	
			By March 1, 2015*.	
7D	Provide quarterly written progress reports	Interconnection Customer and Interconnecting Transmission Owner	15 Calendar Days after the end of each quarter beginning the quarter that includes the date for Milestone 7C and ending ~~when~~upon completion of the ~~entire~~ Large Generating Facility and ~~all required~~ Interconnection Facilities ~~and Network Upgrades are in place~~	§ 5.7 of LGIA
8	Provision of Security to	Interconnection	~~At least 30 Calendar~~	§§ 5.5.3 and

	Interconnecting Transmission Owner pursuant to Section 11.5 of LGIA	Customer	~~Days prior to design, procurement and construction~~pre design pre-payment due by September 1, 2014. Remaining Pre-payments due with written authorizations from Milestone 7C	5.6.4 of LGIA
9	Provision of Security Associated with Tax Liability to Interconnecting Transmission Owner pursuant to Section 5.17.3 of LGIA	Interconnection Customer	~~As may be agreed to by the Parties~~Within 30 days after final invoice (Milestone 22)	§ 5.17.3 of LGIA
10	Commit to the ordering of long lead time material for Interconnection Facilities ~~and Network Upgrades~~	Interconnection Customer	~~As may be agreed to by the Parties~~N/A	§ 7.5 of LGIP
11A	Provide initial design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	~~180 Calendar Days prior to Initial Synchronization Date~~By September 1, 2014	§ 5.10.1 of LGIA § 7.5 of LGIP
11B	Provide comments on initial design,	Interconnecting Transmission	Within 30 Calendar Days of receipt	§ 5.10.1 of LGIA

	engineering and specification for Interconnection Customer's Interconnection Facilities	Owner		§ 7.5 of LGIP
12A	Provide final design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner	Interconnection Customer	~~90 Calendar Days prior to Initial Synchronization Date~~By December 1, 2014	§ 5.10.1 of LGIA § 7.5 of LGIP
12B	Provide comments on final design, engineering and specification for Interconnection Customer's Interconnection Facilities	Interconnecting Transmission Owner	Within 30 Calendar Days of receipt	§ 5.10.1 of LGIA § 7.5 of LGIP
13	Deliver to Transmission Owner "as built" drawings, information and documents regarding Interconnection Customer's Interconnection Facilities	Interconnection Customer	Within 120 Calendar Days of Commercial Operation date	§ 5.10.3 of LGIA
14	Provide protective relay settings to Interconnecting Transmission Owner for coordination and verification	Interconnection Customer	~~At least 90 Calendar Days prior to Initial Synchronization Date~~By March 1, 2015	§§ 5.10.1 of LGIA
15	Commencement of	Interconnecting	~~As may be agreed to~~	§ 5.6 of LGIA

	construction of Interconnection Facilities	Transmission Owner	~~by the Parties~~30 days after receipt of written authorization to proceed by Interconnection Customer	
16	Submit updated data "as purchased"	Interconnection Customer	No later than 180 Calendar Days prior to Initial Synchronization Date	§ 24.3 of LGIA
17	In Service Date	Interconnection Customer	~~Same as Interconnection Request unless subsequently modified~~By June 1 , 2016	§ 3.3.1 and 4.4.5 of LGIP, § 5.1 of LGIA
18	Initial Synchronization Date	Interconnection Customer	~~Same as Interconnection Request unless subsequently modified~~By November 1, 2016	§ 3.3.1, 4.4.4, 4.4.5, and 7.5 of LGIP
19	Submit supplemental and/or updated data – "as built/as-tested"	Interconnection Customer	Prior to Commercial Operation Date	§ 24.4 of LGIA
20	Commercial Operation Date	Interconnection Customer	~~Same as Interconnection Request unless subsequently modified~~By December 31, 2016	§ 3.3.1, 4.4.4, 4.4.5, and 7.5 of LGIP
21	Deliver to Interconnection	Interconnecting Transmission	~~If requested,~~ Within 120 ~~Calendar~~ days	§ 5.11 of LGIA

	Customer "as built" drawings, information and documents regarding Interconnecting Transmission Owner's Interconnection Facilities	Owner	~~after~~of Commercial Operation Date	
22	Provide Interconnection Customer final cost invoices	Interconnecting Transmission Owner	Within 6 months of completion of construction of Interconnecting Transmission Owner Affiliate Interconnection Facilities ~~and Network Upgrades~~	§ 12.2 of LGIA

* See Appendix C, Table 3 – Summary of Prepayments

3. **Milestones Applicable Solely for ~~CNR Interconnection Service and~~ Long Lead Facility Treatment.** In addition to the Milestones above, the following Milestones apply to Interconnection Customers requesting ~~CNR Interconnection Service and/or~~ Long Lead Facility Treatment: None.

~~Item No.~~	~~Milestone Description~~	~~Responsible Party~~	~~Date~~	~~LGIP/LGIA Reference~~
~~1~~	~~If Long Lead Facility, all dates by which Critical Path Schedule upgrades will be submitted to System Operator (end date for New Capacity Show of Interest Submission)~~	~~Interconnection Customer~~		~~§ 3.2.3 of LGIP~~
~~2~~	~~If Long Lead Facility, dates by which~~	~~Interconnection~~		~~§ 3.2.3 of LGIP~~

	~~Long Lead Facility Deposits will be provided to System Operator (each deadline for which New Generating Capacity Resource would be required to provide financial assurance under § III.13.1.9 of the Tariff)~~	~~Customer~~		
~~3~~	~~If Long Lead Facility, Capacity Commitment Period (not to exceed the Commercial Operation Date)~~	~~Interconnection Customer~~		~~§ 1 and 3.2 of LGIP~~
~~4~~	~~Submit necessary requests for participation in the Forward Capacity Auction associated with the Generating Facility's requested Commercial Operation Date, in accordance with Section III.13 of the Tariff~~	~~Interconnection Customer~~		~~§ 3.2.1.3 of LGIP~~
~~5~~	~~Participate in a CNR Group Study~~	~~Interconnection Customer~~		~~§ 3.2.1.3 of LGIP~~
~~6~~	~~Qualify and receive a Capacity Supply Obligation in accordance with Section III.13 of the Tariff~~	~~Interconnection Customer~~		~~§ 3.2.1.3 of LGIP~~

APPENDIX C TO LGIA

Interconnection Details

1. Description of Interconnection:

Interconnection Customer shall install a ~~[*insert*]~~30 MW Large Generating Facility, rated at ~~[*insert*]~~30 MW gross and ~~[*insert*]~~29 MW net, with all studies performed at or below these outputs, and will be located in Block Island Sound, Rhode Island. The Generating Facility is comprised of ~~[*insert*] units in a [*insert description of facility type – combined cycle, wind farm, etc.*]~~five (5) fully-inverted wind turbine generators connected in series and rated at~~: [*insert*]~~ 6.0 MW each~~, and will located at [*insert location*]~~. The Parties agree that the inverter controls in each wind turbine generator shall satisfy the Generator Governor requirement set forth in Section 9.6.2.2 of this LGIA.

The Large Generating Facility shall receive:

~~Network Resource~~ Interconnection Service ~~for the NR Capability~~ at a level not to exceed ~~[*insert*~~30 MW gross and ~~*net*]~~29 MW net for Summer~~,~~ and ~~[*insert*~~30 MW gross and ~~*net*]~~29 MW net for Winter.

~~Capacity Network Resource Interconnection Service for: (i) the NR Capability at a level not to exceed [*insert gross and net at or above 50 degrees F*] MW for Summer and [*insert gross and net at or above 0 degrees F*] MW for Winter; and (ii) the CNR Capability at [*insert net*] MW for Summer and [*insert net*] MW for Winter, which shall not exceed [*insert the maximum net MW electrical output of the Generating Facility at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter*.] The CNR Capability shall be the highest amount of the Capacity Supply Obligation obtained by the Generating Facility in accordance with Section III.13 of the Tariff and, if applicable, as specified in filings by the System Operator with the Commission pursuant to Section III.13 of the Tariff.~~

2. Detailed Description of Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	5
Manufacturer	Alstom or comparable
Model	SWT 6.0-154 or comparable
Designation of Generator(s)	Haliade -150
Excitation System Manufacturer	Alstom Inverter Technology
Excitation System Model	Alstom Inverter Technology
Voltage Regulator Manufacturer	Alstom Inverter Technology
Voltage Regulator Model	Alstom Inverter Technology
Generator Ratings	

Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 90 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 50 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 20 Degrees F	6.0/5.9
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above zero Degrees F	6.0/5.9
Station Service Load For Each Unit	.1 MW + j .075 MVAR
Overexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • PF = ±0.90 (at 34.5kV)
Underexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • • PF = ±0.90 (at 34.5kV)
Generator Short Circuit and Stability Data	
Generator MVA rating	6.5MVA– inverter technology
Generator AC Resistance	Inverter Technology 0.724 (0 …20ms) 99999 (LVRT ... ∞) *See Note Below
Subtransient Reactance (saturated)	Programmed – inverter technology
Subtransient Reactance (unsaturated)	Programmed – inverter technology
Transient Reactance (saturated)	Programmed – inverter technology
Negative sequence reactance	Programmed – inverter technology
Generator Step-up Transformer Data	
Number of units	5
Self Cooled Rating	6.5MVA
Maximum Rating	6.5MVA
Winding Connection (LV/HV)	0.9kV/34.5kV
Fixed Taps	±2 x 2.5%

Z1 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Positive Sequence X/R ratio primary to secondary Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Z0 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Project Grounding Transformer Data	
Number of units	1
Self Cooled Rating	n.a.
Maximum Rating	1.5 MVA @ 10 sec
Winding Connection (LV/LV/HV)	
Fixed Taps	none
Z1 primary to secondary at self cooled rating	Consistent with Section 3.E below
Positive Sequence X/R ratio primary to secondary	Consistent with Section 3.E below
Z0 primary to secondary at self cooled rating	Consistent with Section 3.E below

*Note: These are typical characteristic data for synchronous machines. Converter based wind turbines depend heavily in the converter control for the maximum currents and stability analysis.
An equivalence (to obtain the synchronous machine parameters) has been performed with the maximum short circuit currents from the converters in 100% voltage dip considering that the short circuit has 3 steps: a subtransient from the dip until 20ms, a transient between 20 ms until the LVRT (aprox. 150ms) and the steady-state value from the LVRT to the end of simulation.

3. Meteorological and Forced Outage Data Requirements for a Generating Facility that is an Intermittent Power Resource:

An Interconnection Customer whose Generating Facility is an Intermittent Power Resource having wind as the energy resource (referred to here in as "Wind Plant") will be required to provide the following meteorological and forced outage data to the System Operator in the manner specified in the ISO New England Operating Documents. Capitalized terms in this Appendix C.3 that are not defined in Section 1 of the Agreement shall have the meanings specified in the ISO New England Operating Documents.

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A. Static Plant Data

Below are the static plant data requirements that describe the physical layout of the Wind Plant and any associated meteorological equipment as well as data relevant to the design and operation of the Wind Plant. The static plant data must be supplied to the System Operator in the manner specified in the ISO New England Operating Documents. The Interconnection Customer must keep the static plant data current and must inform the System Operator of any proposed datapoints changes.

1) Wind Plant:

a) Wind Turbine tower center coordinates (i.e., latitude and longitude in WGS84 DD-MM-SS.SS using GPS WAAS, or comparable, methodology) and ground elevation of turbines (in meters, to one decimal place).

b) Number of turbines.

c) Turbine model(s) including IEC wind class.

d) Density dependent turbine nominal power curves for each type of turbine in the plant for standard test conditions (e.g., air density equaling 1.225 kg/m^3) and for three additional values of density (for which the density values must be supplied): one power curve for normal operation at the long-term average density expected for the plant and one power curve each for normal operation at approximately 85% (+/-10%) and approximately 115% (+/-10%), respectively of the expected long-term average Wind Plant air density.

e) Hub height(s) (in meters to one decimal place).

f) Maximum plant nameplate capacity (in MW to two decimal places).

g) Cut-in wind speed(s) and time constants (if any, e.g., windspeed must be above 3.4 m/s for at least 5 minutes, etc.).

h) Cut-out wind speed(s) and time constants (if any).

i) Cut back in wind speed(s) and time constants (if any).

j) Cold temperature cutoff threshold(s) (in Degrees C to one decimal place).

k) High temperature cutoff threshold(s) (in Degrees C to one decimal place).

l) Any cold weather operation packages and their effects on wind turbine operational envelope (e.g. blade and/or gearbox heaters, etc. that extends cold temperature cut-out to below xx degrees, etc.).

m) Wind turbine icing behavior:

i. Triggers for icing related shutdowns (e.g., temperatures, relative humidities, out-of-balance conditions, etc.).

ii. Triggers for release from icing related shutdowns (e.g., manual reset, temperatures, hysteresis, etc.).

n) For all plant wind speed and direction measuring devices (i.e., nacelle-level wind measuring devices):

i. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights) and calibration curves and/or reports.

ii. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data and the mitigation measures employed (e.g., diagram of location with respect to the nacelle and rotor).

o) Descriptions of any permitting or administrative restrictions such as requirements to reduce or to cease power production during certain hours or during certain events or wind conditions.

p) For model training purposes, any available historical information required by the wind power forecaster regarding plant power output, plant meteorological conditions, and conditions that may have caused power output to be below theoretical maximum power output given the experienced wind speeds may also be required to be provided.

2) Met gathering station(s):

a. Center of structure(s) coordinates (using the same method listed above for turbine in the Wind Plant) and ground elevation of met station(s).

b. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights).

c. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data (e.g., met-tower dimensions and profile) and the mitigation measures employed (e.g. mounting arm dimensions and orientations).

B. Real-Time Data

Below is the real-time operational and meteorological data requirements for Wind Plant operators that must be provided to the System Operator. The real-time operational and meteorological data must be electronically and automatically transmitted to the System Operator over a secure network using the protocol specified in the ISO New England Operating Documents. This information is required with a high degree of accuracy and reliability.

1) Availability:

The Wind Plant operator's real-time data transfer process and data gathering equipment shall be designated to operate at all times.

2) Required Data:

a) At a minimum, nacelle-level wind speed and wind direction measurements must be provided from the highest wind turbine (i.e., wind turbine hub elevation in terms of elevation above mean sea level) and a minimum of one wind turbine at the maximal value of each of the four true cardinal directions (i.e., the farthest true North, South, East, and West) in each Wind Turbine Group within the plant. Additionally, the wind turbine nearest the capacity-weighted centroid of the Wind Plant must also report wind speeds and directions. If any wind turbine within a Wind Turbine Group satisfies more than one of these conditions then it may be used to fulfill all conditions that it satisfies (e.g., if the highest wind turbine in a Wind Turbine Group is also the farthest North and the farthest East, it may be used to supply data for all three of these categories). Where more than one turbine satisfies these conditions, preference should be given to those turbines that will be least affected by Wind Plant wake effect from the prevailing wind direction(s). Finally, where a Wind Turbine Group contains 10 or less wind turbines only the nacelle-level data from the highest wind turbine nacelle is required. The locations of wind turbines with nacelle-level equipment providing data must be referenced to the Static Plant Data supplied locations.

b) Ambient temperature, air pressure and relative humidity must be measured, at a minimum, at one location within the plant (preferably as near to the capacity-weighted centroid of the Wind Plant as possible) whose height above ground may be in the range of 2 m to 10 m (or up to 30 m above mean sea level for offshore Wind Plants) and the measurement height above ground (or mean sea level for offshore Wind Plants) must be stated to within 10 cm.

3) Frequency

Minimum frequencies of the real-time data Wind Plant operators must provide are specified in the ISO New England Operating Documents.

C. Outage Coordination

Wind Plants shall submit daily outages in advance to perform routine maintenance work, which in many cases may have no effect on their overall MW capability. Therefore:

1) All Wind Plants must submit Wind Plant Future Availability to the System Operator.

2) If the Wind Plant does not have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, and is not a Qualified Generator Reactive Resource, only Wind Plant Future Availability must be reported to the System Operator.

3) Any Wind Plant that does have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, or that is a Qualified Generator Reactive Resource, must report Wind Plant Future Availability, and also submit an outage request to the System Operator only when the outage will

derate the plant to the point that the available nameplate is less than its Capacity Supply Obligation and/or Qualfied VARs.

4. Other Description of Interconnection Plan and Facilities:

~~[*Insert any other description relating to the Generating Facility, including, but not limited to switchyard, protection equipment, step-up transformer to the extent not described in Appendix A.*]~~**A. Studies**

1. Interconnection Feasibility Study: N/A.
2. Interconnection System Impact Study: Completed: Q405 System Impact Study – March 2014;; On April 16, 2014, the Proposed Plan Application received Reliability Committee recommendation for approval by the System Operator.
3. Interconnection Facilities Study: Waived
4. Optional Interconnection Study: None
5. Supplemental System Impact Study: None

B. Interconnection Customer's Interconnection Facilities.

The Interconnection Customer will own the Interconnection Customer's Interconnection Facilities described in Appendix A.1.b to this Agreement.

The Interconnection Customer will engineer, procure, install, own and maintain the telemetering (RTU) equipment and the telecommunication circuits that are installed at the Block Island Substation and which are necessary to interface and communicate with the System Operator Communications Front End (CFE) network and the Interconnecting Transmission Owner's Local Control Center. Once the RTU has been configured by the Interconnection Customer, the Interconnecting Transmission Owner will check the reporting of the Interconnection Customer RTU to ensure that it is sending the appropriate signals to the Local Control Center. ISO-NE will check the RTU telemetry and control signals as required according to the ISO-NE CFE Interface specifications.

Interconnecting Transmission Owner and Interconnecting Transmission Owner's Affiliate agree to work with the Interconnection Customer and landowner to obtain adequate physical space and the necessary rights of use, rights of way and easements within the Block Island Substation for Interconnection Customer to safely and conveniently install, operate and maintain such data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment as are agreed by the Interconnection Customer and Interconnecting Transmission Owner for the safe and reliable operations of the Generating Facility, which equipment shall be located within the Interconnection Customer's Control Building, as identified in Appendix A-2. Interconnecting Transmission Owner's Affiliate shall be responsible for all site preparation and civil works for such space as part of the Direct Assignment Facilities, but shall have no responsibility for the construction of Interconnection Customer's Control Building or the equipment therein.

Properly accredited representatives of the Interconnecting Transmission Owner shall at all reasonable times have access to the Interconnection Customer's Interconnection Facilities at the transition structure to make reasonable inspections and obtain information required in connection with this Agreement.

Upon notice to the Interconnection Transmission Owner Affiliate's control room, properly accredited representatives of the Interconnection Customer shall at all reasonable times have access to the Interconnection Facilities to make reasonable inspections and obtain information required in connection with this Agreement.

C. Interconnecting Transmission Owner's Interconnection Facilities

The Interconnecting Transmission Owner will own, operate and maintain the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A.1.c to this Agreement at the Interconnection Customer's expense.

Interconnecting Transmission Owner's Affiliate will own, operate and maintain the Interconnecting Transmission Owner's Affiliate's Interconnection Facilities described in Appendix A.1.c to this Agreement, at the Interconnection Customer's expense.

D. Testing

Testing of the Interconnection Facilities shall be performed by Interconnection Customer. Prior to conducting the tests, Interconnection Customer shall submit the proposed testing protocols to the Interconnecting Transmission Owner's Affiliate. The Interconnecting Transmission Owner's Affiliate shall have the right to review and comment on such proposed testing protocols (the "Test Protocols"). Within ten (10) days after receipt of the Test Protocols from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Protocols or (B) reject the Test Protocols by providing written notice stating the reasons for the rejection and specifying the changes necessary to make the Test Protocols acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Protocols within ten (10) days, then Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Protocols as originally submitted by Interconnection Customer.

At least five (5) days prior to conducting the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate, and Interconnecting Transmission Owner's Affiliate prior to shall have the right to witness the tests.

Following the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate of the results of the tests (the "Test Results"). Within ten (10) days after receipt of the Test Results from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Results or (B) object to the Test Results by providing written notice stating the reasons for the rejection and specifying its objections and the changes necessary to make the Test Results acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Results within ten (10) days, then Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Results.

E. Protection Philosophy

Interconnection Transmission Owner and Interconnection Customer shall jointly establish a Protection Philosophy in compliance with Sections 9.6.2.3, 9.7.3, 9.7.4.1, 9.7.4.5 and 9.7.5 of this LGIA which shall be the design basis for the final engineering of the

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Interconnection Facilities. National Grid Connection Specifications ESB-756 shall be the prevailing guideline for interconnection and protection design development.

4. Special Conditions

A. Cost Responsibility

1. General

Pursuant to the terms of the Agreement, the Interconnection Customer shall be solely responsible for all reasonable costs incurred by the Interconnecting Transmission Owner and its Affiliate as a result of the Direct Assignment Facilities and/or services provided under this Agreement in excess of the estimated costs and charges provided in this Appendix C to this Agreement that are not otherwise recovered under the Tariff.

Such costs are intended to be recovered by, but would not be limited to, the charges specified below.

Interconnection Facilities

The Interconnection Customer shall be responsible for direct assignment facilities charges calculated in accordance with the formulae set forth in Schedule 21 – NEP, Attachment DAF of the OATT as may be in effect from time to time ("DAF Charge"). A copy of the presently effective transmission DAF Charge is provided in Appendix C, Exhibit 1 for illustrative purposes. Estimated Annual DAF Charges are provided in Appendix C, Table 1.

Metering and Related Equipment

The Interconnection Customer will own the revenue meter. The Interconnecting Transmission Owner's Affiliate will own and maintain the appropriate metering transformers, associated test switches, and a remote terminal unit ("RTU") and related equipment. Metering equipment must conform to Tariff and Operating Procedures in effect and amended from time to time, and will be subject to the requirements of the Interconnecting Transmission Owner. The Interconnecting

Transmission Owner shall be present during commissioning of the revenue meter and shall have the right to witness any testing of said meter. The Interconnection Customer grants permission to Interconnecting Transmission Owner's personnel from various departments including engineering, distribution planning, transmission planning and T&D, to access any and all Interconnection Customer RTU data which is telemetered to Interconnecting Transmission Owner's control room. Interconnecting Transmission Owner agrees not to share this data with its sales and marketing personnel pursuant to applicable FERC rules and regulations. Additionally, the Interconnecting Transmission Owner agrees not to share this data with anyone other than those listed above without the prior written consent of an officer of the Interconnection Customer.

If, at any time, any metering equipment is found to be inaccurate by the requirements set forth in ISO New England Operating Procedure No. 18 - Metering and Telemetering Criteria, Interconnecting Transmission Owner shall cause such metering equipment to be made accurate or replaced, and meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the preceding month shall be made except by agreement of the Interconnection Customer and Interconnecting Transmission Owner.

The Interconnecting Transmission Owner and Interconnection Customer shall comply with any reasonable request of the other concerning the sealing of the meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Generating Facility. If either Interconnecting Transmission Owner or Interconnection Customer believes that there has been a meter failure or stoppage, it shall immediately notify the other.

B. Termination Charge

In addition to the payment obligations specified in Article 2 of this Agreement for termination by the Interconnection Customer prior to the expiration of the term of this Agreement, the Interconnection Customer agrees that it will be responsible for the DAF Charges for the original term of this Agreement as determined in accordance with the formula set forth in Schedule 21 – NEP, Attachment DAF of the OATT or as contained in an alternative cost recovery mechanism that the FERC may have approved at the time of the termination.

The Interconnection Customer reserves its right to initiate or participate in a proceeding before the FERC to contest the reasonableness of the above charges.

C. Station Service

Interconnection Customer shall be responsible for properly arranging its Station Service electric requirements, including, auxiliary service or backup service.

D. Regulatory Compliance

The Parties agrees to provide each other with notices and copies of all filings, including any applicable FERC filings pertaining to the Interconnection Facilities and/or this Agreement.

E. Radial Service

Interconnection Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Interconnecting Transmission Owner's Affiliate Wakefield Substation and that there will be an interruption to interconnection service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable. Interconnecting Transmission Owner or its Affiliate will notify Interconnection Customer of any planned interruption in service prior to such interruption and of any unplanned interruption as soon as reasonably practicable.

F. Losses

The metering equipment shall be compensated internally in order to record the delivery of electricity in a manner that accounts for any energy losses occurring between the Metering Point and the Point of Interconnection both when the Large Generating Facility is delivering energy to the Point of Interconnection and when Station Service power is delivered to the Point of Interconnection for the benefit of the Interconnection Customer, consistent with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents or procedures.

G. Payment Schedule and Financial Security Requirements

Interconnection Customer shall make prepayments to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnecting Transmission Owner's Affiliate Interconnection Facilities by wire transfer in immediately available funds in accordance with the payment schedule in Appendix C, Table 3 of this Agreement.

1. The Summary Table of Prepayments as shown in Appendix C, Table 3 sets forth four (4) prepayments ("Prepayments").

2. The sum of the four prepayments made by Interconnection Customer shall be referred to as the "Total Estimated Cost". Within six (6) months following the In-Service Date, Interconnecting Transmission Owner shall inform Interconnection Customer of the final actual costs to design and install the Interconnecting Transmission Owner's Interconnection Facilities and Interconnecting Transmission Owner's Affiliate Interconnection Facilities ("Final Actual Installed Cost"), plus the actual tax gross up amount, as calculated by the Interconnecting Transmission Owner in accordance with the formula described in Article 5.17.4 of this Agreement ("Actual Tax Gross Up Amount") and shall provide Interconnection Customer with a final written invoice ("Final Invoice") for the difference between the Final Actual Installed Cost and the Total Estimated Cost ("Final Balance").

On or before thirty (30) days following the date of the Interconnecting Transmission Owner's Final Invoice, the Interconnection Customer shall pay the Final Balance to Interconnecting Transmission Owner by wire transfer in immediately available funds; provided that, subject to compliance with Article 12.2 of this Agreement, in the event that the Total Estimated Cost exceeds the Final Actual Installed Cost, any such excess amount shall be refunded to Interconnection Customer as an overpayment.

3. The Interconnecting Transmission Owner shall not be obligated to commence and may not commence any of the tasks listed in Appendix B of this Agreement until (i) the Interconnecting Transmission Owner has received written notice from

Interconnection Customer to proceed with such tasks, and (ii) the Interconnecting Transmission Owner has received the Prepayment required under this Section G corresponding to such task listed in Appendix B.

4. The Interconnection Customer and Interconnecting Transmission Owner agree that the Final Actual Installed Cost shall be considered a construction advance for tax purposes except as otherwise provided in Article 5.17.5 of this Agreement. On or before the date that Interconnection Customer pays the Interconnecting Transmission Owner's Final Invoice, Interconnection Customer shall present to the Interconnecting Transmission Owner a Letter of Credit ("LOC"), in form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed, in a face amount representing the estimated tax gross up amount on the Final Actual Installed Cost. For purposes of this Agreement, the Actual Tax Gross Up Amount shall be the product of (i) the Final Actual Installed Cost and (ii) the Interconnecting Transmission Owner's or its Affiliate's tax gross up rate in existence at the In-Service Date as shown in Appendix C, Table 1 of this Agreement.

5. The Interconnection Customer shall be responsible for all costs associated with the LOC, including, without limitation, the costs of obtaining, maintaining and replacing such LOC and reimbursement of the LOC Bank (as such term is defined below). Each LOC shall be in a form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed. Each LOC shall be an irrevocable, unconditional, and transferable standby letter of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (the "LOC Bank") provided that the Interconnection Customer is not an affiliate of the LOC Bank, the LOC Bank has at least ten billion dollars ($10,000,000,000) in assets and the LOC Bank's lowest credit rating is at least A2 from Moody's Investors Service or A from Standard and Poor's Ratings Services or Fitch, Inc. ("LOC Bank Requirement(s)"). If at any time (i) the LOC Bank fails to satisfy any LOC Bank Requirement, or (ii) the LOC Bank advises that it will not renew the LOC beyond its current expiration date ("Notice of Cancellation"), then, the Interconnection Customer shall deliver a replacement letter of credit from a bank meeting the LOC Bank Requirements and the other requirements of this Paragraph and this Agreement. Such replacement letter of credit shall be delivered to Interconnecting Transmission Owner

promptly but in no event later than ten (10) Calendar Days following the date on which the LOC Bank's first fails to satisfy an LOC Bank Requirement or, in the case of a Notice of Cancellation, thirty (30) Calendar Days prior to the current expiration date of the applicable LOC. If Interconnection Customer fails to provide such replacement LOC by the applicable date contemplated by this paragraph (and in compliance with the other requirements hereof), Interconnecting Transmission Owner shall have the immediate right to draw the full amount remaining under the applicable existing LOC.

6. Any LOC delivered pursuant to this Section G, as such LOC may be replaced, modified, or amended, from time to time, as contemplated above, shall serve as security for Interconnection Customer's obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under or in connection with this Agreement for the tax gross up on the cost of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, and Interconnecting Transmission Owner's Affiliate Interconnection Facilities and shall not be used for any other purpose.

7. Interconnection Customer shall maintain the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in full force and effect at all times; provided, however, that Interconnection Customer may terminate such LOC, any modification or amendment thereof, and any replacement for such LOC, only upon termination of Interconnection Customer's indemnification obligation in accordance with Article 5.17.3 of this Agreement. The Interconnecting Transmission Owner shall have the right to draw upon the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in the event the Interconnection Customer fails to timely meet any of its obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner or its Affiliate from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner or its Affiliate under or in connection with this Agreement, as well as any interest and penalties.

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8. If Interconnection Customer fails to make any payments required under this Appendix C or the Agreement, or fails to provide and maintain the security contemplated above, each in the form, amounts, and at the times, required, Interconnecting Transmission Owner or its Affiliate may exercise any rights, and pursue any remedies, available to it under this Agreement, including, without limitation, Article 12. If any payment date or other due date specified in this Section G falls on a weekend or a federal bank holiday, then such payment or due date shall be deemed to be the next business day.

APPENDIX C

EXHIBIT 1

Transmission DAF Charge

Monthly Rate Formula

The Monthly Rate shall equal the Annual Facilities Charge divided by 12.

The Annual Facilities Charge shall be calculated in a manner consistent with Schedule 21 - NEP, Attachment DAF of the OATT, determination of the Annual Facilities Charge for transmission facilities, which section of Schedule 21 currently provides as follows:

"The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility."

"The Gross Plant Investment shall be the investment from the plant accounting records associated with the facility."

"The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a)."

"To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I (B), and I. (C) of Attachment RR, Exhibit 1 of Schedule 21 - NEP."

"If the Interconnection Customer permanently terminates service in advance of the term of its Agreement, the Interconnection Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to Schedule 21 - NEP, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination."

"Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records."

APPENDIX C

Table 1 – Estimated Annual DAF Charges

The costs listed in this Appendix C, Table 1 are the estimates provided in Table 2 and are provided for illustrative purposes only. The DAF Charge will be adjusted to reflect the Final Actual Installed Cost and the Actual Annual Transmission Carrying Charges as determined from year to year. In the event that the Project is terminated, Interconnecting Transmission Owner shall refund to Interconnection Customer all Prepayments received in excess of Interconnecting Transmission Owner's expenses and payment obligations incurred in fulfillment of this Agreement.

Components	Estimated Cost
Pre-design*	$50,000
Design ITO Affiliate's Interconnection Facilities	$347,500
Procure ITO Affiliate's Interconnection Facilities	$662,500
Construct ITO Affiliate's Interconnection Facilities	$1,590,000
Estimated Total Customer Payments (see Tables 2 & 3)	$2,650,000
Tax Gross Up (0.3554[1] x Total Customer Payments)	$941,810

*A limited notice to proceed to be issued upon execution of this agreement will authorize initial expenditures not to exceed $50,000 and to be reimbursed no later than September 1, 2014.

Estimated Annual DAF Charge[2]	
Gross Plant Investment (w/out tax gross up)	$2, 650,000
Times	
Annual Carrying Charge Rate	7.48%
Equals	
Annual DAF Charge	$198,220

[1] The tax gross up rate shown in this Appendix C, Table 1 is the Interconnection Transmission Owner's 2009 tax gross up rate, which is subject to change. The Actual tax gross up rate will be the rate that is in existence at the In-Service Date.

[2] Annual DAF Charges are calculated by multiplying Year-end Gross Plant Investment (GPI) by the Annual Carrying Charge rate that is in effect at the time. The Annual Carrying Charge rate shown in this Appendix C, Table 1 is the 2011 rate and is provided for illustrative purposes only. The Interconnection Customer will pay the Annual DAF Charge on a monthly basis, which will be estimated as the Annual DAF Charges divided by 12. In no event shall the NEP DAF Charge be calculated on any basis different from the formula set forth in Schedule 21 – NEP, Attachment DAF of the OATT as may be in effect from time to time.

APPENDIX C

Table 2 – Estimated Cost of Interconnection Facilities for DAF Charges

Interconnection Facility	**Total Estimated Cost**	**% of Total**	**Interconnection Customer Cost**
34.5kV breaker at POI	$2,500,000*	20%	$500,000
Grounding transformer	$500,000	100%	$500,000
34.5kV overhead circuit	$300,000**	50%	$150,000
34.5kV underground circuit	$3, 000,000**	50%	$1,500,000
Total	$5,800,000		$2, 650,000

* Estimated cost of five breaker switchgear arrangement at Block Island Substation

** The Interconnection Customer is only responsible for the cost of the generator lead between the Point of Change of Ownership and the Point of Interconnection. A second 34.5kV line is for the tie of the Block Island Substation to the mainland, which is being funded outside of this Agreement. The two lines are running in parallel ductbanks from the shore and on common poles on the Block Island property. They were estimated together and a cost of one-half the total is used as a proxy cost for either line.

Table 3 – Summary Table of Prepayments

Date	**% of Total**	**Amount**
Milestones 8and7C2	**15%**	**$397,500**
Milestone 7C3	**25%**	**$662,500**
Milestone 7C4	**60%**	**$1,590,000**
Total		**$2,650,000**

APPENDIX D TO LGIA

Security Arrangements Details

Infrastructure security of the New England Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day New England Transmission System reliability and operational security. The Commission will expect System Operator, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected to the New England Transmission System to comply with the recommendations offered by the Critical Infrastructure Protection Committee and, eventually, best practice recommendations from NERC. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

APPENDIX E TO LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between System Operator, Interconnecting~~,~~ Transmission Owner and Interconnection Customer.

[*Date*]

New England Power Company
Attn: Director, Transmission Commercial
East Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

~~[*Interconnecting Transmission Owner; Address*]~~
~~[to be supplied]~~

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: ~~____________~~Block Island Wind Farm Large Generating Facility

Dear _______________:

On [Date] ~~[Interconnection Customer]~~Deepwater Block Island Wind, LLC has completed Trial Operation of Unit No. ___. This letter confirms that ~~[Interconnection Customer]~~Deepwater Block Island Wind, LLC commenced commercial operation of Unit No. ___ at the Large Generating Facility, effective as of [Date plus one day].

Thank you.

[*Signature*]

[*Interconnection Customer Representative*]

APPENDIX F TO LGIA

Addresses for Delivery of Notices and Billings Notices:

System Operator: N/A

~~Generator Interconnections~~

Interconnecting Transmission ~~Planning Department~~Owner:

~~ISO~~ New England ~~Inc.~~Power Company

Attn: Director, Transmission Commercial

West Wing, Floor 1

~~One Sullivan~~40 Sylvan Road

~~Holyoke~~Waltham, MA ~~01040-2841~~02451

With copy to:

~~Billing Department~~

~~ISO~~ New England ~~Inc.~~Power Company

Attn: Lead Account Manager

West Wing, Floor 1

~~One Sullivan~~40 Sylvan Road

~~Holyoke~~Waltham, MA ~~01040-2841~~02451

~~Interconnecting Transmission Owner:~~

~~*[To be supplied.]*~~

Interconnection Customer:

~~*[To be supplied.]*~~

Deepwater Block Island Wind, LLC

C/O Deepwater Wind, LLC

Attn: Chris van Beek, President

56 Exchange Terrace, Suite 101

Providence, RI 02903

Billings and Payments:

System Operator: N/A

~~Generator Interconnections~~

~~Transmission Planning Department~~

~~ISO New England Inc.~~

~~One Sullivan Road~~

~~Holyoke, MA 01040-2841~~

~~With copy to:~~

~~Billing Department~~

~~ISO New England Inc.~~

~~One Sullivan Road~~

~~Holyoke, MA 01040-2841~~

Interconnecting Transmission Owner:

New England Power Company

Attn: Transmission Billing

West Wing, Floor 2

40 Sylvan Road

Waltham, MA 02451

[~~*To be supplied*~~.]

Interconnection Customer:

[~~*To be supplied*~~.]

Deepwater Block Island Wind, LLC

C/O Deepwater Wind, LLC

Attn: Contract Admin

56 Exchange Terrace, Suite 101

Providence, RI 02903

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

-

System Operator: N/A

~~Facsimile: (413) 540-4203~~

~~E-mail: geninterconn@iso-ne.com~~

~~With copy to:~~

~~Facsimile: (413) 535-4024~~

~~E-mail: billingdept@iso-ne.com~~

Interconnecting Transmission Owner:

[~~*To be supplied*~~.]

Telephone: (781) 907-2409

Fax: (781) 296-8088

Email: edward.m.kremzier@nationalgrid.com

Interconnection Customer:

[~~*To be supplied*~~.]

Telephone: (401)-648-0606

Fax: (401)-228-8004

Email: kadmin@dwwind.com

DUNS Numbers:

Interconnection Customer: ~~[To be supplied]~~ 831810895

Interconnecting Transmission Owner: ~~[To be supplied]~~ 006952881

APPENDIX G TO LGIA

Interconnection Requirements For A Wind Generating Plant

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains

following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT. Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing

time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the System Operator and Interconnecting Transmission Owner, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind generating plant is in operation. Wind generating plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind generating plant shall provide SCADA capability to transmit data and receive instructions from the System Operator and Local Control Center to protect system reliability. The System Operator, Interconnecting Transmission Owner and the wind generating plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind generating plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

FERC rendition of the electronically filed tariff records in Docket No. ER14-02496-000
Filing Data:
CID: C001305
Filing Title: New England Power Filing of LGIA with Deepwater Block Island Wind, LLC
Company Filing Identifier: 159
Type of Filing Code: 10
Associated Filing Identifier:
Tariff Title: Service Agreements Under ISO-NE OATT Schedule 21-NEP
Tariff ID: 133
Payment Confirmation:
Suspension Motion:

Tariff Record Data:
Record Content Description, Tariff Record Title, Record Version Number, Option Code:
Deepwater LGIA, New England Power Co. Service Agmt. No. IA-NEP-26, 0.0.0, A
Record Narative Name:
Tariff Record ID: 11
Tariff Record Collation Value: 2000000   Tariff Record Parent Identifier: 0
Proposed Date: 2014-09-23
Priority Order: 500
Record Change Type: NEW
Record Content Type: 1
Associated Filing Identifier:

LARGE GENERATOR INTERCONNECTION AGREEMENT

BY AND BETWEEN

DEEPWATER BLOCK ISLAND WIND, LLC

AND

NEW ENGLAND POWER COMPANY d/b/a NATIONAL GRID

Issued by: William L. Malee
Director, Transmission Commercial Services
Authorized Representative

Effective Date: September 23, 2014

Issued on: July 24, 2014

LARGE GENERATOR INTERCONNECTION AGREEMENT

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THIS LARGE GENERATOR INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this 30th day of June 2014, by and between Deepwater Block Island Wind, LLC, a company organized and existing under the laws of the State of Delaware ("Interconnection Customer" with a Large Generating Facility), and New England Power Company d/b/a National Grid, a company organized and existing under the laws of the Commonwealth of Massachusetts ("Interconnecting Transmission Owner"). Under this Agreement the Interconnection Customer and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator") is the central dispatching agency provided for under the Transmission Operating Agreement ("TOA") which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the ISO New England Inc. Transmission, Markets and Services Tariff (Tariff); and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and

WHEREAS, Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified

in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the generator interconnection process provided for in Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under Schedule 22. Capitalized terms in this Agreement or Schedule 22 that are not defined in this Agreement shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of

any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Transmission System.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Parties.

At-Risk Expenditure shall mean money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Base Case shall have the meaning specified in Section 2.3 of the Large Generator Interconnection Procedures ("LGIP").

Base Case Data shall mean the Base Case power flow, short circuit, and stability data bases used for the Interconnection Studies by Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Standard Large Generator Interconnection Agreement.

Breaching Party shall mean a Party that is in Breach of the Standard Large Generator Interconnection Agreement.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Standard Large Generator Interconnection Agreement.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise. Confidential Information shall include, but not be limited to, information that is confidential pursuant to the ISO New England Information Policy.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Standard Large Generator Interconnection Agreement.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to

Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Standard Large Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by the Commission or if filed unexecuted, upon the date specified by the Commission.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission Owner, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or any Affected System to which the New England Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Standard Large Generator Interconnection Agreement to possess black start capability.

Engineering & Procurement ("E&P") Agreement shall mean an agreement that authorizes the Interconnection Customer, Interconnecting Transmission Owner and any other Affected Party to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§

791a *et seq.*

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer

reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner's Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner shall mean a Transmission Owner that owns, leases or otherwise possesses an interest in the portion of the Administered Transmission System at the Point of Interconnection and shall be a Party to the Standard Large Generator Interconnection Agreement. The term Interconnecting Transmission Owner shall not be read to include the System Operator.

Interconnecting Transmission Owner's Interconnection Facilities shall mean all facilities and equipment owned, controlled, or operated by Interconnecting Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Interconnecting Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Customer shall mean any entity, including a transmission owner or its Affiliates or subsidiaries, that interconnects or proposes to interconnect its Generating Facility with the Administered Transmission System under the Standard Large Generator Interconnection Procedures.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions

or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Interconnecting Transmission Owner, or a third party consultant for the Interconnection Customer to determine a list of facilities (including Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Administered Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Administered Transmission System, the scope of which is described in Section 6 of the Standard Large Generator Interconnection Procedures. The Interconnection Customer has the option to request either that the Interconnection Feasibility Study be completed as a separate and distinct study, or as part of the Interconnection System Impact Study. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the Standard Large Generator Interconnection Procedures for

conducting the Interconnection Feasibility Study.

Interconnection Request (a) shall mean an Interconnection Customer's request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to: (i) interconnect a new Generating Facility to the Administered Transmission System; (ii) increase the energy capability or capacity capability of an existing Generating Facility; (iii) make a Material Modification to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System; or (iv) commence participation in the wholesale markets by an existing Generating Facility that is interconnected with the Administered Transmission System. Interconnection Request shall not include: (i) a retail customer interconnecting a new Generating Facility that will produce electric energy to be consumed only on the retail customer's site; (ii) a request to interconnect a new Generating Facility to a distribution facility that is subject to the Tariff if the Generating Facility will not be used to make wholesale sales of electricity in interstate commerce; or (iii) a request to interconnect a Qualifying Facility (as defined by the Public Utility Regulatory Policies Act, as amended by the Energy Policy Act of 2005 and the regulations thereto), where the Qualifying Facility's owner intent is to sell 100% of the Qualifying Facility's output to its interconnected electric utility.

Interconnection Service shall mean the service provided by the Interconnecting Transmission Owner, associated with interconnecting the Interconnection Customer's Generating Facility to the Administered Transmission System and enabling the receipt of electric energy capability and/or capacity capability from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement and, if applicable, the Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, the Interconnection Facilities Study and the Optional Interconnection Study described in the Standard Large Generator Interconnection Procedures. Interconnection Study shall not include a CNR Group Study.

Interconnection Study Agreement shall mean any of the following agreements: the

Interconnection Feasibility Study Agreement, the Interconnection System Impact Study Agreement, the Interconnection Facilities Study Agreement, and the Optional Interconnection Study Agreement attached to the Standard Large Generator Interconnection Procedures.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Administered Transmission System and any other Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on Adverse System Impacts, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures. If the Interconnection Customer requests that the Interconnection Feasibility Study be completed as part of the Interconnection System Impact Study, Section 6 shall be performed as the first step of the Interconnection System Impact Study, and shall be regarded as part of the Interconnection System Impact Study. When the requirements of Section 6 are performed as part of the Interconnection System Impact Study, the Interconnection Customer shall be responsible only for the deposit requirements of the Interconnection System Impact Study, and there shall be only one final report, which will include the results of both Section 6 and Section 7.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the Standard Large Generator Interconnection Procedures for conducting the Interconnection System Impact Study.

IRS shall mean the Internal Revenue Service.

Large Generating Facility shall mean a Generating Facility having a maximum gross capability at or above zero degrees F of more than 20 MW.

Long Lead Time Generating Facility (“Long Lead Facility”) shall mean a Generating Facility with an Interconnection Request for CNR Interconnection Service that has, as applicable, elected or requested long lead time treatment and met the eligibility criteria and requirements specified in Section 3.2.3 of the LGIP.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Standard Large Generator Interconnection Agreement on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnifying Party.

Major Permits shall be as defined in Section III.13.1.1.2.2.2(a) of the Tariff.

Material Modification shall mean (i) except as expressly provided in Section 4.4.1, those modifications to the Interconnection Request, including any of the technical data provided by the Interconnection Customer in Attachment A to the Interconnection Request or to the interconnection configuration, requested by the Interconnection Customer that either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date; (ii) a change to the design or operating characteristics of an existing Generating Facility, including its Interconnection Facilities, that is interconnected with the Administered Transmission System that may have a significant adverse effect on the reliability or operating characteristics of the New England Transmission System; (iii) a delay to the Commercial Operation Date, In-Service Date, or Initial Synchronization Date of greater than three (3) years where the reason for delay is unrelated to construction schedules or permitting which delay is beyond the Interconnection Customer's control; or (iv) except as provided in Section 3.2.3.4 of the LGIP, a withdrawal of a request for Long Lead Facility treatment; or (v) except as provided in Section 3.2.3.6 of the LGIP, an election to participate in an earlier Forward Capacity Auction than originally anticipated.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Standard Large Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

Network Upgrades shall mean the additions, modifications, and upgrades to the New England Transmission System required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the Administered Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the Standard Large Generator Interconnection Agreement or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the Standard Large Generator Interconnection Procedures for conducting the Optional Interconnection Study.

Party shall mean the Interconnection Customer and Interconnecting Transmission Owner or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to Interconnecting Transmission Owner's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the Administered Transmission System.

Queue Position shall mean the order of a valid request in the New England Control Area, relative to all other pending requests in the New England Control Area, that is established based upon the date and time of receipt of such request by the System Operator.

Requests are comprised of Interconnection Requests, requests for Elective Transmission Upgrades, requests for transmission service and notification of requests for interconnection to other electric systems, as notified by the other electric systems, that impact the Administered Transmission System. For purposes of this LGIA, references to a "higher-queued" Interconnection Request shall mean one that has been received by the System Operator (and placed in queue order) earlier than another Interconnection Request, which is referred to as "lower-queued."

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affected Party as deemed appropriate by the System Operator in accordance with applicable codes of conduct and confidentiality requirements, conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (a) that the Interconnection Customer is the owner in fee simple of the real property for which new interconnection is sought; (b) that the Interconnection Customer holds a valid written leasehold interest in the real property for which new interconnection is sought; (c) that the Interconnection Customer holds a valid written option to purchase or leasehold property for which new interconnection is sought; (d) that the Interconnection Customer holds a duly executed written contract to purchase or leasehold the real property for which new interconnection is sought; or (e) that the Interconnection Customer has filed applications for required permits to site on federal or state property.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the

New England Transmission System during their construction. The Interconnection Customer and Interconnecting Transmission Owner, in accordance with applicable codes of conduct and confidentiality requirements, must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement ("LGIA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility, that is included in this Schedule 22 to the Tariff.

Standard Large Generator Interconnection Procedures ("LGIP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in this Schedule 22 to the Tariff.

System Protection Facilities shall mean the equipment, including necessary signal protection communications equipment, required to protect (1) the New England Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the New England Transmission System or on other delivery systems or other generating systems to which the New England Transmission System is directly connected.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

ARTICLE 2. EFFECTIVE DATE, TERM AND TERMINATION

2.1 Effective Date. This LGIA shall become effective upon execution by the Parties subject to acceptance by the Commission (if applicable), or if filed unexecuted, upon the date specified by the Commission. Interconnecting Transmission Owner, shall promptly and jointly file this LGIA with the Commission upon execution in accordance with Section 11.3 of the LGIP and Article 3.1, if required.

2.2 Term of Agreement. This LGIA, subject to the provisions of Article 2.3, and by mutual agreement of the Parties, shall remain in effect for a period of twenty (20) years from the Commercial Operations Date and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice. This LGIA may be terminated by the Interconnection Customer, subject to continuing obligations of this LGIA and the Tariff, after giving the Interconnecting Transmission Owner ninety (90) Calendar Days advance written notice, or by Interconnecting Transmission Owner notifying the Commission after a Generating Facility retires pursuant to the Tariff, provided that if an Interconnection Customer exercises its right to terminate on ninety (90) Calendar Days, any reconnection would be treated as a new interconnection request; or this LGIA may be terminated by Interconnecting Transmission Owner by notifying the Commission after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default. Each Party may terminate this LGIA in accordance with Article 17.

Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing, if applicable, with the Commission of a notice of termination of this LGIA, which notice has been accepted for filing by the Commission. Termination of the LGIA shall not supersede or alter any requirements for deactivation or retirement of a generating unit under ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

2.4 Termination Costs. If a Party elects to terminate this LGIA pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party(ies), as of the date of such Party's(ies') receipt of such notice of termination, that are the responsibility of such Party(ies) under this

LGIA. In the event of termination by a Party, all Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this LGIA, unless otherwise ordered or approved by the Commission:

2.4.1 With respect to any portion of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades to the extent covered by this LGIA, that have not yet been constructed or installed, the Interconnecting Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and the Interconnecting Transmission Owner shall deliver such material and equipment, and, if necessary, and to the extent possible, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Interconnecting Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, either (i) in the case of overpayment, Interconnecting Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by the Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts, or (ii) in the case of underpayment, Interconnection Customer shall promptly pay such amounts still due plus any costs, including penalties incurred by Interconnecting Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which the Interconnecting

Transmission Owner has incurred expenses and has not been reimbursed by the Interconnection Customer.

2.4.2 Interconnecting Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Interconnecting Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

2.5 Disconnection. Upon termination of this LGIA, Interconnection Service shall terminate and, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Interconnecting Transmission Owner's Interconnection Facilities. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from a non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival. This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party(ies) pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

ARTICLE 3. REGULATORY FILINGS

3.1 Filing. The Interconnecting Transmission Owner shall jointly file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required, in accordance with Section 11.3 of the LGIP. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If the Interconnection Customer has executed this LGIA, or any amendment thereto, the Interconnection Customer shall reasonably cooperate with the Interconnecting Transmission Owner with respect to such filing and to provide any information reasonably requested by the Interconnecting Transmission Owner needed to comply with applicable regulatory requirements.

ARTICLE 4. SCOPE OF SERVICE

4.1 Reserved.

4.2 Provision of Service. Interconnecting Transmission Owner shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards. Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such requirements and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith. If such Party is the Interconnecting Transmission Owner, then that Party shall amend the LGIA and Interconnecting Transmission Owner, shall submit the amendment to the Commission for approval.

4.4 No Transmission Delivery Service. The execution of this LGIA does not constitute a request for, nor the provision of, any service except for Interconnection Service, including, but not limited to, transmission delivery service, local delivery service, distribution service, capacity service, energy service, or Ancillary Services under any applicable tariff, and does not convey any right to deliver electricity to any

specific customer or Point of Delivery.

4.5 Reserved.

4.6 Interconnection Customer Provided Services. The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.4. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall specify the In-Service Date, Initial Synchronization Date, and Commercial Operation Date as specified in the Interconnection Request or as subsequently revised pursuant to Section 4.4 of the LGIP; and select either Standard Option or Alternate Option set forth below for completion of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades as set forth in Appendix A, and such dates and selected option shall be set forth in Appendix B (Milestones). In accordance with Section 8 of the LGIP and unless otherwise mutually agreed, the Alternate Option is not an available option if the Interconnection Customer waived the Interconnection Facilities Study.

5.1.1 Standard Option. The Interconnecting Transmission Owner shall design, procure, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B (Milestones). The Interconnecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Interconnecting Transmission Owner reasonably expects that it will not be able to complete the Interconnecting

Transmission Owner's Interconnection Facilities and Network Upgrades by the specified dates, the Interconnecting Transmission Owner shall promptly provide written notice to the Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option. If the dates designated by Interconnection Customer are acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days, and shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities by the designated dates.

If Interconnecting Transmission Owner subsequently fails to complete Interconnecting Transmission Owner's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B (Milestones); Interconnecting Transmission Owner shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable System Operator refuses to grant clearances to install equipment.

5.1.3 Option to Build. If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall so notify the Interconnection Customer within thirty (30) Calendar Days, and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. The System Operator, Interconnecting Transmission Owner, Interconnection Customer, and any Affected Party as

deemed appropriate by System Operator in accordance with applicable codes of conduct and confidentiality requirements must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A to the LGIA. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option. If the Interconnection Customer elects not to exercise its option under Article 5.1.3 (Option to Build), Interconnection Customer shall so notify Interconnecting Transmission Owner within thirty (30) Calendar Days, and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer) pursuant to which Interconnecting Transmission Owner is responsible for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Interconnecting Transmission Owner shall assume responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades pursuant to 5.1.1 (Standard Option).

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall engineer, procure equipment, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Interconnecting Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Interconnecting Transmission Owner would be subject in the engineering, procurement or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Interconnecting Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) prior to commencement of construction, Interconnection Customer shall provide to Interconnecting Transmission Owner a schedule for construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Interconnecting Transmission Owner;

(5) at any time during construction, Interconnecting Transmission Owner shall have the right to gain unrestricted access to the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Interconnecting Transmission Owner, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) the Interconnection Customer shall indemnify the Interconnecting Transmission Owner for claims arising from the Interconnection Customer's

construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 (Indemnity);

(8) the Interconnection Customer shall transfer control of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the Interconnecting Transmission Owner;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Interconnecting Transmission Owner;

(10) Interconnecting Transmission Owner shall approve and accept for operation and maintenance the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Interconnecting Transmission Owner "as built" drawings, information, and any other documents that are reasonably required by Interconnecting Transmission Owner to assure that the Interconnection Facilities and Stand Alone Network Upgrades are built to the standards and specifications required by Interconnecting Transmission Owner.

5.3 Liquidated Damages. The actual damages to the Interconnection Customer, in the event the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Interconnecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by the Interconnecting Transmission Owner to the Interconnection Customer in the event that Interconnecting Transmission Owner does not complete any portion of the Interconnecting Transmission Owner's Interconnection Facilities or Network

Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Interconnecting Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which the Interconnecting Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by the Interconnecting Transmission Owner to the Interconnection Customer as just compensation for the damages caused to the Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Interconnecting Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless the Interconnection Customer would have been able to commence use of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Interconnecting Transmission Owner's delay; (2) the Interconnecting Transmission Owner's failure to meet the specified dates is the result of the action or inaction of the Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with the Interconnecting Transmission Owner or any cause beyond Interconnecting Transmission Owner's reasonable control or reasonable ability to cure, including, but not limited to, actions by the System Operator that cause delays and/or delays in licensing, permitting or consents where the Interconnecting Transmission Owner has pursued such licenses, permits or consents

in good faith; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers. If a Power System Stabilizer is required to be installed on the Large Generating Facility for the purpose of maintaining system stability, the Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the System Operator and Interconnecting Transmission Owner, and consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator and Interconnecting Transmission Owner reserve the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the System Operator and Interconnecting Transmission Owner, or their designated representative. The requirements of this paragraph shall not apply to non-synchronous power production equipment.

5.5 Equipment Procurement. If responsibility for construction of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by the Interconnecting Transmission Owner, then the Interconnecting Transmission Owner shall commence design of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 The Interconnecting Transmission Owner has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 The Interconnecting Transmission Owner has received written authorization to proceed with design and procurement from the

Interconnection Customer by the date specified in Appendix B (Milestones); and

5.5.3 The Interconnection Customer has provided security to the Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.6 Construction Commencement. The Interconnecting Transmission Owner shall commence construction of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades;

5.6.3 The Interconnecting Transmission Owner has received written authorization to proceed with construction from the Interconnection Customer by the date specified in Appendix B (Milestones); and

5.6.4 The Interconnection Customer has provided security to Interconnecting Transmission Owner in accordance with Article 11.5 by the dates specified in Appendix B (Milestones).

5.7 Work Progress. The Interconnection Customer and the Interconnecting Transmission Owner shall keep each Party informed, by written quarterly progress reports, as to the progress of their respective design, procurement and construction efforts in order to meet the dates specified in Appendix B (Milestones). Any Party may also, at any other time, request a written progress report from the other Parties. If, at any time, the Interconnection Customer determines that the

completion of the Interconnecting Transmission Owner's Interconnection Facilities will not be required until after the specified In-Service Date, the Interconnection Customer will provide written notice to the Interconnecting Transmission Owner of such later date upon which the completion of the Interconnecting Transmission Owner's Interconnection Facilities will be required.

5.8 Information Exchange. As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the New England Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation. If any of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, the Interconnecting Transmission Owner shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and the Interconnection Customer's Interconnection Facilities may operate prior to the completion of the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this LGIA. System Operator and Interconnecting Transmission Owner shall permit Interconnection Customer to operate the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities ("ICIF"). Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.10.1 Large Generating Facility Specifications. Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Interconnecting Transmission Owner at least one hundred

eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Interconnecting Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Interconnecting Transmission Owner's Review. Interconnecting Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Interconnecting Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of the Interconnecting Transmission Owner.

5.10.3 ICIF Construction. The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnection Customer shall deliver to the Interconnecting Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with the Interconnection Customer's step-up transformers, the facilities connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up

transformers and the Large Generating Facilities. The Interconnection Customer shall provide Interconnecting Transmission Owner specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

5.11 Interconnecting Transmission Owner's Interconnection Facilities Construction. The Interconnecting Transmission Owner's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, the Interconnecting Transmission Owner shall deliver to the Interconnection Customer the following "as-built" drawings, information and documents for the Interconnecting Transmission Owner's Interconnection Facilities. The appropriate drawings and relay diagrams shall be included in Appendix A of this LGIA. The System Operator will obtain operational control of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities pursuant to the TOA.

5.12 Access Rights. Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at the incremental cost to another Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents if allowed under the applicable agency agreement, that are necessary to enable the Access Party solely to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Large Generating Facility with the Administered Transmission System; (ii) operate and maintain the Large Generating Facility, the Interconnection Facilities and the New England Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to

time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners. If any part of the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Interconnecting Transmission Owner, the Interconnecting Transmission Owner shall at Interconnection Customer's expense use Reasonable Efforts, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove the Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property. Notwithstanding the foregoing, the Interconnecting Transmission Owner shall not be obligated to exercise eminent domain authority in a manner inconsistent with Applicable Laws and Regulations or when an Interconnection Customer is authorized under Applicable Laws and Regulations to exercise eminent domain on its own behalf.

5.14 Permits. Interconnecting Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Interconnecting Transmission Owner shall provide permitting assistance to the Interconnection Customer comparable to that provided to the Interconnecting Transmission Owner's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities. Interconnection Customer may request Interconnecting Transmission Owner to construct, and Interconnecting Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Administered Transmission System, which are included in the Base Case of the Facilities Study for the Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-

Service Date. The Interconnection Customer shall reimburse the Interconnecting Transmission Owner for all costs incurred related to early construction to the extent such costs are not recovered from other Interconnection Customers included in the base case.

5.16 Suspension. Interconnection Customer reserves the right, upon written notice to Interconnecting Transmission Owner and System Operator, to suspend at any time all work by Interconnecting Transmission Owner associated with the construction and installation of Interconnecting Transmission Owner's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that the New England Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and the System Operator's and Interconnecting Transmission Owner's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Interconnecting Transmission Owner (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the New England Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Interconnecting Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Interconnecting Transmission Owner shall obtain Interconnection Customer's authorization to do so.

Interconnecting Transmission Owner shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Interconnecting Transmission Owner required under this LGIA pursuant to this Article 5.16, and has not requested Interconnecting Transmission Owner to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Interconnecting Transmission Owner and System Operator, if no effective date is specified. A suspension under this Article 5.16 does not

automatically permit an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date. A request for extension of such dates is subject to Section 4.4.5 of the LGIP. Notwithstanding the extensions permitted under Section 4.4.5 of the LGIP, the three-year period shall in no way result in an extension of the In-Service Date, the Initial Synchronization Date or the Commercial Operation Date that exceeds seven (7) years from the date of the Interconnection Request; otherwise, this LGIA shall be deemed terminated.

5.17 Taxes.

5.17.1 Payments Not Taxable. The Parties intend that all payments or property transfers made by any Party for the installation of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

5.17.2 Representations and Covenants. In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Large Generating Facility will pass to another party prior to the transmission of the electricity on the New England Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of the Interconnecting Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Large Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions,

calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Interconnecting Transmission Owner's request, Interconnection Customer shall provide Interconnecting Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Interconnecting Transmission Owner represents and covenants that the cost of the Interconnecting Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon Interconnecting Transmission Owner. Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Interconnecting Transmission Owner from the cost consequences of any current tax liability imposed against Interconnecting Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Interconnecting Transmission Owner.

The Interconnecting Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this LGIA unless (i) Interconnecting Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Interconnecting Transmission Owner to report payments or property as income subject to taxation; provided, however, that Interconnecting Transmission Owner may require Interconnection Customer to provide security, in a form reasonably acceptable to Interconnecting Transmission Owner (such as a parental

guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Interconnecting Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Interconnecting Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period, and the applicable statute of limitation, as it may be extended by the Interconnecting Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

5.17.4 Tax Gross-Up Amount. Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the parties, this means that Interconnection Customer will pay Interconnecting Transmission Owner, in addition to the amount paid for the Interconnection Facilities and Network Upgrades, an amount equal to (1) the current taxes imposed on Interconnecting Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Interconnecting Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under this LGIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit the Interconnecting Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).For this purpose, (i) Current Taxes shall be computed based on

Interconnecting Transmission Owner composite federal and state tax rates at the time the payments or property transfers are received and Interconnecting Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Interconnecting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Interconnecting Transmission Owner current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades).

5.17.5 Private Letter Ruling or Change or Clarification of Law. At Interconnection Customer's request and expense, Interconnecting Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Interconnecting Transmission Owner under this LGIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Interconnecting Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Interconnecting Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a

private letter ruling. Interconnecting Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

5.17.6 Subsequent Taxable Events. If, within ten (10) years from the date on which the relevant Interconnecting Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenant contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this LGIA terminates and Interconnecting Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, the Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Interconnecting Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

5.17.7 Contests. In the event any Governmental Authority determines that Interconnecting Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Interconnecting Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Interconnecting Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Interconnecting Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Interconnecting Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Interconnecting Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall

reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Interconnecting Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Interconnecting Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Interconnecting Transmission Owner for the tax at issue in the contest.

5.17.8 Refund. In the event that (a) a private letter ruling is issued to Interconnecting Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Interconnecting Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Interconnecting Transmission Owner under the terms of this LGIA is not taxable to Interconnecting Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a

determination that any payments or transfers made by Interconnection Customer to Interconnecting Transmission Owner are not subject to federal income tax, or (d) if Interconnecting Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Interconnecting Transmission Owner pursuant to this LGIA, Interconnecting Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amounts paid by Interconnection Customer to Interconnecting Transmission Owner for such taxes which Interconnecting Transmission Owner did not submit to the taxing authority, interest calculated in accordance with the methodology set forth in the Commission's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Interconnecting Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Interconnecting Transmission Owner, any refund or credit Interconnecting Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to the Interconnecting Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Interconnecting Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Interconnecting Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Interconnecting Transmission Owner has received a tax refund,

credit or offset from any Governmental Authority for any applicable overpayment of income tax related to the Interconnecting Transmission Owner's Interconnection Facilities.

The intent of this provision is to leave Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

5.17.9 Taxes Other Than Income Taxes. Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Interconnecting Transmission Owner shall appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Interconnecting Transmission Owner for which Interconnection Customer may be required to reimburse Interconnecting Transmission Owner under the terms of this LGIA. Interconnection Customer shall pay to Interconnecting Transmission Owner on a periodic basis, as invoiced by Interconnecting Transmission Owner, Interconnecting Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Interconnecting Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Interconnecting Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Interconnecting Transmission Owner.

5.18 Tax Status. Each Party shall cooperate with the others to maintain the other Party's(ies') tax status. Nothing in this LGIA is intended to adversely affect any Interconnecting Transmission Owner's tax-exempt status with respect to the

issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General. Either Interconnection Customer or Interconnecting Transmission Owner may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, the facilities of any Affected Parties, or the New England Transmission System, that Party shall provide to the other Parties and any Affected Party: (i) sufficient information regarding such modification so that the other Party(ies) may evaluate the potential impact of such modification prior to commencement of the work; and (ii) such information as may be required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Party(ies) at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed. Notwithstanding the foregoing, no Party shall be obligated to proceed with a modification that would constitute a Material Modification and therefore require an Interconnection Request under the LGIP, except as provided under and pursuant to the LGIP.

In the case of Large Generating Facility or Interconnection Customer's Interconnection Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Interconnecting Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the New England Transmission System, Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades

necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards. Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs. Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Interconnecting Transmission Owner makes to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System to facilitate the interconnection of a third party to the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System, or to provide transmission service to a third party under the Tariff, except as provided for under the Tariff or any other applicable tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

ARTICLE 6. TESTING AND INSPECTION

6.1 Pre-Commercial Operation Date Testing and Modifications. Prior to the Commercial Operation Date, the Interconnecting Transmission Owner shall test Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and the Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test

energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications. Each Interconnection Customer and Interconnecting Transmission Owner shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, as may be necessary to ensure the continued interconnection of the Large Generating Facility to the Administered Transmission System in a safe and reliable manner. The Interconnection Customer and Interconnecting Transmission Owner each shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's(ies') facilities, at the requesting Party's expense, as may be in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The System Operator shall also have the right to require reasonable additional testing of the other Party's (ies') facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

6.3 Right to Observe Testing. Each Party shall notify the System Operator and other Party(ies) in advance of its performance of tests of its Interconnection Facilities. The other Party(ies) has the right, at its own expense, to observe such testing.

6.4 Right to Inspect. Each Party shall have the right, but shall have no obligation to: (i) observe the other Party's(ies') tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (ii) review the settings of the other Party's(ies') System Protection Facilities and other protective equipment; and (iii) review the other Party's(ies') maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Each Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any

information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be governed by Article 22.

ARTICLE 7. METERING

7.1 General. Each Party shall comply with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding metering. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment. Unless the System Operator otherwise agrees, the Interconnection Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this Tariff and to communicate the information to the System Operator. Unless otherwise agreed, such equipment shall remain the property of the Interconnecting Transmission Owner.

7.2 Check Meters. Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Interconnecting Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Interconnecting Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards. Interconnecting Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards and the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.4 Testing of Metering Equipment. Interconnecting Transmission Owner shall inspect and test all Interconnecting Transmission Owner-owned Metering Equipment upon installation and thereafter as specified in the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall give reasonable notice of the time when

any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than the values specified within ISO New England Operating Documents, or successor documents, from the measurement made by the standard meter used in the test, the Interconnecting Transmission Owner shall adjust the measurements, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

7.5 Metering Data. At Interconnection Customer's expense, metered data shall be telemetered to one or more locations designated by System Operator and Interconnecting Transmission Owner. The hourly integrated metering, established in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, used to transmit Megawatt hour ("MWh") per hour data by electronic means and the Watt-hour meters equipped with kilowatt-hour ("kwh") or MWh registers to be read at month's end shall be the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection. Instantaneous metering is required for all Generators in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 8. COMMUNICATIONS

8.1 Interconnection Customer Obligations. Interconnection Customer shall maintain satisfactory operating communications with the System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

8.2 Remote Terminal Unit. Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection

Customer or Interconnecting Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by System Operator and Interconnecting Transmission Owner through use of a dedicated point-to-point data circuit(s). The communication protocol for the data circuit(s) shall be specified by System Operator and Interconnecting Transmission Owner. All information required by the ISO New England Operating Documents, or successor documents, must be telemetered directly to the location(s) specified by System Operator and Interconnecting Transmission Owner.

Each Party will promptly advise the other Party(ies) if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party(ies). The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation. Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

8.4 Provision of Data from an Intermittent Power Resource. The Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall provide meteorological and forced outage data to the System Operator to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The Interconnection Customer with an Intermittent Power Resource having wind as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with an Intermittent Power Resource having solar as the energy source, at a minimum, will be required to provide the System Operator with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The System Operator and Interconnection Customer whose Generating Facility is an Intermittent Power Resource shall mutually agree to any additional meteorological

data that are required for the development and deployment of a power product forecast. The Interconnection Customer whose Generating Facility is an Intermittent Power Resource also shall submit data to the System Operator regarding all forced outages to the extent necessary for the System Operator's development and deployment of power production forecasts for that class of Intermittent Power Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the System Operator, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Intermittent Power Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the System Operator. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with applicable provisions of ISO New England Operating Documents, Reliability Standards, or successor documents, regarding operations. Each Party shall provide to the other Party(ies) all information that may reasonably be required by the other Party(ies) to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification. Before Initial Synchronization Date, the Interconnection Customer shall notify the System Operator and Interconnecting Transmission Owner in writing in accordance with ISO New England Operating Documents, Reliability Standards, or successor documents. If the Interconnection Customer elects to have the Large Generating Facility dispatched and operated from a remote Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs and ISO New England Operating Documents, Reliability Standards, or successor documents, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator

interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area for dispatch and operations.

9.3 Interconnecting Transmission Owner and System Operator Obligations. Interconnecting Transmission Owner and System Operator shall cause the Interconnecting Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Reliability Standards, or successor documents. Interconnecting Transmission Owner or System Operator may provide operating instructions to Interconnection Customer consistent with this LGIA, ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and Interconnecting Transmission Owner's and System Operator's operating protocols and procedures as they may change from time to time. Interconnecting Transmission Owner and System Operator will consider changes to their operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations. Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA and ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.5 Start-Up and Synchronization. The Interconnection Customer is responsible for the proper start-up and synchronization of the Large Generating Facility to the New England Transmission System in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria. Interconnection Customer shall design the Large Generating Facility and all generating units comprising the Large Generating Facility, as applicable, to maintain a composite power delivery at

continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the System Operator or Interconnecting Transmission Owner has established different requirements that apply to all generators in the Control Area on a comparable basis and in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The requirements of this paragraph shall not apply to wind generators.

9.6.2 Voltage Schedules. Once the Interconnection Customer has synchronized the Large Generating Facility to the New England Transmission System, Interconnection Customer shall operate the Large Generating Facility at the direction of System Operator and Interconnecting Transmission Owner in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, regarding voltage schedules in accordance with such requirements.

9.6.2.1 Voltage Regulators. The Interconnection Customer must keep and maintain a voltage regulator on all generating units comprising a Large Generating Facility in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. All Interconnection Customers that have, or are required to have, automatic voltage regulation shall normally operate the Large Generating Facility with its voltage regulators in automatic operation.

It is the responsibility of the Interconnection Customer to maintain the voltage regulator in good operating condition and promptly report to the System Operator and Interconnecting Transmission Owner any problems that could cause interference with its proper operation.

9.6.2.2 Governor Control. The Interconnection Customer is obligated to provide and maintain a functioning governor on all generating units comprising the Large Generating Facility in accordance with applicable provisions of the ISO New England Operating

Documents, Applicable Reliability Standards, or successor documents.

9.6.2.3 System Protection. The Interconnection Customer shall install and maintain protection systems in accordance with applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.6.3 Payment for Reactive Power.

Interconnection Customers shall be compensated for Reactive Power service in accordance with Schedule 2 of the Section II of the Tariff.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination. The System Operator shall have the authority to coordinate facility outages in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Each Party may in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, in coordination with the other Party(ies), remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's(ies') facilities as necessary to perform maintenance or testing or to install or replace equipment, subject to the oversight of System Operator in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.1.2 Outage Schedules. Outage scheduling, and any related compensation, shall be in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.2 Interruption of Service. **In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, the System Operator or Interconnecting Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect System Operator's or Interconnecting Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the New England Transmission System.**

9.7.3 Under-Frequency and Over Frequency Conditions. **Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the applicable provisions of ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with System Operator and Interconnecting Transmission Owner in accordance with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.**

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities. **Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. Interconnecting Transmission Owner shall install at Interconnection Customer's expense, in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, any System Protection Facilities that may be required on the Interconnecting Transmission Owner Interconnection Facilities or**

the New England Transmission System as a result of the interconnection of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.4.4 Each Party's protective relay design shall allow for tests required in Article 6.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

9.7.5 Requirements for Protection. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, and compliance with Good Utility Practice , Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the New England Transmission System not otherwise isolated by Interconnecting Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the New England Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the New England Transmission System at a site selected upon mutual

agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the New England Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality. A Party's facilities shall not cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard.

9.8 Switching and Tagging Rules. Each Party shall provide the other Party(ies) with a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities. Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Administered Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users. If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use the Interconnecting Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection

Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Interconnecting Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed-upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to the Commission for resolution.

9.10 Disturbance Analysis Data Exchange. The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or the New England Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 10. MAINTENANCE

10.1 Interconnecting Transmission Owner and Customer Obligations. Interconnecting Transmission Owner and Interconnection Customer shall each maintain that portion of its respective facilities that are part of the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with the applicable provisions of the

ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

10.2 Operating and Maintenance Expenses. Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Interconnecting Transmission Owner's Interconnection Facilities, Stand Alone Network Upgrades, Network Upgrades and Distribution Upgrades.

ARTICLE 11. PERFORMANCE OBLIGATION

11.1 Interconnection Customer's Interconnection Facilities. Interconnection Customer shall design, procure, construct, install, own and/or control the Interconnection Customer's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at its sole expense.

11.2 Interconnecting Transmission Owner's Interconnection Facilities. Interconnecting Transmission Owner shall design, procure, construct, install, own and/or control the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades) at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades. Interconnecting Transmission Owner shall design, procure, construct, install, and own the Network Upgrades, and to the extent provided by Article 5.1, Stand Alone Network Upgrades, and Distribution Upgrades described in Appendix A (Interconnection Facilities, Network Upgrades and Distribution Upgrades). The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless the Interconnecting Transmission Owner elects to fund the capital for the Network

Upgrades, they shall be solely funded by the Interconnection Customer.

11.4 Cost Allocation; Compensation; Rights; Affected Systems

11.4.1 Cost Allocation. Cost allocation of Generator Interconnection Related Upgrades shall be in accordance with Schedule 11 of Section II of the Tariff.

11.4.2 Compensation. Any compensation due to the Interconnection Customer for increases in transfer capability to the PTF resulting from its Generator Interconnection Related Upgrade shall be determined in accordance with Sections II and III of the Tariff.

11.4.3 Rights. Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that the Interconnection Customer shall be entitled to, now or in the future, under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades.

11.4.4 Special Provisions for Affected Systems. The Interconnection Customer shall enter into separate related facilities agreements to address any upgrades to the Affected System(s) that are necessary for safe and reliable interconnection of the Interconnection Customer's Generating Facility.

11.5 Provision of Security. At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of an Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, Interconnection Customer shall provide Interconnecting Transmission Owner a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Interconnecting Transmission Owner in accordance with Section 7 of Schedule 11 of the Tariff. In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Interconnecting Transmission Owner, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Interconnecting Transmission Owner and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation. If System Operator or Interconnecting Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.4.1 of this LGIA, Interconnection Customer shall be compensated pursuant to the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

11.6.1 Interconnection Customer Compensation for Actions During Emergency Condition. Interconnection Customer shall be compensated for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the New England Transmission System during an Emergency Condition in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 12. INVOICE

12.1 General. Each Party shall submit to the other Party(ies), on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due

and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party(ies) under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice. Within six months after completion of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades, Interconnecting Transmission Owner shall provide an invoice of the final cost of the construction of the Interconnecting Transmission Owner's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnecting Transmission Owner shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice. Interconnection Customer shall pay to Interconnecting Transmission Owner any amount by which the actual payment by Interconnection Customer for estimated costs falls short of the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment. Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by any Party will not constitute a waiver of any rights or claims the other Party(ies) may have under this LGIA.

12.4 Disputes. In the event of a billing dispute between Interconnecting Transmission Owner and Interconnection Customer, Interconnecting Transmission Owner shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Interconnecting Transmission Owner or into an independent escrow

account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Interconnecting Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in the Commission's Regulations at 18 CFR § 35.19a(a)(2)(iii).

ARTICLE 13. EMERGENCIES

13.1 Obligations. Each Party shall comply with the Emergency Condition procedures of the System Operator in accordance with the applicable provisions of the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

13.2 Notice. Interconnecting Transmission Owner or System Operator as applicable shall notify Interconnection Customer and System Operator or Interconnecting Transmission Owner as applicable, promptly when it becomes aware of an Emergency Condition that affects the Interconnecting Transmission Owner's Interconnection Facilities or the New England Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Interconnecting Transmission Owner and System Operator promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or the Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Interconnecting Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as

soon as practicable with written notice.

13.3 Immediate Action. Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Interconnecting Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or the Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by the Interconnecting Transmission Owner or otherwise regarding the New England Transmission System.

13.4 System Operator's and Interconnecting Transmission Owner's Authority.

13.4.1 General. System Operator or Interconnecting Transmission Owner may take whatever actions or inactions with regard to the New England Transmission System or the Interconnecting Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the New England Transmission System or Interconnecting Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or the Interconnection Customer's Interconnection Facilities. System Operator and Interconnecting Transmission Owner may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility; implementing a reduction or disconnection pursuant to Article 13.4.2; directing the Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage

schedules of the Large Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of System Operator's and Interconnecting Transmission Owner's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.4.2 Reduction and Disconnection. System Operator and Interconnecting Transmission Owner may reduce Interconnection Service or disconnect the Large Generating Facility or the Interconnection Customer's Interconnection Facilities when such reduction or disconnection is necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. These rights are separate and distinct from any right of curtailment of the System Operator and Interconnecting Transmission Owner pursuant to the Tariff. When the System Operator and Interconnecting Transmission Owner can schedule the reduction or disconnection in advance, System Operator and Interconnecting Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. System Operator and Interconnecting Transmission Owner shall coordinate with the Interconnection Customer in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents to schedule the reduction or disconnection during periods of least impact to the Interconnection Customer and the System Operator and Interconnecting Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities, and the New England Transmission System to their normal operating state as soon as practicable in accordance with the ISO New England Operating Documents, Applicable Reliability Standards,

or successor documents.

13.5 Interconnection Customer Authority. In accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents and the LGIA and the LGIP, the Interconnection Customer may take whatever actions or inactions with regard to the Large Generating Facility or the Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Large Generating Facility or the Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the New England Transmission System and the Interconnecting Transmission Owner's Interconnection Facilities. System Operator and Interconnecting Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.6 Limited Liability. Except as otherwise provided in Article 11.6.1 of this LGIA, a Party shall not be liable to another Party for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and in accordance with the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents.

ARTICLE 14. REGULATORY REQUIREMENTS AND GOVERNING LAW

14.1 Regulatory Requirements. Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act or the Public Utility Holding Company Act of 1935, as amended. To the extent that a condition arises that could

result in Interconnection Customer's inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978, the Parties shall engage in good faith negotiations to address the condition so that such result will not occur and so that this LGIA can be performed.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

ARTICLE 15. NOTICES

15.1 General. Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by a Party to another Party and any instrument required or permitted to be tendered or delivered by a Party in writing to another Party shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F (Addresses for Delivery of Notices and Billings).
A Party may change the notice information in this LGIA by giving five (5) Business Days written notice prior to the effective date of the change.

15.2 Billings and Payments. Billings and payments shall be sent to the addresses set out in Appendix F.

15.3 Alternative Forms of Notice. Any notice or request required or permitted to be given by a Party to another Party and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

15.4 Operations and Maintenance Notice. Each Party shall notify the other Party(ies) in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

ARTICLE 16. FORCE MAJEURE

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 A Party shall not be considered to be in Default with respect to any obligation hereunder (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party(ies) in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this Article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

ARTICLE 17. DEFAULT

17.1 Default.

17.1.1 General. No Breach shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act or omission of the other Party(ies). Upon a Breach, the non-Breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the Breaching Party shall have thirty (30) Calendar Days from receipt of the Breach notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the Breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Breach notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate. If a Breach is not cured as provided in this Article, or if a Breach is not capable of being cured within the period provided for herein, the non-Breaching Party(ies) shall have the right to terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not those Parties terminate this LGIA, to recover from the Breaching Party all amounts due hereunder, plus all other damages and remedies to which they are entitled at law or in equity. The provisions of this Article will survive termination of this LGIA.

ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES AND INSURANCE

Notwithstanding any other provision of this Agreement, the liability, indemnification and insurance provisions of the Transmission Operating Agreement ("TOA") or other applicable operating agreements shall apply to the relationship between the System Operator and the Interconnecting Transmission

Owner and the liability, indemnification and insurance provisions of the Tariff apply to the relationship between the Interconnecting Transmission Owner and the Interconnection Customer.

18.1 Indemnity. Each Party shall at all times indemnify, defend, and save the other Party(ies) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's(ies') action or inactions of their obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by an indemnified Party.

18.1.1 Indemnified Person. If an Indemnified Person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the Indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such Indemnified Person may at the expense of the Indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

18.1.2 Indemnifying Party. If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures. Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such Indemnifying Party and reasonably satisfactory to the Indemnified Person. If the defendants in any such action include one or more Indemnified Persons and the Indemnifying Party and if the Indemnified Person reasonably concludes that there may be legal defenses available to it and/or other Indemnified Persons which are different from or additional to those available to the Indemnifying Party, the Indemnified Person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the Indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an Indemnified Person or Indemnified Persons having such differing or additional legal defenses.

The Indemnified Person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the Indemnifying Party. Notwithstanding the foregoing, the Indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the Indemnified Person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the Indemnified Person, or there exists a conflict or adversity of interest between the Indemnified Person and the Indemnifying Party, in which event the Indemnifying Party shall pay the reasonable expenses of the Indemnified Person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the Indemnified Person, which shall not be reasonably withheld, conditioned or delayed.

18.2 Consequential Damages. Other than the Liquidated Damages heretofore described, in no event shall a Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether

based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

18.3 Insurance. The Interconnecting Transmission Owner and the Interconnection Customer shall, at their own expense, maintain in force throughout the period of this LGIA, and until released by the other Party(ies), the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death, and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability

Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party(ies), its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by the Parties are not intended to and shall not in any

manner, limit or qualify the liabilities and obligations assumed by the Parties under this LGIA.

18.3.9 Within ten (10) days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, each Party shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program, provided that such Party's senior secured debt is rated at investment grade, or better, by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this Article, it shall notify the other Party(ies) that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

ARTICLE 19. ASSIGNMENT

19.1 Assignment. This LGIA may be assigned by any Party only with the written consent of the other Parties; provided that the Parties may assign this LGIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to

satisfy the obligations of the assigning Party under this LGIA; and provided further that the Interconnection Customer shall have the right to assign this LGIA, without the consent of the Interconnecting Transmission Owner or System Operator, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that the Interconnection Customer will promptly notify the Interconnecting Transmission Owner and System Operator of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Interconnecting Transmission Owner and System Operator of the date and particulars of any such exercise of assignment right(s), including providing the Interconnecting Transmission Owner with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this Article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

ARTICLE 20. SEVERABILITY

20.1 Severability. If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if the Interconnection Customer (or any third party, but only if such third party is not acting at the direction of the Interconnecting Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

ARTICLE 21. COMPARABILITY

21.1 Comparability. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

ARTICLE 22. CONFIDENTIALITY

22.1 Confidentiality. Confidential Information shall include, without limitation, all information governed by the ISO New England Information Policy, all information obtained from third parties under confidentiality agreements, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by a Party to another prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by a Party, the other Party(ies) shall provide, in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term. During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party

without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party(ies) that it no longer is confidential.

22.1.3 Release of Confidential Information. A Party shall not release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 Rights. Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party(ies). The disclosure by each Party to the other Party(ies) of Confidential Information shall not be deemed a waiver by a Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 No Warranties. By providing Confidential Information, a Party does not

make any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, a Party does not obligate itself to provide any particular information or Confidential Information to the other Party(ies) nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party(ies) under this LGIA or its regulatory requirements.

22.1.7 Order of Disclosure. If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party(ies) with prompt notice of such request(s) or requirement(s) so that the other Party(ies) may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement. Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party(ies), use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party(ies)) or return to the other Party(ies), without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party(ies).

22.1.9 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's(ies') Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party(ies) shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Parties shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to the Commission, its Staff, or a State. Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR. section 1b.20, if the Commission or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to the Commission or its staff, within the time provided for in the request for information. In providing the information to the Commission or its staff, the Party must, consistent with 18 CFR section 388.112, request that the information be treated as confidential and non-public by the Commission and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party(ies) to this LGIA prior to the release of the Confidential Information to the Commission or its staff. The Party shall notify the other Party(ies) to the LGIA when it is notified by the Commission or its staff that a request to release Confidential Information has been received by the Commission, at which time any of the Parties may respond before such information would be made public, pursuant to 18 CFR section 388.112. Requests from a state

regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party(ies) to any person not employed or retained by the other Party(ies), except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party(ies), such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party(ies) in writing of the information it claims is confidential. Prior to any disclosures of the other Parties' Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party(ies) in writing and agrees to assert confidentiality and cooperate with the other Party(ies) in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

ARTICLE 23. ENVIRONMENTAL RELEASES

23.1 Each Party shall notify the other Party(ies), first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Large Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party(ies). The notifying Party shall: (i) provide the notice as soon as

practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four (24) hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party(ies) copies of any publicly available reports filed with any Governmental Authorities addressing such events.

ARTICLE 24. INFORMATION REQUIREMENTS

24.1 Information Acquisition. Subject to any applicable confidentiality restrictions, including, but not limited to, codes of conduct, each Party shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Interconnecting Transmission Owner. The initial information submission by Interconnecting Transmission Owner shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date and shall include information necessary to allow the Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise mutually agreed to by the Parties. On a monthly basis Interconnecting Transmission Owner shall provide Interconnection Customer a status report on the construction and installation of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer. The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Interconnecting Transmission Owner and System Operator for the

Interconnection Feasibility Study, Interconnection System Impact Study and Interconnection Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Interconnecting Transmission Owner standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is different from what was originally provided to Interconnecting Transmission Owner pursuant to the Interconnection Study Agreement between Interconnecting Transmission Owner and Interconnection Customer, then the Interconnecting Transmission Owner will review it and conduct appropriate studies, as needed, at the Interconnection Customer's cost, to determine the impact on the New England Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation. Prior to the Commercial Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information and "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that

direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to the Interconnecting Transmission Owner for each individual generating unit in a station.

The Interconnection Customer shall provide the Interconnecting Transmission Owner with any information changes due to proposed equipment replacement, repair, or adjustment. Interconnecting Transmission Owner shall provide the Interconnection Customer with any information changes due to proposed equipment replacement, repair or adjustment in the directly connected substation or any adjacent Interconnecting Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information in accordance with Article 5.19 of this Agreement.

ARTICLE 25. INFORMATION ACCESS AND AUDIT RIGHTS

25.1 Information Access. Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Party(ies) to: (i) verify the costs incurred by the disclosing Party for which the other Party(ies) are responsible under this LGIA; and (ii) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events. Each Party (the "notifying Party") shall notify the other Party(ies) when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with

respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Article shall not entitle the Party receiving such notification to allege a cause for anticipatory Breach of this LGIA.

25.3 Audit Rights. Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party(ies), to audit at its own expense the other Party's(ies') accounts and records pertaining to a Party's performance or a Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's(ies') costs, calculation of invoiced amounts, the efforts to allocate responsibility for the provision of reactive support to the New England Transmission System, the efforts to allocate responsibility for interruption or reduction of generation on the New England Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this Article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records. Accounts and records related to the design, engineering, procurement, and construction of Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four (24) months following Interconnecting Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records. Accounts and records related to a Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the

auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four (24) months after the event for which the audit is sought.

25.5 Audit Results. If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party(ies) together with those records from the audit which support such determination.

ARTICLE 26. SUBCONTRACTORS

26.1 General. Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party(ies) for the performance of such subcontractor.

26.2 Responsibility of Principal. The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party(ies) for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Interconnecting Transmission Owner be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance. The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

ARTICLE 27. DISPUTES

27.1 Submission. In the event a Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party(ies) with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party(ies). In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's(ies') receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures. Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The arbitrators chosen by the Parties shall select a third member who shall chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable Commission regulations or RTO rules; provided, however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail

27.3 Arbitration Decisions. Unless otherwise agreed by the Parties, the arbitrator(s)

shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities, or Network Upgrades.

27.4 Costs. Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three member panel; or (2) a pro rata share of the cost of a single arbitrator chosen by the Parties.

ARTICLE 28. REPRESENTATIONS, WARRANTIES AND COVENANTS

28.1 General. Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority. Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict. The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval. Such Party has sought or obtained, or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

ARTICLE 29. [OMITTED]

ARTICLE 30. MISCELLANEOUS

30.1 Binding Effect. This LGIA and the rights and obligations hereof shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts. In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation. **This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix of this LGIA, or such Section of the LGIP or such Appendix of the LGIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".**

30.4 Entire Agreement. **Except for the ISO New England Operating Documents, Applicable Reliability Standards, or successor documents, this LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. Except for the ISO New England Operating Documents, Applicable Reliability Standards, any applicable tariffs, related facilities agreements, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, any Party's compliance with its obligations under this LGIA.**

30.5 No Third Party Beneficiaries. This LGIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver. The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, or duty of this LGIA. Termination or Default of this LGIA for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Interconnecting Transmission Owner. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings. The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

30.8 Multiple Counterparts. This LGIA may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment. The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by all of the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of

all Applicable Laws and Regulations.

30.11 Reservation of Rights. Consistent with Section 11.3 of the LGIP, Interconnecting Transmission Owner shall have the right to make unilateral filings with the Commission to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with the Commission to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and the Commission's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Parties and to participate fully in any proceeding before the Commission in which such modifications may be considered. In the event of disagreement on terms and conditions of the LGIA related to the costs of upgrades to such Interconnecting Transmission Owner's transmission facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of Interconnecting Transmission Owner, and any provisions related to physical impacts of the interconnection on Interconnecting Transmission Owner's transmission facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to Interconnecting Transmission Owner's position on such terms and conditions. Nothing in this LGIA shall limit the rights of the Parties or of the Commission under sections 205 or 206 of the Federal Power Act and the Commission's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

30.12 No Partnership. This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

IN WITNESS WHEREOF, the Parties have executed this LGIA in triplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

New England Power Company (Interconnecting Transmission Owner)

By: William L. Malee

William L. Malee

Title: Director, Transmission Commercial & Authorized Representative

Date: 16 July 2014

Deepwater Block Island Wind, LLC (Interconnection Customer)

By: Jeffrey Grybowski

Title: CEO

Date: 7/16/14

APPENDICES TO LGIA

APPENDIX A TO LGIA

Interconnection Facilities, Network Upgrades and Distribution Upgrades

The Interconnection Facilities, Network Upgrades and Distribution Upgrades discussed below will be engineered, designed, constructed, owned, and maintained by a combination of the Interconnecting Transmission Owner, Interconnecting Transmission Owner's Affiliate: The Narragansett Electric Company ("TNECO"), and the Interconnection Customer, as specified below. Any reference to "Affiliate" below is specifically a reference to TNECO. It is acknowledged that the Interconnecting Transmission Owner will be responsible for coordinating with Interconnecting Transmission Owner's Affiliate as necessary to meet its obligations under this Agreement. It is further acknowledged by the Parties that Interconnecting Transmission Owner's Affiliate will own and maintain certain facilities identified under this Agreement, (hereafter, the "Interconnecting Transmission Owner's Affiliate Interconnection Facilities").

1. Interconnection Facilities:

a. Point of Interconnection and Point of Change of Ownership.

The Point of Interconnection shall be the "Delivery Point" as defined in the Power Purchase Agreement executed between Interconnecting Transmission Owner's Affiliate and Interconnection Customer on June 30, 2010, as the same may be amended and/or restated from time to time (the "Power Purchase Agreement"), which shall be the point at which the Interconnection Facilities connect to the low voltage side of Interconnecting Transmission Owner's Affiliate's substation, which is to be constructed on Block Island ("Block Island Substation").

The Point of Change of Ownership shall be the point at which the terrestrial cable, which shall be owned by Interconnecting Transmission Owner's Affiliate, shall terminate in Interconnection Customer's transition vault, located at Block Island Town Beach on Block Island, and shall be spliced with Interconnection Customer's submarine cable.

The metering point shall be located at the Point of Interconnection.

The Point of Interconnection, the Point of Change of Ownership and the metering point are shown in Appendix A-1, which drawing is attached hereto and made part hereof. This is a preliminary drawing for the purposes of illustrating the general arrangement of the interconnection. Additional details will be established in the Protection Philosophy to be established by the Parties.

b. Interconnection Customer's Interconnection Facilities (including metering equipment).

The Interconnection Customer shall design to Interconnecting Transmission Owner's specifications, construct, own, operate, and maintain a 34.5kV undersea cable system from the wind farm in Block Island Sound to Block Island Town Beach, including the splices to the Interconnecting Transmission Owner's Affiliate's portions of the underground power cable, fiber optic cables, and neutral/ground continuity conductor in the transition vault at the beach, and certain data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment, as needed, located within a separate building in the Block Island substation (the "Interconnection Customer's Control Building"), as shown in the one-line diagram attached as Appendix A-1 and the general arrangement diagram attached as Appendix A-2.

Upon notification to Interconnecting Transmission Owner's Affiliate's control room, Interconnecting Transmission Owner's Affiliate shall allow Interconnection Customer (or an independent Person mutually acceptable to the Parties) access to the Block Island Substation for the purpose of facilitating Interconnection Customer's execution of its rights and obligations as set forth in Section 4.7 of the Power Purchase Agreement, including but not limited to the inspection, testing, calibration and audit of Interconnection Customer's revenue meter. Interconnection Customer shall have the right to

install an additional check meter.

The Parties agree that Interconnection Customer's cost responsibility for the Direct Assignment Facilities, described in Section 4(A) of Appendix C to this LGIA, shall satisfy all of the Interconnection Customer's obligations to engineer, procure, provide, construct install, own, keep, operate or maintain any equipment, systems, rights of use, licenses, rights of way and easements in connection with this agreement, including but not limited to those obligations set forth in Sections 5.13, 5.19, 6.1, 8.2, 9.4, 9.7.4, 9.7.5, 10.2 and Appendix C.3.B of the LGIA. Direct Assignment Facilities shall have the meaning set forth in the Tariff.

c. Interconnecting Transmission Owner's Interconnection Facilities (including metering equipment).

The Interconnecting Transmission Owner's Affiliate shall design, construct, own, operate and maintain the following equipment, at Interconnection Customer's expense, which collectively constitute the Interconnecting Transmission Owner's Affiliate Interconnection Facilities, i.e. the Direct Assignment Facilities: (1) a 34.5kV breaker and associated substation equipment as shown in Appendix A-1 and in Appendix A-2, (2) a 34.5kV grounding transformer, (3) an 34.5kV overhead circuit across the property upon which the substation is to be located, and (4) an underground cable system along a public way from the substation property to the Interconnection Customer's transition vault to be located at the Block Island Town Beach.

The Direct Assignment Facilities constitute all of Interconnecting Transmission Owner's Affiliate Interconnection Facilities.

The Interconnecting Transmission Owner will not design, construct, own, operate and maintain any equipment.

2. Network Upgrades:

a. Stand Alone Network Upgrades. None.

b. Other Network Upgrades. None.

3. Distribution Upgrades. None

4. Affected System Upgrades. None.

5. Contingency Upgrades List:

a. Long Lead Facility-Related Upgrades. Not Applicable.

The Interconnection Customer's Large Generating Facility is associated with a Long Lead Facility, in accordance with Section 3.2.3 of the LGIP. Pursuant to Section 4.1 of the LGIP, the Interconnection Customer shall be responsible for the following upgrades in the event that the Long Lead Facility achieves Commercial Operation and obtains a Capacity Supply Obligation in accordance with Section III.13.1 of the Tariff:

None

If the Interconnection Customer fails to cause these upgrades to be in-service prior to the commencement of the Long Lead Facility's Capacity Commitment Period, the Interconnection Customer shall be deemed to be in Breach of this LGIA in accordance with Article 17.1, and the System Operator will initiate all necessary steps to terminate this LGIA, in accordance with Article 2.3.

b. Other Contingency Upgrades. None.

6. Post-Forward Capacity Auction Re-study Upgrade Obligations. To be determined

APPENDIX A-1 TO LGIA: ONE-LINE DIAGRAM

[this page to be substituted for the one-line diagram found in Attachment A Clean Tariff submitted with this filing]

APPENDIX A-2 TO LGIA: GENERAL ARRANGEMENT DIAGRAM

[this page to be substituted for the diagram found in Attachment A Clean Tariff submitted with this filing]

APPENDIX B TO LGIA

Milestones

1. **Selected Option Pursuant to Article 5.1: Interconnection Customer selects the 5.1.1 Standard Option. Options described in Articles 5.1.2, 5.1.3 and 5.1.4 shall not apply to this LGIA.**

2. **Milestones and Other Requirements for all Large Generating Facilities: The description and entries listed in the following table establish the required Milestones in accordance with the provisions of the LGIP and this LGIA. The referenced section of the LGIP or article of the LGIA should be reviewed by each Party to understand the requirements of each milestone.**

Item No.	Milestone Description	Responsible Party	Date	LGIP/LGIA Reference
1	Provide evidence of continued Site Control to System Operator, or $250,000 non-refundable deposit to Interconnecting Transmission Owner	Interconnection Customer	Completed	§ 11.3.1.1 of LGIP
2	Provide evidence of one or more milestones specified in § 11.3 of LGIP	Interconnection Customer	Complete, Purchase Power Agreement executed on June 30, 2010	§ 11.3.1.2 of LGIP
3	Commit to a schedule for payment of upgrades	Interconnection Customer	Completed upon execution of the LGIA. See	§ 11.3.1.2 of LGIP

			Milestone 8.	
4	**Provide either (1) evidence of Major Permits or (2) refundable deposit to Interconnecting Transmission Owner**	**Interconnection Customer**	**Completed**	**§ 11.3.1.2 of LGIP**
5	**Provide certificate of insurance**	**Interconnection Customer and Interconnecting Transmission Owner**	**Within ten (10) days following execution of this LGIA**	**§ 18.3.9 of LGIA**
6	**Provide siting approval for Generating Facility and Interconnection Facilities to Interconnecting Transmission Owner**	**Interconnection Customer**	**By September 1, 2014**	**§ 7.5 of LGIP**
7A	**Receive Governmental Authority approval for any facilities requiring regulatory approval**	**Interconnection Customer**	**By September 1, 2014**	**§ 5.6.1 of LGIA**
7B	**Obtain necessary real property rights and rights-of-way for the construction of the Interconnecting Transmission Owner's Affiliate Interconnection Facilities**	**Interconnecting Transmission Owner**	**By September 1, 2014**	**§ 5.6.2 of LGIA**

7C **7C.1** **7C.2** **7C.3** **7.C.4**	**Provide to Interconnecting Transmission Owner written authorization to proceed with:** **pre-design** **design,** **equipment procurement** **and construction**	**Interconnection Customer**	**Upon execution of this Agreement*** **By September 1, 2014*.** **By December 1, 2014*.** **By March 1, 2015*.**	**§ 5.5.2 and § 5.6.3 of LGIA**
7D	**Provide quarterly written progress reports**	**Interconnection Customer and Interconnecting Transmission Owner**	**15 Calendar Days after the end of each quarter beginning the quarter that includes the date for Milestone 7C and ending upon completion of the Large Generating Facility and Interconnection Facilities**	**§ 5.7 of LGIA**
8	**Provision of Security to Interconnecting Transmission Owner pursuant to Section 11.5 of LGIA**	**Interconnection Customer**	**pre design pre-payment due by September 1, 2014. Remaining Pre-payments due with**	**§§ 5.5.3 and 5.6.4 of LGIA**

			written authorizations from Milestone 7C	
9	**Provision of Security Associated with Tax Liability to Interconnecting Transmission Owner pursuant to Section 5.17.3 of LGIA**	**Interconnection Customer**	**Within 30 days after final invoice (Milestone 22)**	**§ 5.17.3 of LGIA**
10	**Commit to the ordering of long lead time material for Interconnection Facilities**	**Interconnection Customer**	**N/A**	**§ 7.5 of LGIP**
11A	**Provide initial design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner**	**Interconnection Customer**	**By September 1, 2014**	**§ 5.10.1 of LGIA** **§ 7.5 of LGIP**
11B	**Provide comments on initial design, engineering and specification for Interconnection Customer's Interconnection Facilities**	**Interconnecting Transmission Owner**	**Within 30 Calendar Days of receipt**	**§ 5.10.1 of LGIA** **§ 7.5 of LGIP**

12A	**Provide final design, engineering and specification for Interconnection Customer's Interconnection Facilities to Interconnecting Transmission Owner**	**Interconnection Customer**	**By December 1, 2014**	**§ 5.10.1 of LGIA** **§ 7.5 of LGIP**
12B	**Provide comments on final design, engineering and specification for Interconnection Customer's Interconnection Facilities**	**Interconnecting Transmission Owner**	**Within 30 Calendar Days of receipt**	**§ 5.10.1 of LGIA** **§ 7.5 of LGIP**
13	**Deliver to Transmission Owner "as built" drawings, information and documents regarding Interconnection Customer's Interconnection Facilities**	**Interconnection Customer**	**Within 120 Calendar Days of Commercial Operation date**	**§ 5.10.3 of LGIA**
14	**Provide protective relay settings to Interconnecting Transmission Owner for coordination and verification**	**Interconnection Customer**	**By March 1, 2015**	**§§ 5.10.1 of LGIA**
15	**Commencement of construction of**	**Interconnecting**	**30 days after receipt of written**	**§ 5.6 of LGIA**

	Interconnection Facilities	**Transmission Owner**	**authorization to proceed by Interconnection Customer**	
16	**Submit updated data "as purchased"**	**Interconnection Customer**	**No later than 180 Calendar Days prior to Initial Synchronization Date**	**§ 24.3 of LGIA**
17	**In Service Date**	**Interconnection Customer**	**By June 1 , 2016**	**§ 3.3.1 and 4.4.5 of LGIP, § 5.1 of LGIA**
18	**Initial Synchronization Date**	**Interconnection Customer**	**By November 1, 2016**	**§ 3.3.1, 4.4.4, 4.4.5, and 7.5 of LGIP**
19	**Submit supplemental and/or updated data – "as built/as-tested"**	**Interconnection Customer**	**Prior to Commercial Operation Date**	**§ 24.4 of LGIA**
20	**Commercial Operation Date**	**Interconnection Customer**	**By December 31, 2016**	**§ 3.3.1, 4.4.4, 4.4.5, and 7.5 of LGIP**
21	**Deliver to Interconnection Customer "as built" drawings, information and documents regarding Interconnecting Transmission Owner's Interconnection Facilities**	**Interconnecting Transmission Owner**	**Within 120 days of Commercial Operation Date**	**§ 5.11 of LGIA**
22	**Provide Interconnection Customer final cost**	**Interconnecting**	**Within 6 months of completion of**	**§ 12.2 of LGIA**

	invoices	**Transmission Owner**	**construction of Interconnecting Transmission Owner Affiliate Interconnection Facilities**	

*** See Appendix C, Table 3 – Summary of Prepayments**

3. Milestones Applicable Solely for Long Lead Facility Treatment. In addition to the Milestones above, the following Milestones apply to Interconnection Customers requesting Long Lead Facility Treatment: None.

APPENDIX C TO LGIA

Interconnection Details

1. Description of Interconnection:

Interconnection Customer shall install a 30 MW Large Generating Facility, rated at 30 MW gross and 29 MW net, with all studies performed at or below these outputs, and will be located in Block Island Sound, Rhode Island. The Generating Facility is comprised of five (5) fully-inverted wind turbine generators connected in series and rated at 6.0 MW each. The Parties agree that the inverter controls in each wind turbine generator shall satisfy the Generator Governor requirement set forth in Section 9.6.2.2 of this LGIA.

The Large Generating Facility shall receive:

> **Interconnection Service at a level not to exceed 30 MW gross and 29 MW net for Summer and 30 MW gross and 29 MW net for Winter.**

2. Detailed Description of Generating Facility and Generator Step-Up Transformer, if applicable:

Generator Data	
Number of Generators	**5**
Manufacturer	**Alstom or comparable**
Model	**SWT 6.0-154 or comparable**
Designation of Generator(s)	**Haliade -150**
Excitation System Manufacturer	**Alstom Inverter Technology**
Excitation System Model	**Alstom Inverter Technology**
Voltage Regulator Manufacturer	**Alstom Inverter Technology**
Voltage Regulator Model	**Alstom Inverter Technology**
Generator Ratings	
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 90 Degrees F	**6.0/5.9**
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 50 Degrees F	**6.0/5.9**
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above 20 Degrees F	**6.0/5.9**
Greatest Unit Gross and Net MW Output at Ambient Temperature at or above zero Degrees F	**6.0/5.9**
Station Service Load For Each Unit	**__.1_ MW + j_.075__ MVAR**
Overexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • PF = ±0.90 (at 34.5kV)
Underexcited Reactive Power at Rated MVA and Rated Power Factor	The PF range: • PF = ±0.87 (at 0.9kV) • • PF = ±0.90 (at 34.5kV)

Generator Short Circuit and Stability Data	
Generator MVA rating	6.5MVA– inverter technology
Generator AC Resistance	Inverter Technology 0.724 (0 …20ms) 99999 (LVRT ... ∞) *See Note Below
Subtransient Reactance (saturated)	Programmed – inverter technology
Subtransient Reactance (unsaturated)	Programmed – inverter technology
Transient Reactance (saturated)	Programmed – inverter technology
Negative sequence reactance	Programmed – inverter technology
Generator Step-up Transformer Data	
Number of units	5
Self Cooled Rating	6.5MVA
Maximum Rating	6.5MVA
Winding Connection (LV/HV)	0.9kV/34.5kV
Fixed Taps	±2 x 2.5%
Z1 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Positive Sequence X/R ratio primary to secondary Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Z0 primary to secondary at self cooled rating Z_{base}= (34.5kV)^2 / 6.5MVA	0.002949 + j·0.020621 • U_k(%)=6.2 • P_{cu}(kW)=57
Project Grounding Transformer Data	
Number of units	1
Self Cooled Rating	n.a.
Maximum Rating	1.5 MVA @ 10 sec
Winding Connection (LV/LV/HV)	
Fixed Taps	none
Z1 primary to secondary at self cooled	Consistent with Section 3.E below

rating	
Positive Sequence X/R ratio primary to secondary	Consistent with Section 3.E below
Z0 primary to secondary at self cooled rating	Consistent with Section 3.E below

*Note: These are typical characteristic data for synchronous machines. Converter based wind turbines depend heavily in the converter control for the maximum currents and stability analysis.

An equivalence (to obtain the synchronous machine parameters) has been performed with the maximum short circuit currents from the converters in 100% voltage dip considering that the short circuit has 3 steps: a subtransient from the dip until 20ms, a transient between 20 ms until the LVRT (aprox. 150ms) and the steady-state value from the LVRT to the end of simulation.

3. Meteorological and Forced Outage Data Requirements for a Generating Facility that is an Intermittent Power Resource:

An Interconnection Customer whose Generating Facility is an Intermittent Power Resource having wind as the energy resource (referred to here in as “Wind Plant”) will be required to provide the following meteorological and forced outage data to the System Operator in the manner specified in the ISO New England Operating Documents. Capitalized terms in this Appendix C.3 that are not defined in Section 1 of the Agreement shall have the meanings specified in the ISO New England Operating Documents.

A. Static Plant Data

Below are the static plant data requirements that describe the physical layout of the Wind Plant and any associated meteorological equipment as well as data relevant to the design and operation of the Wind Plant. The static plant data must be supplied to the System Operator in the manner specified in the ISO New England Operating Documents. The Interconnection Customer must keep the static plant data current and must inform the System Operator of any proposed datapoints changes.

1) Wind Plant:

a) Wind Turbine tower center coordinates (i.e., latitude and longitude in WGS84 DD-MM-SS.SS using GPS WAAS, or comparable, methodology) and ground elevation of turbines (in meters, to one decimal place).

b) Number of turbines.

c) Turbine model(s) including IEC wind class.

d) Density dependent turbine nominal power curves for each type of turbine in the plant for standard test conditions (e.g., air density equaling 1.225 kg/m^3) and for three additional values of density (for which the density values must be supplied): one power curve for normal operation at the long-term average density expected for the plant and one power curve each for normal operation at approximately 85% (+/- 10%) and approximately 115% (+/-10%), respectively of the expected long-term average Wind Plant air density.

e) Hub height(s) (in meters to one decimal place).

f) Maximum plant nameplate capacity (in MW to two decimal places).

g) Cut-in wind speed(s) and time constants (if any, e.g., windspeed must be above 3.4 m/s for at least 5 minutes, etc.).

h) Cut-out wind speed(s) and time constants (if any).

i) Cut back in wind speed(s) and time constants (if any).

j) Cold temperature cutoff threshold(s) (in Degrees C to one decimal place).

k) High temperature cutoff threshold(s) (in Degrees C to one decimal place).

l) Any cold weather operation packages and their effects on wind turbine operational envelope (e.g. blade and/or gearbox heaters, etc. that extends cold temperature cut-out to below xx degrees, etc.).

m) Wind turbine icing behavior:

i. Triggers for icing related shutdowns (e.g., temperatures, relative humidities, out-of-balance conditions, etc.).

ii. Triggers for release from icing related shutdowns (e.g., manual reset, temperatures, hysteresis, etc.).

n) For all plant wind speed and direction measuring devices (i.e., nacelle-level wind measuring devices):

i. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights) and calibration curves and/or reports.

ii. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data and the mitigation measures employed (e.g., diagram of location with respect to the nacelle and rotor).

o) Descriptions of any permitting or administrative restrictions such as requirements to reduce or to cease power production during certain hours or during certain events or wind conditions.
p) For model training purposes, any available historical information required by the wind power forecaster regarding plant power output, plant meteorological conditions, and conditions that may have caused power output to be below theoretical maximum power output given the experienced wind speeds may also be required to be provided.

2) Met gathering station(s):
a. Center of structure(s) coordinates (using the same method listed above for turbine in the Wind Plant) and ground elevation of met station(s).
b. Equipment type (i.e., model specifications and operating principle e.g. make and model type, measurement heights).
c. Dimensions and/or site plan of any nearby potential obstructions that would substantially reduce the quality of the data (e.g., met-tower dimensions and profile) and the mitigation measures employed (e.g. mounting arm dimensions and orientations).

B. Real-Time Data

Below is the real-time operational and meteorological data requirements for Wind Plant operators that must be provided to the System Operator. The real-time operational and meteorological data must be electronically and automatically transmitted to the System Operator over a secure network using the protocol specified in the ISO New England Operating Documents. This information is required with a high degree of accuracy and reliability.

1) Availability:
The Wind Plant operator's real-time data transfer process and data gathering equipment shall be designated to operate at all times.

2) Required Data:
a) At a minimum, nacelle-level wind speed and wind direction measurements must be provided from the highest wind turbine (i.e., wind turbine hub elevation in terms of elevation above mean sea level) and a minimum of one wind turbine at the maximal value of each of the four true cardinal directions (i.e., the farthest true North, South,

East, and West) in each Wind Turbine Group within the plant. Additionally, the wind turbine nearest the capacity-weighted centroid of the Wind Plant must also report wind speeds and directions. If any wind turbine within a Wind Turbine Group satisfies more than one of these conditions then it may be used to fulfill all conditions that it satisfies (e.g., if the highest wind turbine in a Wind Turbine Group is also the farthest North and the farthest East, it may be used to supply data for all three of these categories). Where more than one turbine satisfies these conditions, preference should be given to those turbines that will be least affected by Wind Plant wake effect from the prevailing wind direction(s). Finally, where a Wind Turbine Group contains 10 or less wind turbines only the nacelle-level data from the highest wind turbine nacelle is required. The locations of wind turbines with nacelle-level equipment providing data must be referenced to the Static Plant Data supplied locations.

b) Ambient temperature, air pressure and relative humidity must be measured, at a minimum, at one location within the plant (preferably as near to the capacity-weighted centroid of the Wind Plant as possible) whose height above ground may be in the range of 2 m to 10 m (or up to 30 m above mean sea level for offshore Wind Plants) and the measurement height above ground (or mean sea level for offshore Wind Plants) must be stated to within 10 cm.

3) Frequency

Minimum frequencies of the real-time data Wind Plant operators must provide are specified in the ISO New England Operating Documents.

C. Outage Coordination

Wind Plants shall submit daily outages in advance to perform routine maintenance work, which in many cases may have no effect on their overall MW capability. Therefore:

1) All Wind Plants must submit Wind Plant Future Availability to the System Operator.

2) If the Wind Plant does not have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, and is not a Qualified Generator Reactive Resource, only Wind Plant Future Availability must be reported to the System Operator.

3) Any Wind Plant that does have a Capacity Supply Obligation in accordance with Market Rule 1, Section III of the Tariff, or that is a Qualified Generator Reactive Resource, must report Wind Plant Future Availability, and also submit an outage request

to the System Operator only when the outage will derate the plant to the point that the available nameplate is less than its Capacity Supply Obligation and/or Qualfied VARs.

4. Other Description of Interconnection Plan and Facilities:

A. Studies

1. Interconnection Feasibility Study: N/A.
2. Interconnection System Impact Study: Completed: Q405 System Impact Study –March 2014;; On April 16, 2014, the Proposed Plan Application received Reliability Committee recommendation for approval by the System Operator.
3. Interconnection Facilities Study: Waived
4. Optional Interconnection Study: None
5. Supplemental System Impact Study: None

B. Interconnection Customer's Interconnection Facilities.

The Interconnection Customer will own the Interconnection Customer's Interconnection Facilities described in Appendix A.1.b to this Agreement.

The Interconnection Customer will engineer, procure, install, own and maintain the telemetering (RTU) equipment and the telecommunication circuits that are installed at the Block Island Substation and which are necessary to interface and communicate with the System Operator Communications Front End (CFE) network and the Interconnecting Transmission Owner's Local Control Center. Once the RTU has been configured by the Interconnection Customer, the Interconnecting Transmission Owner will check the reporting of the Interconnection Customer RTU to ensure that it is sending the appropriate signals to the Local Control Center. ISO-NE will check the RTU telemetry and control signals as required according to the ISO-NE CFE Interface specifications.

Interconnecting Transmission Owner and Interconnecting Transmission

Owner's Affiliate agree to work with the Interconnection Customer and landowner to obtain adequate physical space and the necessary rights of use, rights of way and easements within the Block Island Substation for Interconnection Customer to safely and conveniently install, operate and maintain such data network, power conditioning, operational control, performance monitoring, metering, telemetering and telecommunications equipment as are agreed by the Interconnection Customer and Interconnecting Transmission Owner for the safe and reliable operations of the Generating Facility, which equipment shall be located within the Interconnection Customer's Control Building, as identified in Appendix A-2. Interconnecting Transmission Owner's Affiliate shall be responsible for all site preparation and civil works for such space as part of the Direct Assignment Facilities, but shall have no responsibility for the construction of Interconnection Customer's Control Building or the equipment therein.

Properly accredited representatives of the Interconnecting Transmission Owner shall at all reasonable times have access to the Interconnection Customer's Interconnection Facilities at the transition structure to make reasonable inspections and obtain information required in connection with this Agreement.

Upon notice to the Interconnection Transmission Owner Affiliate's control room, properly accredited representatives of the Interconnection Customer shall at all reasonable times have access to the Interconnection Facilities to make reasonable inspections and obtain information required in connection with this Agreement.

C. Interconnecting Transmission Owner's Interconnection Facilities

The Interconnecting Transmission Owner will own, operate and maintain the Interconnecting Transmission Owner's Interconnection Facilities described in Appendix A.1.c to this Agreement at the Interconnection Customer's expense.

Interconnecting Transmission Owner's Affiliate will own, operate and maintain the Interconnecting Transmission Owner's Affiliate's Interconnection Facilities described in Appendix A.1.c to this Agreement, at the Interconnection Customer's expense.

D. Testing

Testing of the Interconnection Facilities shall be performed by Interconnection Customer. Prior to conducting the tests, Interconnection Customer shall submit the proposed testing protocols to the Interconnecting Transmission Owner's Affiliate. The Interconnecting Transmission Owner's Affiliate shall have the right to review and comment on such proposed testing protocols (the "Test Protocols"). Within ten (10) days after receipt of the Test Protocols from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Protocols or (B) reject the Test Protocols by providing written notice stating the reasons for the rejection and specifying the changes necessary to make the Test Protocols acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Protocols within ten (10) days, then Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Protocols as originally submitted by Interconnection Customer.

At least five (5) days prior to conducting the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate, and Interconnecting Transmission Owner's Affiliate prior to shall have the right to witness the tests.

Following the tests, Interconnection Customer shall notify Interconnecting Transmission Owner's Affiliate of the results of the tests (the "Test Results"). Within ten (10) days after receipt of the Test Results from Interconnection Customer, Interconnecting Transmission Owner's Affiliate shall either (i) accept the Test Results or (B) object to the Test Results by providing written notice stating the reasons for the rejection and specifying its objections and the changes necessary to make the Test Results acceptable to Interconnecting Transmission Owner's Affiliate. If Interconnecting Transmission Owner's Affiliate fails to accept or reject the Test Results within ten (10) days, then Interconnecting Transmission Owner's Affiliate shall be deemed to have accepted the Test Results.

E. Protection Philosophy

Interconnection Transmission Owner and Interconnection Customer shall jointly establish a Protection Philosophy in compliance with Sections 9.6.2.3, 9.7.3, 9.7.4.1, 9.7.4.5 and 9.7.5 of this LGIA which shall be the design basis for the final engineering of the Interconnection Facilities. National Grid Connection Specifications ESB-756 shall be the prevailing guideline for interconnection and protection design development.

4. Special Conditions

A. Cost Responsibility

1. General

Pursuant to the terms of the Agreement, the Interconnection Customer shall be solely responsible for all reasonable costs incurred by the Interconnecting Transmission Owner and its Affiliate as a result of the Direct Assignment Facilities and/or services provided under this Agreement in excess of the estimated costs and charges provided in this Appendix C to this Agreement that are not otherwise recovered under the Tariff.

Such costs are intended to be recovered by, but would not be limited to, the charges specified below.

<u>Interconnection Facilities</u>

The Interconnection Customer shall be responsible for direct assignment facilities charges calculated in accordance with the formulae set forth in Schedule 21 – NEP, Attachment DAF of the OATT as may be in effect from time to time ("DAF Charge"). A copy of the presently effective transmission DAF Charge is provided in Appendix C, Exhibit 1 for illustrative purposes. Estimated Annual DAF Charges are provided in Appendix C, Table 1.

Metering and Related Equipment

The Interconnection Customer will own the revenue meter. The Interconnecting Transmission Owner's Affiliate will own and maintain the appropriate metering transformers, associated test switches, and a remote terminal unit ("RTU") and related equipment. Metering equipment must conform to Tariff and Operating Procedures in effect and amended from time to time, and will be subject to the requirements of the Interconnecting Transmission Owner. The Interconnecting Transmission Owner shall be present during commissioning of the revenue meter and shall have the right to witness any testing of said meter. The Interconnection Customer grants permission to Interconnecting Transmission Owner's personnel from various departments including engineering, distribution planning, transmission planning and T&D, to access any and all Interconnection Customer RTU data which is telemetered to Interconnecting Transmission Owner's control room. Interconnecting Transmission Owner agrees not to share this data with its sales and marketing personnel pursuant to applicable FERC rules and regulations. Additionally, the Interconnecting Transmission Owner agrees not to share this data with anyone other than those listed above without the prior written consent of an officer of the Interconnection Customer.

If, at any time, any metering equipment is found to be inaccurate by the requirements set forth in ISO New England Operating Procedure No. 18 - Metering and Telemetering Criteria, Interconnecting Transmission Owner shall cause such metering equipment to be made accurate or replaced, and meter readings for the period of inaccuracy shall be adjusted so far as the same can be reasonably ascertained, but no adjustment prior to the beginning of the preceding month shall be made except by agreement of the Interconnection Customer and Interconnecting Transmission Owner.

The Interconnecting Transmission Owner and Interconnection Customer shall comply with any reasonable request of the other concerning the sealing of the meters, the presence of a representative of the other party when the seals are broken and the tests are made, and other matters affecting the accuracy of the measurement of electricity delivered from the Generating Facility. If either Interconnecting Transmission Owner or Interconnection Customer believes that there has been a meter failure or stoppage, it shall immediately notify the other.

B. Termination Charge

In addition to the payment obligations specified in Article 2 of this Agreement for termination by the Interconnection Customer prior to the expiration of the term of this Agreement, the Interconnection Customer agrees that it will be responsible for the DAF Charges for the original term of this Agreement as determined in accordance with the formula set forth in Schedule 21 – NEP, Attachment DAF of the OATT or as contained in an alternative cost recovery mechanism that the FERC may have approved at the time of the termination.

The Interconnection Customer reserves its right to initiate or participate in a proceeding before the FERC to contest the reasonableness of the above charges.

C. Station Service

Interconnection Customer shall be responsible for properly arranging its Station Service electric requirements, including, auxiliary service or backup service.

D. Regulatory Compliance

The Parties agrees to provide each other with notices and copies of all filings, including any applicable FERC filings pertaining to the Interconnection Facilities and/or this Agreement.

E. Radial Service

Interconnection Customer understands that the source to the 34.5kV Block Island substation is a radial feed from the Interconnecting Transmission Owner's Affiliate Wakefield Substation and that there will be an interruption to interconnection service whenever the feeder breaker at Wakefield or the Block Island Transmission System is unavailable. Interconnecting Transmission Owner or its Affiliate will notify Interconnection Customer of any planned interruption in service prior to such interruption and of any unplanned interruption as soon as reasonably practicable.

F. Losses

The metering equipment shall be compensated internally in order to record the delivery of electricity in a manner that accounts for any energy losses occurring between the Metering Point and the Point of Interconnection both when the Large Generating Facility is delivering energy to the Point of Interconnection and when Station Service power is delivered to the Point of Interconnection for the benefit of the Interconnection Customer, consistent with ISO New England Operating Documents, Applicable Reliability Standards, or successor documents or procedures.

G. Payment Schedule and Financial Security Requirements

Interconnection Customer shall make prepayments to the Interconnecting Transmission Owner for the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnecting Transmission Owner's

Affiliate Interconnection Facilities by wire transfer in immediately available funds in accordance with the payment schedule in Appendix C, Table 3 of this Agreement.

1. The Summary Table of Prepayments as shown in Appendix C, Table 3 sets forth four (4) prepayments (“Prepayments”).

2. The sum of the four prepayments made by Interconnection Customer shall be referred to as the "Total Estimated Cost". Within six (6) months following the In-Service Date, Interconnecting Transmission Owner shall inform Interconnection Customer of the final actual costs to design and install the Interconnecting Transmission Owner's Interconnection Facilities and Interconnecting Transmission Owner’s Affiliate Interconnection Facilities ("Final Actual Installed Cost"), plus the actual tax gross up amount, as calculated by the Interconnecting Transmission Owner in accordance with the formula described in Article 5.17.4 of this Agreement ("Actual Tax Gross Up Amount") and shall provide Interconnection Customer with a final written invoice ("Final Invoice") for the difference between the Final Actual Installed Cost and the Total Estimated Cost ("Final Balance").

On or before thirty (30) days following the date of the Interconnecting Transmission Owner's Final Invoice, the Interconnection Customer shall pay the Final Balance to Interconnecting Transmission Owner by wire transfer in immediately available funds; provided that, subject to compliance with Article 12.2 of this Agreement, in the event that the Total Estimated Cost exceeds the Final Actual Installed Cost, any such excess amount shall be refunded to Interconnection Customer as an overpayment.

3. The Interconnecting Transmission Owner shall not be obligated to commence and may not commence any of the tasks listed in Appendix B of this Agreement until (i) the Interconnecting Transmission Owner has received written notice from Interconnection Customer to proceed with such tasks, and (ii) the Interconnecting Transmission Owner has received

the Prepayment required under this Section G corresponding to such task listed in Appendix B.

4. The Interconnection Customer and Interconnecting Transmission Owner agree that the Final Actual Installed Cost shall be considered a construction advance for tax purposes except as otherwise provided in Article 5.17.5 of this Agreement. On or before the date that Interconnection Customer pays the Interconnecting Transmission Owner's Final Invoice, Interconnection Customer shall present to the Interconnecting Transmission Owner a Letter of Credit ("LOC"), in form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed, in a face amount representing the estimated tax gross up amount on the Final Actual Installed Cost. For purposes of this Agreement, the Actual Tax Gross Up Amount shall be the product of (i) the Final Actual Installed Cost and (ii) the Interconnecting Transmission Owner's or its Affiliate's tax gross up rate in existence at the In-Service Date as shown in Appendix C, Table 1 of this Agreement.

5. The Interconnection Customer shall be responsible for all costs associated with the LOC, including, without limitation, the costs of obtaining, maintaining and replacing such LOC and reimbursement of the LOC Bank (as such term is defined below). Each LOC shall be in a form and substance complying with the requirements of this Section G and also acceptable to the Interconnecting Transmission Owner, such acceptance not to be unreasonably withheld or delayed. Each LOC shall be an irrevocable, unconditional, and transferable standby letter of credit issued by a U.S. commercial bank or a U.S. branch of a foreign bank (the "LOC Bank") provided that the Interconnection Customer is not an affiliate of the LOC Bank, the LOC Bank has at least ten billion dollars ($10,000,000,000) in assets and the LOC Bank's lowest credit rating is at least A2 from Moody's Investors Service or A from Standard and Poor's Ratings Services or Fitch, Inc. ("LOC Bank Requirement(s)"). If at any time (i) the LOC Bank fails to satisfy any LOC Bank Requirement, or (ii)

the LOC Bank advises that it will not renew the LOC beyond its current expiration date ("Notice of Cancellation"), then, the Interconnection Customer shall deliver a replacement letter of credit from a bank meeting the LOC Bank Requirements and the other requirements of this Paragraph and this Agreement. Such replacement letter of credit shall be delivered to Interconnecting Transmission Owner promptly but in no event later than ten (10) Calendar Days following the date on which the LOC Bank's first fails to satisfy an LOC Bank Requirement or, in the case of a Notice of Cancellation, thirty (30) Calendar Days prior to the current expiration date of the applicable LOC. If Interconnection Customer fails to provide such replacement LOC by the applicable date contemplated by this paragraph (and in compliance with the other requirements hereof), Interconnecting Transmission Owner shall have the immediate right to draw the full amount remaining under the applicable existing LOC.

6. Any LOC delivered pursuant to this Section G, as such LOC may be replaced, modified, or amended, from time to time, as contemplated above, shall serve as security for Interconnection Customer's obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as a result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner under or in connection with this Agreement for the tax gross up on the cost of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, and Interconnecting Transmission Owner's Affiliate Interconnection Facilities and shall not be used for any other purpose.

7. Interconnection Customer shall maintain the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in full force and effect at all times; provided, however, that Interconnection Customer may terminate such LOC, any modification or amendment thereof, and any replacement for such LOC, only upon termination of Interconnection Customer's indemnification

obligation in accordance with Article 5.17.3 of this Agreement. The Interconnecting Transmission Owner shall have the right to draw upon the LOC provided under this Section G, any modification or amendment thereof, and any replacement for such LOC, in the event the Interconnection Customer fails to timely meet any of its obligations under this Agreement with respect to payment of, or indemnification of Interconnecting Transmission Owner or its Affiliate from and against, the cost consequences of any tax liability imposed upon or against Interconnecting Transmission Owner or its Affiliate as the result of payments or property transfers made by Interconnection Customer to Interconnecting Transmission Owner or its Affiliate under or in connection with this Agreement, as well as any interest and penalties.

8. If Interconnection Customer fails to make any payments required under this Appendix C or the Agreement, or fails to provide and maintain the security contemplated above, each in the form, amounts, and at the times, required, Interconnecting Transmission Owner or its Affiliate may exercise any rights, and pursue any remedies, available to it under this Agreement, including, without limitation, Article 12. If any payment date or other due date specified in this Section G falls on a weekend or a federal bank holiday, then such payment or due date shall be deemed to be the next business day.

APPENDIX C

EXHIBIT 1
Transmission DAF Charge
Monthly Rate Formula

The Monthly Rate shall equal the Annual Facilities Charge divided by 12.

The Annual Facilities Charge shall be calculated in a manner consistent with Schedule 21 - NEP, Attachment DAF of the OATT, determination of the Annual Facilities Charge for transmission facilities, which section of Schedule 21 currently provides as follows:

"The Annual Facilities Charge shall equal the product of the year-end Gross Plant Investment associated with the facility and the average Annual Transmission Carrying Charge, for the life of the facility."

"The Gross Plant Investment shall be the investment from the plant accounting records associated with the facility."

"The average Annual Transmission Carrying Charge shall be the Annual Transmission Revenue Requirement as determined in Attachment RR, Sections I. (A) through I. (H) to this Schedule, divided by the year-end balance of total transmission plant investment determined in accordance with Attachment RR, Section I. (A) (1) (a)."

"To the extent that the Transmission Customer provides a Contribution in Aid of Construction the average Annual Transmission Carrying Charge calculation will be modified to exclude Sections I. (A) (1) (a), I. (A) (1) (d), I. (A) (1) (e), I. (A) (1) (f), I (B), and I. (C) of Attachment RR, Exhibit 1 of Schedule 21 - NEP."

"If the Interconnection Customer permanently terminates service in advance of the term of its Agreement, the Interconnection Customer may, at its option, close out its continuing obligation to pay the Annual Facilities Charge by paying NEP a lump sum payment equal to the net present value of the Return and Depreciation Expense on the net book value of the facility at the time of termination that would have been collected over the remaining life of the facility, plus any cost of removal if applicable. The return shall be equal to that found in Attachment RR, Exhibit 1, Section I.(A)(2) to Schedule 21 - NEP, in the year of termination. Depreciation Expense shall be based on a straight-line method. The discount rate in the net present value calculation shall be equal to the interest rate pursuant to Section 35.19(a) of the Commission's regulations effective at the time of termination."

"Billings in accordance with this Schedule shall initially be based upon estimates calculated based on actual costs in the preceding year, such estimates being adjusted to actual as soon as practicable after such costs become known. The source of the data shall be NEP's accounting records."

APPENDIX C

Table 1 – Estimated Annual DAF Charges

The costs listed in this Appendix C, Table 1 are the estimates provided in Table 2 and are provided for illustrative purposes only. The DAF Charge will be adjusted to reflect the Final Actual Installed Cost and the Actual Annual Transmission Carrying Charges as determined from year to year. In the event that the Project is terminated, Interconnecting Transmission Owner shall refund to Interconnection Customer all Prepayments received in excess of Interconnecting Transmission Owner's expenses and payment obligations incurred in fulfillment of this Agreement.

Components	Estimated Cost
Pre-design*	$50,000
Design ITO Affiliate's Interconnection Facilities	$347,500
Procure ITO Affiliate's Interconnection Facilities	$662,500
Construct ITO Affiliate's Interconnection Facilities	$1,590,000
Estimated Total Customer Payments (see Tables 2 & 3)	$2,650,000
Tax Gross Up (0.3554[1] x Total Customer Payments)	$941,810

*A limited notice to proceed to be issued upon execution of this agreement will authorize initial expenditures not to exceed $50,000 and to be reimbursed no later than September 1, 2014.

Estimated Annual DAF Charge[2]

Gross Plant Investment (w/out tax gross up)	$2, 650,000
Times	
Annual Carrying Charge Rate	7.48%
Equals	
Annual DAF Charge	$198,220

APPENDIX C

Table 2 – Estimated Cost of Interconnection Facilities for DAF Charges

Interconnection Facility	Total Estimated Cost	% of Total	Interconnection Customer Cost
34.5kV breaker at POI	$2,500,000*	20%	$500,000
Grounding transformer	$500,000	100%	$500,000
34.5kV overhead circuit	$300,000**	50%	$150,000
34.5kV underground circuit	$3, 000,000**	50%	$1,500,000
Total	$5,800,000		$2, 650,000

* Estimated cost of five breaker switchgear arrangement at Block Island Substation

** The Interconnection Customer is only responsible for the cost of the generator lead between the Point of Change of Ownership and the Point of Interconnection. A second 34.5kV line is for the tie of the Block Island Substation to the mainland, which is being funded outside of this Agreement. The two lines are running in parallel ductbanks from the shore and on common poles on the Block Island property. They were estimated together and a cost of one-half the total is used as a proxy cost for either line.

Table 3 – Summary Table of Prepayments

Date	% of Total	Amount
Milestones 8and7C2	**15%**	**$397,500**
Milestone 7C3	**25%**	**$662,500**
Milestone 7C4	**60%**	**$1,590,000**

Total	**$2,650,000**

APPENDIX D TO LGIA

Security Arrangements Details

Infrastructure security of the New England Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day New England Transmission System reliability and operational security. The Commission will expect System Operator, Interconnecting Transmission Owners, market participants, and Interconnection Customers interconnected to the New England Transmission System to comply with the recommendations offered by the Critical Infrastructure Protection Committee and, eventually, best practice recommendations from NERC. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

APPENDIX E TO LGIA

Commercial Operation Date

This Appendix E is a part of the LGIA between System Operator, Interconnecting Transmission Owner and Interconnection Customer.

[*Date*]
New England Power Company
Attn: Director, Transmission Commercial
East Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

Generator Interconnections
Transmission Planning Department
ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Re: Block Island Wind Farm Large Generating Facility

Dear _______________:

On [Date] Deepwater Block Island Wind, LLC has completed Trial Operation of Unit No. ___. This letter confirms that Deepwater Block Island Wind, LLC commenced commercial operation of Unit No. ___ at the Large Generating Facility, effective as of [Date plus one day].

Thank you.

[*Signature*]

[*Interconnection Customer Representative*]

APPENDIX F TO LGIA

Addresses for Delivery of Notices and Billings Notices:

System Operator: N/A

Interconnecting Transmission Owner:

New England Power Company
Attn: Director, Transmission Commercial
West Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

With copy to:
New England Power Company
Attn: Lead Account Manager
West Wing, Floor 1
40 Sylvan Road
Waltham, MA 02451

Interconnection Customer:

Deepwater Block Island Wind, LLC
C/O Deepwater Wind, LLC
Attn: Chris van Beek, President
56 Exchange Terrace, Suite 101
Providence, RI 02903

Billings and Payments:

System Operator: N/A

Interconnecting Transmission Owner:

New England Power Company
Attn: Transmission Billing
West Wing, Floor 2
40 Sylvan Road
Waltham, MA 02451

Interconnection Customer:

Deepwater Block Island Wind, LLC
C/O Deepwater Wind, LLC
Attn: Contract Admin
56 Exchange Terrace, Suite 101
Providence, RI 02903

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

System Operator: N/A

Interconnecting Transmission Owner:

Telephone: (781) 907-2409
Fax: (781) 296-8088
Email: edward.m.kremzier@nationalgrid.com

Interconnection Customer:

Telephone: (401)-648-0606
Fax: (401)-228-8004
Email: kadmin@dwwind.com

DUNS Numbers:

Interconnection Customer: 831810895
Interconnecting Transmission Owner: 006952881

APPENDIX G TO LGIA

Interconnection Requirements For A Wind Generating Plant

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this LGIA continue to apply to wind generating plant interconnections.

A. Technical Standards Applicable to a Wind Generating Plant

i. Low Voltage Ride-Through (LVRT) Capability

A wind generating plant shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

Transition Period LVRT Standard

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to

the transmission interconnection voltage or “GSU”), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT. Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The

clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the System Operator and Interconnecting Transmission Owner. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.

3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.

4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.

5. Existing individual wind generator units that are, or have been, interconnected to the network at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual wind generator units that are replaced are required to meet the Appendix G LVRT Standard.

ii. Power Factor Design Criteria (Reactive Power)

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this LGIA, if the Interconnection System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the System Operator and Interconnecting Transmission Owner, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind generating plant is in operation. Wind generating plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the Interconnection System Impact Study shows this to be required for system safety or reliability.

iii. Supervisory Control and Data Acquisition (SCADA) Capability

The wind generating plant shall provide SCADA capability to transmit data and receive instructions from the System Operator and Local Control Center to protect system reliability. The System Operator, Interconnecting Transmission Owner and the wind generating plant Interconnection Customer shall determine what SCADA information is essential for the proposed wind generating plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

Document Content(s)