Andrew S. Marcaccio
Senior Counsel

March 19, 2021

VIA ELECTRONIC MAIL

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

RE: Docket 5127 – 2021 Annual Retail Rate Filing
Responses to PUC Data Requests – Set 2 (Complete Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please find the Company's responses to the Public Utilities Commission's ("PUC") Second Set of Data Requests ("Complete Set") in the above-referenced docket. [2]

In addition to the responses that the Company already submitted on March 12, 2021, this transmittal contains the remaining response in this set (PUC 2-5). This transmittal also includes the attachment for PUC 2-9 which was inadvertently left out of the filing made on March 12, 2021. This transmittal completes the Company's responses to the PUC's Second Set of Data Requests.

Thank you for your attention to this filing. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5127 Service List
John Bell, Division
Al Mancini, Division
Leo Wold, Esq.

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[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by five hard copies filed with the Clerk within 24 hours of the electronic filing.
[2] In addition, the Company will deliver to the Commission six, three-hole punched hard copies of PUC Set with Bates stamp.

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.

________________________________ March 19, 2021

Joanne M. Scanlon Date

National Grid – 2021 Annual Retail Rate Filing - Docket No. 5127
Service List Updated 2/15/2021

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PUC 2-1

Request:

When calculating the LRS Administrative Cost Factors proposed in Schedule NG-4 of the 2021 Retail Rate Filing, it appears that National Grid based its estimate of commodity related uncollectible expense on the currently effective 2020 RES charge, among other charges. Please re-calculate the LRS Administrative Cost Factors using the RES charge proposed in Docket No. 5096, and update pages 1 and 2 of Schedule NG-4 to reflect those changes. (At this time, it is not necessary to update any schedules other than pages 1 and 2 of Schedule NG-4.)

Response:

Please see Attachment PUC 2-1, which provides an illustrative re-calculation of Last Resort Service Uncollectible Expense estimates, using the RES Charge which was proposed in the Company's RES Charge and Reconciliation filing, submitted on February 25, 2021 in Docket No. 5096.

In the process of reviewing this response, it was discovered that the footnote in Schedule NG-4, Page 2 for column (e) contained an incorrect Commercial Group base rate of 6.580¢/kWh. The correct rate is 5.667¢/kWh. The footnote has been corrected in Attachment 2-1. Please note that the calculations in both Schedule NG-4, and in this attachment, were made using the correct rate of 5.667¢/kWh.

Prepared by or under the supervision of: Adam S. Crary

The Narragansett Electric Company
ILLUSTRATIVE CALCULATION OF LAST RESORT SERVICE ADMINISTRATIVE COST FACTOR
For the Period April 1, 2021 through March 31, 2022

		Total (a)	Residential (b)	Commercial (c)	Industrial (d)
(1)	Illustrative Estimated Commodity Related Uncollectible Expense for 2021	$3,626,413	$2,614,189	$856,024	$156,200
(2)	Estimated Other Administrative Expense for 2021	$3,911,454	$2,916,313	$820,006	$175,135
(3)	Illustrative Estimated Total Administrative Expense for 2021	$7,537,867	$5,530,502	$1,676,030	$331,335
(4)	Forecasted LRS kWh for the period of April 1, 2021 through March 31, 2022	3,867,694,410	2,721,129,582	954,318,654	192,246,174
(5)	Illustrative Estimated LRS Administrative Cost Factor		$0.00203	$0.00175	$0.00172
(6)	LRS Administrative Cost Reconciliation Adjustment Factor		$0.00033	$0.00033	$0.00027
(7)	Illustrative LRS Administrative Cost Factor effective April 1, 2021		$0.00236	$0.00208	$0.00199

(1) Page 2, line (16)
(2) Schedule NG-4, Page 3, line (4)
(3) Line 1 + Line 2
(4) Schedule NG-3, Page 2, Line (4)
(5) Line 3 ÷ Line 4, truncated to 5 decimal places
(6) Schedule NG-7, Page 1, Lines (5), (10), and (15)
(7) Line (5) + Line (6)

The Narragansett Electric Company
ILLUSTRATIVE CALCULATION OF LAST RESORT SERVICE ADMINISTRATIVE COST FACTOR
For the Period April 1, 2021 through March 31, 2022

Section 1: Illustrative Estimated Commodity Cost/Revenue for April 1, 2021 through March 31, 2022

		Residential Customer Group			Commercial Customer Group			Industrial Customer Group			Total Estimated
		Estimated LR kWhs	Estimated LR Rate	Estimated LR Cost/Rev	Estimated LR kWhs	Estimated LR Rate	Estimated LR Cost/Rev	Estimated LR kWhs	Estimated LR Rate	Estimated LR Cost/Rev	LR Cost/Revenue
		(a)	(b)	(c)=(a) x (b)	(d)	(e)	(f)=(d) x (e)	(g)	(h)	(i)=(g) x (h)	(j)= (c) + (f) + (i)
(1)	Apr-2021	219,312,681	$0.07390	$16,207,207	79,231,148	$0.06900	$5,466,949	15,944,725	$0.06514	$1,038,639	$22,712,795
(2)	May-2021	172,348,574	$0.07390	$12,736,560	71,674,358	$0.06900	$4,945,531	14,790,649	$0.05853	$865,697	$18,547,788
(3)	Jun-2021	200,928,500	$0.07390	$14,848,616	77,333,910	$0.06900	$5,336,040	15,810,959	$0.04943	$781,536	$20,966,192
(4)	Jul-2021	278,774,758	$0.07390	$20,601,455	89,818,884	$0.06900	$6,197,503	18,107,192	$0.05240	$948,817	$27,747,775
(5)	Aug-2021	297,990,236	$0.07390	$22,021,478	92,082,386	$0.06900	$6,353,685	18,484,773	$0.04942	$913,517	$29,288,680
(6)	Sep-2021	260,559,980	$0.07390	$19,255,383	86,586,291	$0.06900	$5,974,454	17,390,095	$0.04896	$851,419	$26,081,256
(7)	Oct-2021	184,017,837	$0.07390	$13,598,918	77,267,759	$0.06900	$5,331,475	15,647,583	$0.04832	$756,091	$19,686,484
(8)	Nov-2021	180,749,703	$0.07390	$13,357,403	72,804,843	$0.06900	$5,023,534	14,747,197	$0.05838	$860,941	$19,241,878
(9)	Dec-2021	224,895,829	$0.07390	$16,619,802	77,696,045	$0.06900	$5,361,027	15,482,038	$0.07370	$1,141,026	$23,121,855
(10)	Jan-2022	247,382,378	$0.07390	$18,281,558	79,402,662	$0.06900	$5,478,784	15,683,241	$0.09165	$1,437,369	$25,197,711
(11)	Feb-2022	230,890,283	$0.07390	$17,062,792	75,381,478	$0.06900	$5,201,322	15,019,549	$0.08898	$1,336,439	$23,600,553
(12)	Mar-2022	223,278,823	$0.07390	$16,500,305	75,038,890	$0.06900	$5,177,683	15,138,173	$0.07160	$1,083,893	$22,761,881
(13)	Total	2,721,129,582		$201,091,477	954,318,654		$65,847,987	192,246,174		$12,015,384	$278,954,848

Section 2: Estimated Commodity-Related Uncollectible Expense for April 1, 2021 through March 31, 2022

		Residential	Commercial	Industrial	Total
(14)	Estimated Rate Year Cost/Revenue	$201,091,477	$65,847,987	$12,015,384	
(15)	Uncollectible Rate	1.30%	1.30%	1.30%	
(16)	Rate Year Commodity-Related	$2,614,189	$856,024	$156,200	$3,626,413

Section 1:
Columns (a), (d) and (g), Lines (1) through (12) = Schedule ASC-3, Page 2
Column (b): the sum of the proposed April 1, 2021 base Last Resort Service rate of 7.237¢ (Docket No. 4978, filed January 15, 2021, Attachment 1, Page 3, Line (11), Column (g)), the proposed 2021 RES rate of 0.665¢, and the proposed LRS Adjustment charge of (0.512¢)
Column (e): the sum of the proposed April 1, 2021 base Last Resort Service rate of 6.580¢ (Docket No. 4978, filed January 15, 2021, Attachment 1, Page 4, Line (10), Column (g)), the proposed 2021 RES rate of 0.665¢, and the proposed LRS Adjustment charge of 0.568¢
Column (h): the sum of the proposed April 1, 2021 through June 30, 2021 base Last Resort Service rates (Docket No. 4978, filed January 15, 2021, Attachment 1, Page 6, Line (1)), the proposed 2021 RES rate of 0.665¢, and the proposed LRS Adjustment charge of (0.598¢). The July-2021 through Mar-2022 estimated LRS Base charges are based on the actual July-2020 through Mar-2021 SOS/LRS base charges

Section 2:
(14) Line (13)
(15) Uncollectible rate approved in Docket No. 4770
(16) Line (14) x Line (15)

PUC 2-2

Request:

Referencing National Grid's response to PUC 1-2(c), please define "wholesale monthly load forecast" and explain how National Grid estimates it. In your response, please note whether and how (if applicable) the "wholesale monthly load forecast" relies on the monthly electric deliveries forecast.

Response:

The wholesale monthly load is the reconciled actual load for Standard Offer Service as reported to ISO-NE. The wholesale monthly load forecast is the forecasted future load for this Standard Offer Service.

The wholesale monthly load forecast relies on the monthly electric deliveries forecast. The Company first develops the monthly electric deliveries forecast and derives the expected annual growth rate for each month. The Company then applies the expected annual growth rate to the current year's wholesale monthly load to estimate next year's wholesale load forecast for the corresponding month.

Prepared by or under the supervision of:
James Ruebenacker, Shira Horowitz, Joseph Gredder, and Jingrui Xie

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PUC 2-3

Request:

Referencing the Percentage Difference table in National Grid's response to PUC 1-2(c), please explain why actual Capacity Settlement for the Commercial group was consistently 14-15% higher than estimated Capacity Settlement for the months of January – March 2020, and why such consistently high Percentage Differences in monthly Capacity Settlements was limited to January – March.

Response:

The Company estimates the capacity settlement for each customer group for each month by estimating the various inputs in the ISO-NE capacity settlement calculation. One of the inputs in the calculation is the Customer Average Peak Contribution (also known as the ICAP tags), which is determined by the load coincident with the ISO-NE system peak in the prior calendar year. While the Customer Average Peak Contribution for all National Grid distribution load is the same throughout a given capacity year, the Customer Peak Contribution fluctuates daily for each load asset as customers migrate to and from Standard Offer Service ("SOS").

The Company estimates the capacity settlement at the time of each SOS rate filing. January through March 2020 was part of the winter SOS rate period which was filed on July 19, 2019. The Company used the Commercial Group's ICAP tag from June 30, 2019 as its estimate for each month of the winter SOS rate period because it is the same capacity year. However, the average of the actual ICAP tags for January through March 2020 were over 11% higher than the estimated ICAP tags for the period. This resulted in capacity settlement for January through March that was 14-15% higher than estimated capacity settlement.

The summer SOS rate period, which was April through September 2020, included a new estimated ICAP tag in the estimated capacity settlement. The actual ICAP tags for this period were closer to the estimated ICAP tags resulting in smaller deviations between estimated and actual capacity settlement. This also occurred for the next winter rate period which began on October 2020.

Prepared by or under the supervision of: James Ruebenacker

PUC 2-4

Request:

Referencing the Percentage Difference table in National Grid's response to PUC 1-2(c), please explain why actual Load for the Residential group was consistently higher than estimated Load for the months of April – October 2020, with the most significant Percentage Differences occurring in the summer months. In your response, please note whether this phenomenon of actual Load being significantly higher than estimated Load during summer months was isolated to 2020 or is representative of a multi-year trend.

Response:

The actual residential load was higher than the estimated load for the months of April – October 2020. However, this is not representative of a multi-year trend.

The COVID-19 pandemic has caused more people to stay at home in 2020. This contributed to higher residential energy consumption in 2020. However, these increases in energy were not linear across different months. Hot summer weather typically drives up the energy used for cooling needs. The 2020 summer months' (July and August) Cooling Degree Days ("CDD") were 7.8% higher than the same period of the previous year. The higher the CDDs are, the more energy is expected to be used for cooling. Thus, the hot summer also boosted the residential energy consumption for the summer months in 2020.

Prepared by or under the supervision of:
James Ruebenacker, Shira Horowitz, Joseph Gredder, and Jingrui Xie

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<u>PUC 2-5</u>

<u>Request</u>:

Referencing National Grid's response to PUC 1-6, please explain the following:

a. In the 3 rate case years included in the coincident peak allocator calculation, how specifically did National Grid derive and extrapolate each rate class's 12 CP load factor "from coincident peak data from results of the Company's load research study"? Describe the methodology and data used.

b. Were the 12 CP load factors from the 3 most recent rate case years all derived from a single load research study, or was there 3 different load research studies?

c. If there were different load research studies, please describe how the study methodologies and/or input data changed between them.

<u>Response</u>:

a. Schedule NG-11 shows for each of the three test years and for each rate class, the Load Factor at 12CP ("Load Factor"). The Company uses the following data sources in developing this:

   1) the Company's sales history (i.e., for total monthly billed kWh and number of customers and in each rate class or rate class group), and
   2) the Company's load research class average load shapes (i.e., for the typical customer's hourly usage in each rate class).

   In terms of methodology, each "Load Factor" in Schedule NG-11, Columns (c), (f), and (i) is a ratio, "Average Hourly Sales Divided by Peak Hourly Sales" computed as follows:

   1) "Average Hourly Sales" equals Rate Class Annual Sales divided by 8,760, the number of hours in a year. Schedule NG-11, Columns (a), (d), and (g) (annual kWh for each of the 12-month periods) is the Rate Class Annual Sales. The source for this data is Company billed kWh history, as stated above.
   2) "Peak Hourly Sales" equals the average of 12 Rate Class Monthly Coincident Peak loads; these each equal the monthly Coincident Hourly Peak Demand (from the load research class average load shape) multiplied by the number of customers. Schedule NG-11, Columns (b), (e), and (h), "Class 12 CP," is the average of 12 Rate Class Monthly Coincident Peak loads. The source for this data is Company sales history and load research class average load shapes, as stated above.

Prepared by or under the supervision of: Adam S. Crary

PUC 2-5, page 2

b. The 12 CP load factors were all derived from a single ongoing load research study which has spanned that timeframe covered by the three most recent rate cases.

c. Please see response to part b. above.

Prepared by or under the supervision of: Adam S. Crary

PUC 2-6

Request:

Based on National Grid's response to PUC 1-12(b), the Commission understands that the forecast of PTF charges included in the 2021 Retail Rate Filing do not account for possible changes to the OATT (relating to the reconstitution of RNL for BTM generation). However, recognizing that the PTF charges National Grid will incur on behalf of customers between April 2021-March 2022 may reflect such changes, please provide your best estimate of PTF charges for the period of April 2021-March 2022 if the OATT changes currently being discussed at ISO-NE take effect. Your response should consider changes in total PTF charges assessed to National Grid that result from changes to both the monthly RNL and the RNS rate itself.

Response:

Due to uncertainty with pending modifications to the definition of RNL, National Grid does not believe that it is possible to provide a meaningfully accurate response to this request. First, no consensus has been reached on changes to the OATT relating to the reconstitution of RNL for BTM generation. In fact, neither the New England Transmission Owners nor ISO-NE has made a final proposal regarding tariff changes. Second, even after such tariff changes are proposed, they will have to be vetted through the NEPOOL stakeholder process and ultimately be presented for acceptance by FERC. Any proposal could be subject to further change in those processes.

In a December meeting with Todd Bianco from the RIPUC, a proposed schedule was communicated with a FERC filing of April 1, 2021 to reflect the definition of RNL with a proposed effective date of June 1, 2021 to coincide with the RNS rate update. As of the middle of March 2021, this schedule is now unknown as discussions are ongoing. Dependent on when such a filing occurs, any changes to RNL may not take effect for quite some time. This analysis is calculating the impact assuming a new definition of RNL does apply for the requested recovery period of April 2021 through March 2022.

With that said, and subject to the caveats below, please see Attachment PUC 2-6 which calculates the estimated impact to Narragansett Electric's ("NECO's") PTF charges billed from ISO-NE. The impact to the April 2021 through March 2022 forecast period results in a hypothetical estimated increase of $3,422,655.

This request asks for "changes in total PTF charges assessed to National Grid that result from changes to both the monthly RNL and the RNS rate itself." Please note that, as explained below,

PUC 2-6, page 2

the RNS rate itself will not change for the period referenced in the request. However, the monthly RNL for the referenced period may change.

ISO-NE PTF Demand Charges are calculated by multiplying the customer’s monthly RNL by the RNS rate in effect for that period. The RNS rate in effect is calculated by dividing the aggregated PTF revenue requirement of all NETO’s by the RNL for the prior year.

The RNS rate in effect for April 2021 through March 2022 will cover two RNS periods. Firstly, April 2021 and May 2021 will be based on the RNS rate effective June 1, 2020. This rate is based on the aggregated forecasted PTF revenue requirement for calendar year 2020 based on actual Calendar Year 2019 FERC Form 1 data and forecasted plant additions divided by the actual 2019 RNL. Secondly, the RNS rate in effect for June 2021 through March 2022 will be based on the RNS rate effective June 1, 2021. This rate will be similarly based on the forecasted aggregated PTF revenue requirement for calendar year 2021 using Calendar Year 2020 FERC Form 1 data and forecasted plant additions divided by the actual 2020 RNL.

Since the RNS rates effective throughout the forecast period of April 2021 through March 2022 are based on RNL from prior calendar years 2019 and 2020, any change to the definition of RNL made after 2020 will not be reflected in the RNS rate applicable to this Data Request. As a result, the RNS rates remain unchanged for the purposes of this calculation. Any change made to the RNL in calendar year 2021 will flow through the RNS rate effective in a future period.

However, since NECO’s ISO-NE PTF demand charges are a function of the RNS rate and its own monthly RNL, NECO’s ISO-NE PTF demand charges are affected by uncertainty with respect to monthly RNL. The calculation performed by the Company to respond to this Data Request attempts to take into account hypothetical changes to NECO’s RNL used to determine it’s PTF Demand Charges. Changes in RNL based upon certain hypothetical assumptions about the reconstitution of BTM generation are reflected in Column 4 to Attachment PUC 2-6. Those hypothetical assumptions include reconstituting net metering and REG projects that have interval meters in place so the needed hourly calculations could occur.

Prepared by or under the supervision of: Timothy Roughan and Michael Artuso

The Narragansett Electric Company
Estimated Changes in PTF Demand Charges
Estimated for the Year 2021 Due to Reconstitution of Regional Network Load

Line #	Period	(1) Annual RNS Rate ($/kW-Yr)	(2) Monthly PTF kW Load	(3) PTF Demand Charge	(4) Reconstituted Load Impact	(5) Revised Monthly PTF kW Load	(6) Revised PTF Demand Charge	(7) Variance PTF Demand Charge
1	April	$ 129.26	804,458	8,665,475	28,757	833,215	8,975,241	309,766
2	May	$ 129.26	891,538	9,603,485	26,356	917,894	9,887,387	283,902
3	June	$ 138.37	1,287,087	14,841,186	35,903	1,322,990	15,255,177	413,991
4	July	$ 138.37	1,645,283	18,971,484	38,972	1,684,255	19,420,864	449,380
5	August	$ 138.37	1,543,475	17,797,553	44,140	1,587,615	18,306,524	508,971
6	September	$ 138.37	1,205,878	13,904,778	39,190	1,245,068	14,356,672	451,894
7	October	$ 138.37	970,360	11,189,059	25,253	995,613	11,480,248	291,189
8	November	$ 138.37	972,162	11,209,838	28,636	1,000,798	11,540,035	330,197
9	December	$ 138.37	1,127,719	13,003,540	4,941	1,132,660	13,060,514	56,974
10	January	$ 138.37	1,061,037	12,234,641	8,008	1,069,045	12,326,980	92,339
11	February	$ 138.37	971,973	11,207,659	16,713	988,686	11,400,373	192,714
12	March	$ 138.37	942,236	10,864,766	3,585	945,821	10,906,104	41,338
13	**Total**		**13,423,206**	**$153,493,464**	**300,454**	**13,723,660**	**$156,916,119**	**$3,422,655**

Notes

Line 1-2: Column (1) = ISO-NE Section II Open Access Transmission Tariff Rates Posted June 2, 2020
Line 3-12: Column (1) = Schedule MVA-4 Line 6
Line 1-12: Column (2) = ISO-NE Monthly Regional Network Load Reports December 2019 to November 2020
Line 1-12: Column (3) = Column (1) x Column (2) / 12
Line 1-12: Column (4) = Internal Records
Line 1-12: Column (5) = Column (2) + Column (4)
Line 1-12: Column (6) = Column (1) x Column (5) / 12
Line 1-12: Column (7) = Column (6) - Column (3)

PUC 2-7

Request:

Referencing National Grid's response to PUC 1-28(b), please clarify whether National Grid separates out FTM PV from BTM PV by using the FTM share of total PV averaged across the past 5 years of historical data, whether it uses the FTM share of total PV at the time of forecast development, or something else.

Response:

The Company separates the FTM PV from the the BTM PV for its retail energy delivery forecasting by using the FTM share of the total PV from the past five-years' connection data. The FTM PV is excluded from the retail energy delivery forecasting.

PUC 2-8

Request:

Please provide an explanation of how the annual CTCs are determined under the terms of the applicable FERC-approved wholesale settlement agreement which provides how the CTCs are determined and provide a copy of the agreement. Please reference the applicable provisions in the explanation.

Response:

The annual CTC rates are determined pursuant to the Settlements of New England Power Company's (NEP) all-requirements contracts with The Narragansett Electric Company approved by FERC in Docket No. ER97-680-000 and the subsequent Settlement and CTC Implementation Agreement Surrounding Issues Related to the Resolution of the USGENNE Bankruptcy Proceeding in Docket No. ER98-6-000; and the Settlements of Montaup Electric Company's (Montaup) all-requirements contracts with Blackstone Valley Electric Company and Newport Power Corporation approved by FERC in Docket No. ER97-2800-000.

The Company has provided Docket No. ER97-680-000 as Attachment PUC-2-8-1, Docket No. ER98-6-000 as Attachment PUC-2-8-2, and Docket No. ER97-2800-000 and its appendices as Attachments PUC-2-8-3 through PUC-2-8-5.

The "NEP Formula for Calculating Contract Termination Charges" to Narragansett Electric Company begins on Attachment PUC-2-8-1, Page 20. The "Montaup Formula for Calculating Contract Termination Charges" to Blackstone Valley Electric Company and Newport Electric Corporation are in Attachments PUC-2-8-4 and PUC-2-8-5, respectively.

Estimated revenue and expense amounts were established as part of the settlements. The annual CTC reconciliation compares those estimates to January through September actuals and October through December estimates, which are then trued-up in the following year. The reconciliation of revenues compares the estimated to actual gigawatt-hour deliveries at the previous year's CTC rate. The revenue excess/shortfall is then combined with Narragansett Electric Company's share of NEP's actual costs compared to estimates. The net of revenue and expense under/overs is collected in a reconciliation account to which a return is applied, and the ending account balance is divided by the following year's estimated gigawatt-hour deliveries to calculate a CTC rate by which to collect the balance from or refund the balance to customers.

Prepared by or under the supervision of: Kathleen M. Hammer

ORIGINAL

ELECTRIC UTILITY INDUSTRY RESTRUCTURING

Offer of Settlement

FILED
OFFICE OF THE SECRETARY
97 MAY 30 PM 1:20
FEDERAL ENERGY
REGULATORY
COMMISSION

May 30, 1997

Submitted to:
Federal Energy Regulatory Commission
FERC Dkt. ER97-680-000

Submitted by:

New England Power
A NEES company

9706140678-1

Explanatory Statement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New England Power Company) Docket No. ER97-680-000

EXPLANATORY STATEMENT

This Explanatory Statement is submitted in support of the Stipulation and Agreement ("Agreement") 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") (each of the foregoing entities being referred to as a "Signatory" to the Agreement).

If accepted by the Commission, the Agreement would specify the conditions for the termination of the wholesale electric requirements contract between NEP and its affiliate, Narragansett. Currently, NEP supplies all of Narragansett's requirements for electricity to supply retail customers in Narragansett's service territory pursuant to a service agreement under NEP's Primary Service for Resale Tariff (NEP's FERC Electric Tariff, Original Volume No. 1, or "Tariff No. 1"). Under Tariff No. 1, either party must give seven years' advance notice before terminating service.

The Agreement provides for the termination of Narragansett's wholesale purchases under its Tariff No. 1 service agreement earlier, in order to accommodate the introduction of retail choice for customers of Narragansett and the introduction of expanded competition in wholesale electric supplies. The Agreement thus implements both the Rhode Island Utility Restructuring Act of 1996 ("Rhode Island URA") and the policies of this Commission, as articulated in Order No. 888 and 888-A, in favor of wholesale competition. The Agreement also marks an important milestone in the restructuring of the electric utility industry in New England; it is a critical step for the introduction of retail choice for electric service in Rhode Island. Because of the structure of the NEES system, of which NEP and Narragansett are subsidiaries, the Agreement presents a unique circumstance, under which the Commission must approve the voluntary termination of wholesale requirements service in order to enable a State-mandated retail competition program to go forward. As such, it implicates important State interests and is consistent with the Commission's policy of "cooperative federalism," under which it strikes an appropriate balance between Federal and State interests.

The principal components of the Agreement, all of which are interdependent, are as follows:

1. The Signatories agree that it is just, reasonable, and consistent with the public interest to terminate the obligations of NEP and Narragansett under their Tariff No. 1 wholesale requirements service agreement in accordance with the provisions of an amendment to that service agreement ("Amendment") which is appended to the Agreement. Major provisions of the Amendment include the following:

   (a) The Amendment allows Narragansett to reduce its purchase of wholesale requirements service from NEP as of July 1, 1997 and terminate its purchase of wholesale requirements service on or after January 1, 1998 upon 90 days' notice to NEP, rather than seven years' notice.

(b) The Amendment requires Narragansett to pay Contract Termination Charges to NEP, commencing with the termination of its requirements purchase obligation, to enable NEP to recover an allocable share of the costs it has incurred to provide requirements service to Tariff No. 1 customers, including Narragansett. These costs, which are specified in a formula included as part of the Amendment, include costs associated with NEP's investments in generating assets, NEP's contractual commitments for purchased power and fuel transportation, deferred costs and other regulatory assets, nuclear post-shutdown costs including decommissioning costs, and employee severance and retraining costs, together with a return on unrecovered costs. The Agreement includes a mechanism for resolving any disputes that may arise in the implementation of the Contract Termination Charge formula.

(c) The Amendment requires NEP to credit against Narragansett's responsibility for Contract Termination Charges a proportionate share of the remaining value of NEP's generating business. Under the Agreement, NEP will be divesting its generating business. Through the residual value credit and the proposed divestiture, Narragansett's allocable share of the remaining value of NEP's generating assets, as determined by the market, will be passed on to Narragansett, rather than being retained by NEP's shareholders.

(d) The Amendment requires NEP to provide wholesale "Standard Offer Service" to Narragansett after the termination of the Tariff No. 1 purchase obligation, at a fixed schedule of prices (subject to adjustment only for a fuel index) to enable Narragansett to meet its obligations to provide continued service to its retail customers who do not immediately turn to the market for retail power supplies. Although NEP is obligated to supply wholesale Standard Offer Service to Narragansett, Narragansett is not obligated to purchase that wholesale power from NEP after the date when retail customers in Massachusetts are allowed to choose their suppliers. Rather, the Agreement and the Amendment recognize that Narragansett will afford other suppliers the opportunity to bid to supply the power it needs to meet its retail Standard Offer obligations after the Massachusetts retail access date. In this manner, the Agreement provides enhanced opportunities for wholesale competition in conjunction with the introduction of retail competition and, through NEP's obligation to supply wholesale power at a fixed stream of prices, provides a high level of assurance that all Narragansett customers will have an opportunity to benefit from the introduction of competition at wholesale and at retail.

(e) Pending the termination of NEP's Tariff No. 1 wholesale requirements service to Narragansett, current base rates for that service are frozen until the Contract Termination Date.

(f) NEP commits to provide unbundled network transmission service to Narragansett after the termination of bundled requirements service in accordance with the Amendment.

2. The Agreement also reflects NEP's agreement to divest its generation business. NEP has committed to divest its fossil-fuel and hydroelectric generation units, as well as its investments in oil and gas properties, its contractual entitlements to purchase power from third parties and for natural gas pipeline capacity, and generating units owned by affiliates that are controlled and paid for by NEP pursuant to the integrated facilities provisions of Tariff No. 1. NEP has also agreed to attempt to divest its minority interests in certain nuclear generating units. A proportionate share of the net proceeds received by NEP through the divestiture will be credited against Narragansett's obligation to pay Contract Termination Charges. NEP commits to file a plan to implement divestiture with the Commission by October 1, 1997 and to complete divestiture by six months after the later of the introduction of retail access in Massachusetts or the receipt of all necessary governmental approvals. The Commission's acceptance or approval of the Agreement is not intended to constitute any approvals required for the divestiture under section 203 or, with respect to NEP's hydroelectric facilities, Part I of the Federal Power Act. Rather, the Agreement acknowledges that NEP will submit any necessary applications to the Commission at a later date.

(a) The Agreement provides that if NEP retains the obligation to pay post-shutdown, decommissioning, or site restoration costs for its interests in nuclear generating plants as part of the disposition of those interests, NEP will be entitled to recover a proportionate share of those costs from

Narragansett in the Contract Termination Charges. In the event NEP is unable to dispose of its interests in nuclear generating plants, NEP will be entitled to recover 80 percent of the reasonable going forward costs of operating the plants through the Contract Termination Charges and will credit 80 percent of the revenues from the kilowatthour sales from its interests in the plants to the calculation of the Contract Termination Charges. NEP also agrees to present a proposed performance standard applicable to its nuclear plant interests and to support adoption at those plants of a detailed procedure to be implemented in the event it is decided to shut down any of those plants prematurely.

(b) The Agreement provides that NEP may recover in Contract Termination Charges to Narragansett a proportionate share of the payments to power suppliers and other costs associated with buying out of or buying down purchased power contracts. In the event NEP is unable to dispose of its rights under those contracts, the Agreement contemplates that NEP will sell the power purchased under those contracts. Both the contract payments and the revenues received from the sale of that power in the market will be reflected in the Contract Termination Charges. NEP may, however, use its rights under those contracts to fulfill its minimum obligations to supply wholesale Standard Offer Service to Narragansett.

3. The Agreement requires NEP to reduce emissions of NO_x and SO_2 from certain generating units by the amounts and on the schedule specified in an attachment to the

Agreement. This requirement will also apply to the party or parties that acquire those generating units upon NEP's divestiture of them.

4. The Agreement also reflects the Signatories' agreement on the following issues:

(a) The Signatories agree that market pricing is appropriate for sales at wholesale from NEP's generation.

(b) The Signatories agree to the appropriateness of the designation of NEP's generating units as eligible facilities under section 32 of the Public Utility Holding Company Act.

(c) The Signatories agree that all of the facilities of NEP and Narragansett used for the delivery of electricity to retail customers, except for those facilities that are financially supported by NEP pursuant to the integrated facilities provision of NEP's Tariff No. 1, are appropriately classified as distribution facilities subject to the ratemaking jurisdiction of the Rhode Island Commission.

The Agreement specifies that the Commission's acceptance or approval of the Signatories' agreements on the above issues is not a condition of the Commission's acceptance of the Agreement in resolution of this proceeding.

5. The Agreement recognizes that NEP is making substantial and irreversible commitments, including the divestiture of its generating business and the assignment of Narragansett's share of the residual value of its generating assets for the benefit of Narragansett and its customers, primarily in consideration for an entitlement to the recovery of Contract Termination Charges from Narragansett, determined in accordance with the Amendment, over an

extended period of time. To give effect to NEP's reliance on the bargain reflected in the Agreement and the Amendment, the Signatories seek the Commission's assurance that it will, to the fullest extent permissible under the Federal Power Act, give effect to NEP's right to charge and recover Contract Termination Charges from Narragansett in accordance with the Amendment. The Agreement specifically precludes application to the Commission for changes to the Contract Termination Charge formula, under either section 205 or section 206 of the Federal Power Act, absent NEP's agreement (section 3.6) and calls upon the Commission to refrain from revisiting the issue of the justness and reasonableness of the Contract Termination Charges or from limiting NEP's right to recover in full the Contract Termination Charges contemplated by the Agreement (section 6.1.4).

NEP recognizes that the Commission's responsibility to order changes in jurisdictional rates that are contrary to the public interest cannot be precluded by a settlement agreement. See El Paso Electric Co., 43 FERC ¶ 61,201 (1988). The Signatories have concluded that, taken as whole, the provisions of the Agreement, including NEP's recovery of the Contract Termination Charges in full, are just, reasonable, and consistent with the public interest. The Signatories have also recognized that the Agreement goes beyond the resolution of a single wholesale rate proceeding. Rather, it provides the terms for the fundamental restructuring of the contractual relationship between NEP and Narragansett and commits NEP to divest its generating business. In light of the gravity and the irreversible nature of the mutual commitments reflected in the Agreement, the Signatories seek to assure the continued vitality of those commitments to the greatest extent possible consistent with the Commission's exercise of its statutory authority. As other regulatory agencies have done when they have approved similarly long-lived settlements, see Pacific Gas & Electric Co., 99 P.U.R. 4th 141 (Cal. Publ. Util. Com'n 1988), the Commission should indicate that it .recognizes the unusual nature of the commitments in the Agreement and will not disturb them absent an unequivocal showing that the public interest cannot be served in any other way.

6. The Agreement does not affect Tariff No. 1 customers other than Narragansett. The Amendment modifies the Tariff No. 1 service agreement between NEP and Narragansett, not Tariff No. 1 itself. Indeed, the Agreement modifies Tariff No. 1 only to add a statement to ensure that the termination of Narragansett's Tariff No. 1 service will not cause NEP's fuel charges to other Tariff No. 1 customers to increase. NEP will continue to provide wholesale requirements service under Tariff No. 1 to current customers who choose not to terminate that service.

Respectfully submitted,

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Stipulation and Agreement

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 Resolution of Disputes Associated with the Implementation of the Contract Termination Charge.

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 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 <u>Amendment to Fuel Clause</u>

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

[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 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,

New England Power Company
Settlement Agreement

FERC Dkt. ER97-680-000

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

Dated: May 29, 1997

Rhode Island Division of Public Utilities and Carriers

Attachment 1

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.

ADJUSTMENT TO DEMAND RELATED EXPENSE	=	(Average Demand Charge Including Retail Access Load	-	Average Demand Charge Excluding Retail Access Load)	x	Total kW Purchases Excluding Retail Access Load
ADJUSTMENT TO ON-PEAK ENERGY EXPENSE	=	(Avg Peak Energy Charge Including Retail Access Load	-	Avg Peak Energy Charge Excluding Retail Access Load)	x	Total Peak kWh Purchases Excluding Retail Access Load
ADJUSTMENT TO OFF-PEAK ENERGY EXPENSE	=	(Avg Off-Pk Energy Charge Including Retail Access Load	-	Avg OffPk Energy Charge Excluding Retail Access Load)	x	Total Off-Pk kWh Purchases Excluding Retail Access Load

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

[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

Its President

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Appendix 1

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 a twelve and one-half year period commencing on July 1, 1997 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 NEP generation-related investments as of June 30, 1997,[1/] excluding any capital additions made after December 31, 1995:

(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, 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 Maine Yankee and Vermont Yankee Units;
(vi) NEP's ownership share of Millstone Unit 3;
(vii) NEP's ownership share of Seabrook Unit 1;

[1/]The figures shown on Schedule 1, Page 4, Column (7) are estimates and will be updated for actual balances as of June 30, 1997. Changes, if any, shall be reconciled at the Divestiture Date.

(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 nonutility 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 June 30, 1997[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;
(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.

1.1.2 Revenues sufficient to provide an overall pre-tax return of 11.01 percent based on a combined state and federal income tax rate of 39.225 percent, and NEP's 1995 year-end

[2/] The figures shown on Schedule 1, Page 5, Column (2) are estimates and will be updated for actual balances as of June 30, 1997. In addition, the balance in the W-95 Settlement Adjustment Account will be updated again at the Contract Termination Date. Changes, if any, shall be reconciled at the Divestiture Date.

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 divestiture of NEP's non-nuclear generating facilities ("Divestiture Date")[3/], and 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,[4/] multiplied by the average of the beginning and ending balances in each calendar year beginning in 1997 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 under 1.1.1(b)(vii) and (xiii), less

[3/]If NEP 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.

[4/]The difference between the 11.01 percent and 12.56 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, and the difference between the 11.01 and 12.56 percent returns that occurs after the Divestiture Date shall be included in the Reconciliation Account. The 11.01 percent and 12.56 percent returns 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). Notwithstanding the above, an equity return of 9.4 percent will be applied to NEP's equity investment in the Ocean State Power facility for purposes of estimating Contract Termination Charges under the Agreement and such equity return shall increase to 11 percent following divestiture.

(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
(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 a twelve and one-half year period commencing on July 1, 1997 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[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 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. Following the Divestiture Date,[6/] 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

[5/] 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.

[6/] If NEP sells its non-nuclear generating facilities in more than one transaction, the FAS 106 transition obligation and adjustments shall be allocated based on the ratio of direct payroll costs at each generating facility sold to total direct payroll costs at all of NEP's non-fossil generating facilities.

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 period between July 1, 1997 and the Contract Termination Date, NEP 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 W-95(S) 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 Narragansett's 22.4 percent allocated share and further multiplied by the percentage of kilowatthours delivered to customers who continue to buy their electricity from Narragansett to the total number of kilowatthours delivered by Narragansett to all customers in Narragansett's Service Territory. An exhibit showing the difference between depreciation and amortization under W-95(S) 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, NEP shall reconcile the balances 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.[7] 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 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 for Narragansett's 22.4 percent allocated share of (iii) the FAS 109 regulatory asset; and (iv)

[7] 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.

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) 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) NEP 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 ER97-680-000 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,[8] the cost of which is included in the Contract Termination Charge, NEP shall implement a Residual Value Credit as a direct offset to the Contract Termination

[8] Proceeds, if any, from NEP's future leases of nuclear entitlements will also be flowed through the Residual Value Credit.

Charges authorized under this Amendment. The Residual Value Credit to Narragansett shall be calculated as follows:

(i) Narragansett's 22.4 percent allocated share of Total Proceeds[9/] equal to the sale price and other consideration received by NEP excluding $85 million[10/] which purchasers will be required to pay 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[11/] 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 transmission revenues and Contract Termination Charge revenues,

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[9/]As part of the terms of the Divestiture, NEP shall require 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 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. NEP 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..

[10/]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.

[11/]If NEP sells its non-nuclear generating facilities in more than one transaction, the revenues lost shall be allocated based on the kilowatthours generated by the unit sold to total kilowatthours generated from NEP's non-nuclear generating facilities during the period from July 1, 1997 to the Divestiture Date.

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,[12/] 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

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[12/]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, at the time of the calculation of the Residual Value Credit, 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.

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 the sale of assets, whose costs have been included in the Contract Termination Charge, occurs after December 31, 2009, NEP shall implement a Residual Value Credit following that date to amortize the proceeds with the return specified above, over no more than five years.

(e) Effective with refinancings, repurchases, and retirements of securities on and after March 20, 1997, NEP shall, for all purposes associated with the implementation of the Contract Termination Charge or the Residual Value Credit, flow through the Residual Value Credit 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(a) 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.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust NEP's Base Contract Termination Charges to Narragansett on January 1, 2001. Thus, effective January 1, 2001, NEP shall return or collect Narragansett's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Narragansett. Thereafter, the balance including the accumulated return in the Reconciliation Account at the end of a year shall be used to adjust NEP'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. Any Reconciliation Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract Termination Charge to increase or decrease by more than 0.2 cent per kilowatthour shall be amortized with a return over the three years following January 1, 2001.

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 and Connecticut 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) Above Market Payments to Power Suppliers will be (i) all payments by NEP 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 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 all reasonable payments agreed to by NEP after April 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. If the Contract Termination Date has not yet occurred at the time that an Economic Buyout Payment is made, the schedule of recovery set forth in the prior two sentences shall be applied to NEP's Tariff No. 1 fuel clause to Narragansett so that NEP fully recovers Narragansett's allocated share of the Economic Buyout Payment from Narragansett.

(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) Ocean State Power
(2) Maine Yankee
(3) Millstone 3
(4) 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.

(c) Above Market Fuel Transportation as shown in Schedule 1, Page 11, will be the sum of NEP's continuing long-term payment obligations associated with (i) Capacity Payments to Interstate Natural Gas Pipelines, less the market value of that capacity, and (ii) coal ship obligations less the market value associated with those obligations (see Schedule 1, page 11).

(i) Capacity Payments to Interstate Natural Gas Pipelines will be all capacity payments for Interstate Pipeline Capacity Contracts in effect as of December 31, 1995. They include:

(1) NOVA
(2) TCPL
(3) Iroquois
(4) Tennessee
(5) Algonquin
(6) ANR
(7) Columbia
(8) Distrigas
(9) Providence Gas
(10) Brayton Point Lateral

The Market Value of Capacity Payments to Interstate 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 NEP's contractual entitlements to the pipeline capacity are assigned to a nonaffiliate, the Market Value of Capacity Payments to Interstate Natural Gas Pipelines shall be deemed to equal the amounts shown on page 11 of Schedule 1, which are 50 percent of such capacity payments.

(ii) Coal Ship Obligations will be all payments by NEP under its charter with the Energy Enterprise until the contract is otherwise terminated or assigned. The market value of these Coal Ship Obligations will equal the actual proceeds associated with the assignment or termination of the charter with the Energy Enterprise, and are assumed to be zero for the purpose of calculating the Base Contract Termination Charges and the estimate included in the Reconciliation Account. See Schedule 1, page 11.

(d) Transmission wheeling charges as shown in Schedule 1, Page 3, associated with the transmission of electricity from NEP's entitlements in Connecticut Yankee, Maine Yankee, Millstone Unit 3, Wyman Unit 4, Vermont Yankee, and NEP's purchase from a slice of Northeast Utilities system, 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,[13/] associated with NEP's nuclear units or entitlements that are not otherwise recovered in contract termination charges less 80 percent

[13/] 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.

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 nonperformance of $1 million. Such sales, if any, shall only be made in the wholesale market to nonaffiliates, provided, however, 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. 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).

Schedules 1-5

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

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	Base Contract Termination Charge
					$ in Millions	cents/kwh	$ in Millions	cents/kwh	$ in Millions	cents/kwh
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	1997	4,758	50%	2,379	$30	1.26	$37	1.54	$67	2.80
2	1998	4,879	100%	4,879	66	1.35	71	1.45	137	2.80
3	1999	5,013	100%	5,013	73	1.45	68	1.35	140	2.80
4	2000	5,165	100%	5,165	78	1.52	66	1.28	145	2.80
5	2001	5,183	100%	5,183	56	1.08	73	1.40	129	2.48
6	2002	5,232	100%	5,232	53	1.02	69	1.32	122	2.33
7	2003	5,288	100%	5,288	51	0.96	66	1.25	117	2.20
8	2004	5,356	100%	5,356	48	0.90	65	1.21	113	2.11
9	2005	5,428	100%	5,428	45	0.84	65	1.21	111	2.04
10	2006	5,496	100%	5,496	43	0.78	64	1.17	107	1.96
11	2007	5,562	100%	5,562	40	0.72	62	1.12	102	1.84
12	2008	5,628	100%	5,628	37	0.67	61	1.09	99	1.76
13	2009	5,695	100%	5,695	35	0.61	53	0.93	88	1.55
14	2010	5,783	100%	5,783			49	0.84	49	0.84
15	2011	5,864	100%	5,864			36	0.61	36	0.61
16	2012	5,946	100%	5,946			30	0.50	30	0.50
17	2013	6,029	100%	6,029			30	0.49	30	0.49
18	2014	6,114	100%	6,114			28	0.46	28	0.46
19	2015	6,199	100%	6,199			27	0.44	27	0.44
20	2016	6,286	100%	6,286			23	0.37	23	0.37
21	2017	6,374	100%	6,374			23	0.36	23	0.36
22	2018	6,463	100%	6,463			17	0.26	17	0.26
23	2019	6,554	100%	6,554			17	0.26	17	0.26
24	2020	6,646	100%	6,646			12	0.17	12	0.17
25	2021	6,739	100%	6,739			12	0.17	12	0.17
26	2022	6,833	100%	6,833			12	0.17	12	0.17
27	2023	6,929	100%	6,929			12	0.17	12	0.17
28	2024	7,026	100%	7,026			12	0.17	12	0.17
29	2025	7,124	100%	7,124			12	0.17	12	0.17
30	2026	7,224	100%	7,224			7	0.10	7	0.10
31	2027	7,325	100%	7,325			6	0.08	6.0	0.08
32	2028	7,427	100%	7,427			6	0.08	6.0	0.08
33	2029	7,531	100%	7,531			6	0.08	5.9	0.08

(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 Page 2, Column (7).
(6) Column (5)/Column (4) x 100.
(7) See Page 3, Column (18).
(8) Column (7)/Column (4) x 100.
(9) Column (5) + Column (7).
(10) Column (9) / Column (4) x 100.

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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)	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	1997	$18	$11	$1	$30	$0	$30
2	1998	34	30	2	66	0	66
3	1999	30	40	2	73	0	73
4	2000	27	50	2	78	0	78
5	2001	23	31	2	56	0	56
6	2002	21	31	2	53	0	53
7	2003	18	31	2	51	0	51
8	2004	16	31	2	48	0	48
9	2005	13	31	2	45	0	45
10	2006	11	31	2	43	0	43
11	2007	8	31	1	40	0	40
12	2008	6	31	1	37	0	37
13	2009	3	31	1	35	0	35
14	2010						
15	2011						
16	2012						
17	2013						
18	2014						
19	2015						
20	2016						
21	2017						
22	2018						
23	2019						
24	2020						
25	2021						
26	2022						
27	2023						
28	2024						
29	2025						

Column Notes:

Each Column represents 22.4% of the same Column number on Page 12.

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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	1997	$5	$42	$15	$26	$0	($1)	($1)	($0)	$5	$0	$0	$0	$0	$0	$37	NA	$37
2	1998	10	83	32	51	0	(3)	(2)	(1)	10	1	0	0	0	0	71	NA	71
3	1999	9	83	34	50	0	(3)	(2)	(1)	10	1	0	0	0	0	68	NA	68
4	2000	8	84	34	50	0	(3)	(2)	(1)	10	1	0	0	0	0	66	NA	66
5	2001	11	86	34	52	0	(2)	(1)	(1)	10	1	0	0	0	0	73	0	73
6	2002	11	85	37	49	0	(2)	(1)	(1)	10	0	0	0	0	0	69	0	69
7	2003	11	80	34	46	0	(2)	(1)	(1)	10	0	0	0	0	0	66	0	66
8	2004	11	81	35	45	0	(2)	(1)	(1)	9	0	0	0	0	0	65	0	65
9	2005	12	80	35	45	0	(2)	(1)	(1)	9	0	0	0	0	0	65	0	65
10	2006	12	80	35	44	0	(2)	(1)	(1)	9	0	0	0	0	0	64	0	64
11	2007	11	81	37	44	0	(2)	(1)	(1)	8	0	0	0	0	0	62	0	62
12	2008	9	84	39	45	0	(2)	(1)	(1)	8	0	0	0	0	0	61	0	61
13	2009	8	73	35	38	0	(2)	(1)	(1)	7	0	0	0	0	0	53	0	53
14	2010	9	66	33	33	0	(2)	(1)	(1)	7	0	0	0	0	0	49	0	49
15	2011	9	49	25	23	0	0	0	0	4	0	0	0	0	0	36	0	36
16	2012	8	27	9	19	0	0	0	0	3	0	0	0	0	0	30	0	30
17	2013	7	28	9	19	0	0	0	0	3	0	0	0	0	0	30	0	30
18	2014	7	28	9	19	0	0	0	0	2	0	0	0	0	0	28	0	28
19	2015	8	29	9	19	0	0	0	0	0	0	0	0	0	0	27	0	27
20	2016	8	22	7	15	0	0	0	0	0	0	0	0	0	0	23	0	23
21	2017	8	22	7	15	0	0	0	0	0	0	0	0	0	0	23	0	23
22	2018	8	12	3	9	0	0	0	0	0	0	0	0	0	0	17	0	17
23	2019	8	12	3	9	0	0	0	0	0	0	0	0	0	0	17	0	17
24	2020	9	3	0	3	0	0	0	0	0	0	0	0	0	0	12	0	12
25	2021	9	3	0	3	0	0	0	0	0	0	0	0	0	0	12	0	12
26	2022	9	3	0	3	0	0	0	0	0	0	0	0	0	0	12	0	12
27	2023	9	3	0	3	0	0	0	0	0	0	0	0	0	0	12	0	12
28	2024	9	3	0.1	3	0	0	0	0	0	0	0	0	0	0	12	0	12
29	2025	9	3	0.1	3	0	0	0	0	0	0	0	0	0	0	12	0	12
30	2026	7	0.1	0.1	0.0	0	0	0	0	0	0	0	0	0	0	7	0	7
31	2027	6	0.1	0.1	0.0	0	0	0	0	0	0	0	0	0	0	6	0	6
32	2028	6	0.1	0.1	0.0	0	0	0	0	0	0	0	0	0	0	6	0	6
33	2029	6	0.0	0.0	0.0	0	0	0	0	0	0	0	0	0	0	6	0	6

Column Notes:

Columns (2) through (16) represent 22.4% of the same Column number on Page 15.

(17) See Schedule 2, Page 3, Column (7) x -1
(18) Column (16) + Column (17).

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New England Power Company's Generation Facilities
Net Capability and Unrecovered Costs
as of December 31, 1995

Source	Location	Year(s) Placed In-Service	Energy Source	Net Capability (MW)	$ Millions 1995		$ Millions 06/30/97		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		$384		$34.0	$34.0	(c)
Manchester St. Station	Prov., R.I.	1995	Oil-Gas	513	468	(a)	441	(a)	18.2	18.2	(d)
Hydroelectric Units											
Conventional	Mass., N.H. & Vt.	1909-1987	Water	577	170		165		3.3	3.3	
Pumped Storage Bear Swamp	Rowe, Mass.	1974	Water	589	73		71		1.4	1.4	
Nuclear Units											
Yankees and Vt.	Maine & Vt.	1968-1972	Nuclear	341	75	(b)	68	(b)	5.1	5.1	(e)
Millstone 3	Waterford, Conn.	1986	Nuclear	140	391	(b)	360	(b)	30.0	44.9	(f)
Seabrook 1	Seabrook, N.H.	1990	Nuclear	115	59	(b)	42	(b)	1.8	1.9	
Step-Up Transformers at Generation Facilities (Not Included in Transmission Rates)					8		8		0.3	0.3	
General Plant Allocated to Generation					10		9		0.6	0.6	
Generation Related Property Held For Future Use and Non-Utility Property					10		10		0.0	0.0	
Nantucket Generating Units (Not included in Transmission Rates)					9		8		0.6	0.6	
Total				4,666	$1,709		$1,565		$96.3	$110.2	

(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. Maine Yankee license expires 2008 and 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.

New England Power Company Generation Related

Regulatory Asset Balances

$ in Millions

	Balance as of December 31, 1995	Balance as of June 30, 1997	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	$26	$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	54	2.3	2.3	Settlement Agreement (1)
NEEI	226	158	18.0	21.2	Settlement Agreement (2)
FAS 106 Deferral	13	5	11.0	0.0	FERC Ratemaking Policy
Power Contract Buyouts	24	18	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	2	0.2	0.2	FERC Ratemaking Policy
W-95S Adjustment Account	2.2	(1.5)	0.3	0.0	Settlement Agreement (3)
Unamortized ITC	(47)	(45)	(1.2)	(1.2)	FERC Ratemaking Policy
Total Regulatory Assets	$360	$250	$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)

New England Power Company

FAS 106 Transition Obligation Regulatory Asset

$ in Millions

Unrecovered Balance as of 6/30/97	$67.9
Actuarial Discount Rate	7.25%
Amortization (straightline)	12.5 years

	Amortization (1)	Interest (2)	Total Expense (3)	Unamortized Balance (4)
				67.9
1997	2.7	2.4	5.1	65.2
1998	5.4	4.5	10.0	59.7
1999	5.4	4.1	9.6	54.3
2000	5.4	3.7	9.2	48.9
2001	5.4	3.3	8.8	43.4
2002	5.4	3.0	8.4	38.0
2003	5.4	2.6	8.0	32.6
2004	5.4	2.2	7.6	27.2
2005	5.4	1.8	7.2	21.7
2006	5.4	1.4	6.8	16.3
2007	5.4	1.0	6.4	10.9
2008	5.4	0.6	6.0	5.4
2009	5.4	0.2	5.6	(0.0)
	67.9			

Column Notes:

(1) Column (4) 6/30/1997 balance/12.5.
(2) (Prior year Column (4) + Current year Column (4))/2 x .0725
(3) Column (1) + Column (2)
(4) Prior year Column (4) - Column (1)

New England Power Company Share of

Total Nuclear Post-Shutdown Costs

$ in Millions

	Millstone 3 (1)	Seabrook 1 (2)	Vermont Yankee (3)	Maine Yankee (4)	Total (5)
1997	0	0	0	0	0
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	7	6	7	7	26
2002	7	6	7	7	26
2003	7	6	7	7	26
2004	7	6	7	7	26
2005	7	6	7	7	26
2006	7	6	7	7	26
2007	7	6	7	7	26
2008	7	6	7	7	26
2009	7	6	7	7	26
2010	7	6	7	7	26
2011	7	6	7	7	26
2012	7	6	7	7	26
2013	7	6	7	7	26
2014	7	6	7	7	26
2015	7	6	7	7	26
2016	7	6	7	7	26
2017	7	6	7	7	26
2018	7	6	7	7	26
2019	7	6	7	7	26
2020	7	6	7	7	26
2021	7	6	7	7	26
2022	7	6	7	7	26
2023	7	6	7	7	26
2024	7	6	7	7	26
2025	7	6	7	7	26
2026	7	6	7	7	26
2027	7	6	7	7	26
2028	7	6	7	7	26
2029	7	6	7	7	26

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Schedule 1
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New England Power Company Share of

Total Annual Decommissioning Cost

$ in Millions

	Millstone 3 (1)	Seabrook 1 (2)	Connecticut Yankee (3)	Vermont Yankee (4)	Maine Yankee (5)	Yankee Atomic (6)	Total Nuclear Decommissioning (7)
1997	1	1	24	2	3	15	47
1998	1	1	24	2	3	14	46
1999	1	1	17	2	3	15	40
2000	2	2	16	3	3	8	34
2001	2	2	15	3	3	0	25
2002	2	2	13	3	3	0	24
2003	2	2	13	4	3	0	23
2004	2	2	13	4	4	0	24
2005	3	2	13	4	4	0	26
2006	3	2	13	4	4	0	26
2007	3	2	8	5	4	0	21
2008	3	2	0	5	3	0	13
2009	3	2	0	5	0	0	10
2010	4	3	0	5	0	0	12
2011	4	3	0	6	0	0	13
2012	4	3	0	2	0	0	8
2013	4	3	0	0	0	0	7
2014	4	3	0	0	0	0	7
2015	5	4	0	0	0	0	9
2016	5	4	0	0	0	0	9
2017	5	4	0	0	0	0	9
2018	5	4	0	0	0	0	9
2019	5	4	0	0	0	0	9
2020	7	6	0	0	0	0	13
2021	7	6	0	0	0	0	13
2022	7	6	0	0	0	0	13
2023	7	6	0	0	0	0	13
2024	7	6	0	0	0	0	13
2025	8	7	0	0	0	0	15
2026	0	5	0	0	0	0	5

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Power Contract Obligations
Annual Obligations in Millions of Dollars

	OSP	Canal	NU Slice	Lawrence Hydro	Mascoma Hydro	Pontook Hydro	Northeast Landfill	Turnkey Rochester NH	Ogden Haverhill	RESCO Saugus	RESCO N. Andover	Signal-Milbury	Waschusett Hydro MWRA	RFA Lawrence	Altresco	Clark University	Milford Power	Pawtucket	Hydro-Quebec DC hase 1 & 2	TOTAL
1997	98	30	8	5	0	5	6	1	28	19	5	29	1	0	53	0	33	34	17	372
1998	95	30	7	5	0	5	6	1	29	19	5	30	1	0	53	0	33	33	17	370
1999	96	31	0	5	0	5	7	1	29	19	6	30	1	0	54	0	36	34	16	371
2000	93	34	0	5	0	5	7	1	30	20	7	31	1	0	54	0	37	35	16	375
2001	95	30	0	4	0	5	7	1	31	21	9	33	1	0	53	0	41	35	16	382
2002	97	25	0	4	0	4	7	1	32	21	7	33	1	0	55	0	42	35	16	381
2003	96	0	0	4	0	4	7	2	32	22	8	34	1	0	56	0	43	36	15	358
2004	93	0	0	4	0	4	7	2	33	22	8	34	1	0	56	0	44	36	15	359
2005	95	0	0	4	0	4	7	2	33	22	3	35	1	0	56	0	45	37	14	359
2006	92	0	0	4	0	4	7	2	34	23	0	35	1		56	0	46	37	14	355
2007	94	0	0	4	0	4	8	2	34	23	0	36	1		58	0	47	37	13	361
2008	99	0	0	4	0	4	8	2	35	24	0	37	1		59	0	51	38	13	374
2009	99	0	0	3	0	4	8	0	36	24	0	37	1		60	0	2	38	13	327
2010	93	0	0	3	0	5	1	0	36	24	0	38	1		41	0	0	39	13	294
2011	91	0	0	3	0	5	0	0	37	25	0	39	1			0	0	3	13	217
2012	0	0	0	0	0	5	0	0	38	25	0	39	1			0	0		13	122
2013	0	0	0	0	0	5	0	0	38	26	0	40	1			0	0		13	123
2014	0	0	0	0	0	5	0	0	39	26	0	41	1			0	0		13	126
2015	0	0	0	0	0	5	0	0	40	26	0	42	1			0			14	128
2016	0	0	0	0	0	5	0	0	40	0	0	42	0			0			11	99
2017	0	0	0	0	0	0	0	0	41	0	0	43	0			0			11	96
2018	0	0	0	0	0	0	0	0	42	0	0	0	0			0			12	54
2019	0	0	0	0	0	0	0	0	43	0	0	0	0			0			12	55
2020	0	0	0	0	0	0	0	0	0	0	0	0	0			0			12	13
2021	0	0	0	0	0	0	0	0	0	0	0	0	0			0			12	13
2022	0	0	0	0	0	0	0	0	0	0	0	0	0			0			13	13
2023	0	0	0	0	0	0	0	0	0	0	0	0	0			0			13	13
2024	0	0	0	0	0	0	0	0	0	0	0	0	0			0			13	14
2025	0	0	0	0	0	0	0	0	0	0	0	0	0			0			14	14
2026	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
2028	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

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Power Contract Obligations
Annual Obligations in GWH

	OSP	Canal	NU Slice	Lawrence Hydro	Mascoma Hydro	Pontook Hydro	Northeast Landfill	Turnkey Rochester NH	Ogden Haverhill	RESCO Saugus	RESCO N. Andover	Signal-Milbury	Waachusett Hydro MWRA	RFA Lawrence	Altresco	Clark University	Milford Power	Pawtucket	TOTAL
1997	1,879	850	94	70	4	64	100	24	306	226	210	321	13	0	800	0	444	453	5,857
1998	1,879	782	95	70	4	64	100	24	306	226	210	321	13	0	762	0	424	425	5,705
1999	1,879	774		70	4	64	100	24	306	226	210	321	13	0	790	0	464	453	5,699
2000	1,879	896		70	4	64	100	24	307	227	211	322	13	0	737	0	438	454	5,746
2001	1,879	736		70	4	64	100	24	317	242	240	333	13	0	716	0	531	497	5,766
2002	1,879	613		70	4	64	100	24	317	242	240	333	13	0	800	0	504	469	5,672
2003	1,879			70	4	64	100	24	317	242	240	333	13	0	800	0	538	497	5,121
2004	1,879			70	4	64	100	24	318	243	241	334	13	0	802	0	546	504	5,142
2005	1,879			70	4	64	100	24	317	242	100	333	13	0	744	0	558	509	4,956
2006	1,879			70	4	64	100	24	317	242		333	13		716	0	572	509	4,841
2007	1,879			70	4	64	100	24	317	242		333	13		800	0	545	475	4,865
2008	1,879			70	4	64	100	24	318	243		334	13		802	0	607	510	4,967
2009	1,879			70	4	64	100	4	317	242		333	13		800	0	25	509	4,359
2010	1,879			70	4	64	8		317	242		333	13		497	0		503	3,931
2011	1,879			70	4	64			317	242		333	13			0		42	2,964
2012					4	64			318	243		334	13			0			975
2013					4	64			317	242		333	13			0			973
2014					4	64			317	242		333	13			0			973
2015					4	64			317	242		333	10			0			969
2016					4	64			317			333				0			718
2017					4	5			317			333				0			659
2018					4				317							0			321
2019					4				317							0			321
2020					4											0			4
2021					4											0			4
2022					4											0			4
2023					4											0			4
2024					4											0			4
2025					4											0			4
2026					4														4
2027					4														4
2028					4														4
2029					0														0

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New England Power Company

Annual Utility Unit Sales Power Contracts

$ in Millions

	OSP (1)	Maine Yankee (2)	Millstone 3 (3)	Millstone3/ Seabrook 1 (4)	TOTAL (5)
1997	5	0	1	5	**12**
1998	8	1	1	5	**15**
1999	8	0	1	6	**15**
2000	8	1	1	6	**15**
2001	8	1	1		**10**
2002	8	1	1		**10**
2003	8	1	1		**10**
2004	8	1	1		**9**
2005	8	1	1		**9**
2006	8	1	1		**9**
2007	8				**8**
2008	8				**8**
2009	8				**8**
2010	7				**7**

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New England Power Company
Fixed Costs of Gas Transportation
Contractual Commitments

Annual Expenses

$ in Millions

	Total Pipeline Demand Charge Obligation (1)	Assumed Market Value (2)	Excess Over Market (3)	Total Energy Enterprise Minimum Payments (4)	Assumed Market Value (5)	Excess Over Market (6)	Total Above Market Fuel Transportation Costs (7)
1997	$62	$31	$31	$15	$0	$15	$46
1998	61	31	31	13	0	13	44
1999	60	30	30	13	0	13	43
2000	60	30	30	13	0	13	43
2001	59	29	29	14	0	14	43
2002	58	29	29	14	0	14	43
2003	57	28	28	15	0	15	43
2004	56	28	28	13	0	13	41
2005	55	28	28	14	0	14	41
2006	54	27	27	14	0	14	41
2007	41	20	20	14	0	14	35
2008	40	20	20	15	0	15	35
2009	35	18	18	15	0	15	33
2010	35	17	17	16	0	16	33
2011	34	17	17	1	0	1	18
2012	30	15	15	0	0	0	15
2013	29	15	15	0	0	0	15
2014	16	8	8	0	0	0	8

Columns Notes:

(2) Assumes 50% of obligation is recoverable through the market. Upon actual market valuation, this component will be adjusted for actual market value realized.
(3) Column (1) - Column (2).
(5) Assumes 0% of obligation is recoverable through the market. Upon actual market valuation, this component will be adjusted for actual market value realized.
(6) Column (4) - Column (5).
(7) Column (3) + Column (6).

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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)	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	1997	$80	$49	$5	$134	$0	$134
2	1998	150	135	10	295	0	295
3	1999	135	180	10	325	0	325
4	2000	118	222	9	349	0	349
5	2001	104	137	9	249	0	249
6	2002	92	137	8	237	0	237
7	2003	81	137	8	226	0	226
8	2004	70	137	8	214	0	214
9	2005	59	137	7	202	0	202
10	2006	47	137	7	191	0	191
11	2007	36	137	6	179	0	179
12	2008	25	137	6	167	0	167
13	2009	13	137	6	156	0	156
14	2010						
15	2011						
16	2012						
17	2013						
18	2014						
19	2015						
20	2016						
21	2017						
22	2018						
23	2019						
24	2020						
25	2021						
26	2022						
27	2023						
28	2024						
29	2025						

Column Notes:
(2) See Page 14, Column (9).
(3) For years 1997-2000 Column (3) = [Page 1, Column (10) x Page 1, Column (4)]/100/.224 - Page 15, Column (16) - Page 12, Columns (2) and (4).
For 2001, Column (3) = (Page 14, Column (2), Line 5)/9
For years 2002-2009, same as 2001.
(4) Page 5a, Column (3) x Page 1, Column (3).
(5) Sum of Columns (2) through (4).
(6) To be based upon results of actual market valuation.
(7) Column (5) + Column (6).

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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)
1	06/30/97	$1,565	$250	$1,815	$832	$0	$832	$983	$386
2	1997	1,523	243	1,766	785	0	785	981	385
3	1998	1,406	224	1,631	695	0	695	936	367
4	1999	1,251	200	1,451	611	0	611	840	329
5	2000	1,060	169	1,229	557	0	557	671	263
6	2001	942	150	1,092	509	0	509	584	229
7	2002	824	131	956	463	0	463	492	193
8	2003	706	113	819	435	0	435	384	151
9	2004	589	94	683	391	0	391	292	114
10	2005	471	75	546	348	0	348	198	78
11	2006	353	56	410	305	0	305	105	41
12	2007	235	38	273	262	0	262	11	4
13	2008	118	19	137	220	0	220	(84)	(33)
14	2009	(0)	(0)	(0)	184	0	184	(184)	(72)

Column Notes:
(2) See Page 4, Column (7) for 6/30/97 balance. For year end 1997-2009, Column (2) prior year - (Page 12, Column (3) current year x (Column (2) Line1/Column (4) Line 1)
(3) See Page 5, Column (2) for 6/30/97 balance. For year end 1997-2009, Column (3) prior year - (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 taxrate of .39225.

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	06/30/97	$1,815	$386	$1,429					
2	1997	1,766	385	1,381	$1,405	$77	($0.1)	2.4	$80
3	1998	1,631	367	1,264	1,322	146	(0.2)	4.6	150
4	1999	1,451	329	1,121	1,192	131	(0.2)	4.2	135
5	2000	1,229	263	965	1,043	115	(0.2)	3.6	118
6	2001	1,092	229	863	914	101	(0.1)	3.1	104
7	2002	956	193	763	813	89	(0.1)	2.8	92
8	2003	819	151	668	715	79	(0.1)	2.4	81
9	2004	683	114	568	618	68	(0.1)	2.0	70
10	2005	546	78	468	518	57	(0.1)	1.7	59
11	2006	410	41	369	418	46	(0.1)	1.3	47
12	2007	273	4	269	319	35	(0.0)	0.9	36
13	2008	137	(33)	169	219	24	(0.0)	0.6	25
14	2009	(0)	(72)	72	121	13	(0.0)	0.2	13

Return Component	Pre-Divestiture Year End 1995	Post-Divestiture Year End 1995
Capital Structure:		
LTD - Taxable	44.07%	44.07%
Preferred	3.56%	3.56%
Common Equity	52.37%	52.37%
	100.00%	100.00%
Cost Rates:		
LTD - Taxable	6.23%	6.23%
Preferred	5.69%	5.69%
Common Equity	9.20%	11.00%
Total Weighted Cost Rate	7.77%	8.71%
Reimbursement for Taxes on Equity Component	3.24%	3.86%
Total Rate of Return	11.01%	12.56%

Column Notes:

(2) See Page 13, Column (4).
(3) See 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 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).

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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	1997	$24	$186	$69	$117	$0	($6)	($4)	($2)	$23	$2	$0	$0	$0	$0	$164
2	1998	46	370	142	229	0	(15)	(9)	(6)	44	3	0	0	0	0	316
3	1999	40	371	150	221	0	(15)	(9)	(6)	43	3	0	0	0	0	302
4	2000	34	375	153	222	0	(15)	(9)	(6)	43	3	0	0	0	0	296
5	2001	51	382	150	232	0	(10)	(5)	(5)	43	3	0	0	0	0	326
6	2002	50	381	163	218	0	(10)	(5)	(4)	43	1	0	0	0	0	307
7	2003	50	358	152	206	0	(10)	(5)	(4)	43	0	0	0	0	0	295
8	2004	51	359	158	202	0	(9)	(6)	(4)	41	0	0	0	0	0	290
9	2005	52	359	157	202	0	(9)	(6)	(4)	41	0	0	0	0	0	292
10	2006	53	355	158	197	0	(9)	(6)	(3)	41	0	0	0	0	0	287
11	2007	48	361	164	197	0	(8)	(5)	(2)	35	0	0	0	0	0	278
12	2008	40	374	173	202	0	(8)	(5)	(3)	35	0	0	0	0	0	274
13	2009	36	327	156	170	0	(8)	(6)	(2)	33	0	0	0	0	0	237
14	2010	39	294	146	149	0	(7)	(5)	(3)	33	0	0	0	0	0	218
15	2011	39	217	113	104	0	0	0	0	18	0	0	0	0	0	161
16	2012	35	122	38	83	0	0	0	0	15	0	0	0	0	0	133
17	2013	33	123	39	84	0	0	0	0	15	0	0	0	0	0	132
18	2014	33	126	40	85	0	0	0	0	8	0	0	0	0	0	127
19	2015	36	128	41	86	0	0	0	0	0	0	0	0	0	0	122
20	2016	36	99	32	68	0	0	0	0	0	0	0	0	0	0	104
21	2017	36	96	30	66	0	0	0	0	0	0	0	0	0	0	102
22	2018	36	54	15	39	0	0	0	0	0	0	0	0	0	0	76
23	2019	36	55	15	40	0	0	0	0	0	0	0	0	0	0	76
24	2020	39	13	0	12	0	0	0	0	0	0	0	0	0	0	51
25	2021	39	13	0	13	0	0	0	0	0	0	0	0	0	0	52
26	2022	39	13	0	13	0	0	0	0	0	0	0	0	0	0	52
27	2023	39	14	0	13	0	0	0	0	0	0	0	0	0	0	52
28	2024	39	14	0.2	14	0	0	0	0	0	0	0	0	0	0	53
29	2025	41	14	0.2	14	0	0	0	0	0	0	0	0	0	0	56
30	2026	32	0	0.2	0.2	0	0	0	0	0	0	0	0	0	0	32
31	2027	26	0	0.2	0.2	0	0	0	0	0	0	0	0	0	0	27
32	2028	26	0	0.2	0.2	0	0	0	0	0	0	0	0	0	0	27
33	2029	26	0	0.0	0.0	0	0	0	0	0	0	0	0	0	0	26

Column Notes:
(All Sources based upon estimates of Variable Costs)
(2) (Page 6, Column (5) + Page 7, Column (7)) x Page 1, Column (3)
(3) See Page 8 x Page 1, Column (3).
(5) Column (3) - Column (4).
(7) Page 10, Column (5) x Page 1, Column (3).
(9) Column (7) - Column (8).
(10) Page 11, Column (7) x Page 1, Column (3).
(16) Sum of Columns (2), (5), (6), (9), (10), (11), (12), (13), (14), and (15).

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Schedule 2
Page 1 of 3

Impact of Contract Termination Deferral on Starting Balance of Sunk Commitments

New England Power Company
($ Millions)

	1997 Annual	1997 Monthly
Continuation of W-95(S)		
Depreciation of Generating Plant	$95.3	$7.9
Amortization of Regulatory Assets	50.4	4.2
Total	$145.7	$12.1
Amortization per CTC		
Total	$103.4	$8.6
Excess Amortization in W-95(S)	$42.3	$3.5
Cumulative Excess Amortization in W-95(S)	$42.3	$3.5

	1998 Annual	1998 Monthly
Continuation of W-95(S)		
Depreciation of Generating Plant	$110.2	$9.2
Amortization of Regulatory Assets	34.2	2.9
Total	$144.5	$12.0
Amortization per CTC		
Total	$140.4	$11.7
Excess Amortization in W-95(S)	$4.0	$0.3
Cumulative Excess Amortization in W-95(S)	$46.3	$0.3

	1999 Annual	1999 Monthly
Continuation of W-95(S)		
Depreciation of Generating Plant	$111.4	$9.3
Amortization of Regulatory Assets	34.2	2.9
Total	$145.7	$12.1
Amortization per CTC		
Total	$185.4	$15.5
Excess Amortization in W-95(S)	($39.8)	($3.3)
Cumulative Excess Amortization in W-95(S)	$6.5	($3.0)

	2000 Annual	2000 Monthly
Continuation of W-95(S)		
Depreciation of Generating Plant	$112.6	$9.4
Amortization of Regulatory Assets	34.2	2.9
Total	$146.9	$12.2
Amortization per CTC		
Total	$227.4	$19.0
Excess Amortization in W-95(S)	($80.6)	($6.7)
Cumulative Excess Amortization in W-95(S)	($74.0)	($9.7)

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Schedule 2
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Reconciliation Adjustment - Illustrative Calculation

The Narragansett Electric Company Share

	Revenue Adjustments					New England Power Company Variable Cost Adjustments																
Year (1)	Estimated Kwh Delivered (2)	Actual Kwh Delivered (3)	Delta Kwh Delivered (4)	Termination Charge Billed (5)	Narragansett Revenue Excess/ (Shortfall) (6)	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)	NEP Actual Total Variable Component (20)	Delta Variable Component (21)	Narragansett Share of Delta Variable Component (22)	Narragansett Annual Reconciliation Adjustment Excess/ (Shortfall) (23)
1997	2,379	2,379	0	2.80	$0	$104	$34	$186	$80	$0	(86)	(94)	$23	$2	$0	$0	$0	$0	$104	$0	$0	$0
1998	4,879	4,879	0	2.80	0	316	46	370	142	0	(16)	(9)	44	3	0	0	0	0	316	0	0	0
1999	5,013	5,013	0	2.80	0	302	48	371	150	0	(15)	(9)	43	3	0	0	0	0	302	0	0	0
2000	5,106	5,106	0	2.80	0	296	34	375	153	0	(15)	(9)	43	3	0	0	0	0	296	0	0	0
2001	5,163	5,163	0	2.48	0	325	51	382	150	0	(16)	(6)	43	3	0	0	0	0	325	0	0	0
2002	5,232	5,232	0	2.33	0	307	50	381	163	0	(16)	(6)	43	1	0	0	0	0	307	0	0	0
2003	5,298	5,298	0	2.20	0	296	50	380	152	0	(16)	(6)	43	0	0	0	0	0	295	0	0	0
2004	5,366	5,366	0	2.11	0	290	51	380	190	0	(9)	(6)	41	0	0	0	0	0	290	0	0	0
2005	5,429	5,429	0	2.04	0	282	52	369	157	0	(9)	(6)	41	0	0	0	0	0	282	0	0	0
2006	5,496	5,496	0	1.95	0	307	53	365	180	0	(9)	(6)	41	0	0	0	0	0	307	0	0	0
2007	5,562	5,562	0	1.84	0	278	48	361	164	0	(8)	(6)	35	0	0	0	0	0	278	0	0	0
2008	5,628	5,628	0	1.76	0	274	48	374	173	0	(8)	(6)	35	0	0	0	0	0	274	0	0	0
2009	5,695	5,695	0	1.86	0	237	36	327	186	0	(8)	(6)	33	0	0	0	0	0	237	0	0	0
2010	5,763	5,763	0	0.84	0	210	38	294	146	0	(7)	(6)	33	0	0	0	0	0	210	0	0	0
2011	5,864	5,864	0	0.61	0	161	38	217	113	0	0	0	18	0	0	0	0	0	161	0	0	0
2012	5,946	5,946	0	0.50	0	133	35	122	38	0	0	0	15	0	0	0	0	0	133	0	0	0
2013	6,029	6,029	0	0.49	0	132	33	123	39	0	0	0	15	0	0	0	0	0	132	0	0	0
2014	6,114	6,114	0	0.46	0	127	33	126	40	0	0	0	0	0	0	0	0	0	127	0	0	0
2015	6,199	6,199	0	0.44	0	122	36	128	41	0	0	0	0	0	0	0	0	0	122	0	0	0
2016	6,286	6,286	0	0.37	0	104	36	99	32	0	0	0	0	0	0	0	0	0	104	0	0	0
2017	6,374	6,374	0	0.36	0	102	36	96	30	0	0	0	0	0	0	0	0	0	102	0	0	0
2018	6,463	6,463	0	0.26	0	75	36	54	15	0	0	0	0	0	0	0	0	0	75	0	0	0
2019	6,554	6,554	0	0.26	0	76	36	56	16	0	0	0	0	0	0	0	0	0	76	0	0	0
2020	6,646	6,646	0	0.17	0	51	38	13	0	0	0	0	0	0	0	0	0	0	51	0	0	0
2021	6,739	6,739	0	0.17	0	52	38	13	0	0	0	0	0	0	0	0	0	0	52	0	0	0
2022	6,833	6,833	0	0.17	0	52	38	13	0	0	0	0	0	0	0	0	0	0	52	0	0	0
2023	6,929	6,929	0	0.17	0	52	38	14	0	0	0	0	0	0	0	0	0	0	52	0	0	0
2024	7,026	7,026	0	0.17	0	53	38	14	0	0	0	0	0	0	0	0	0	0	53	0	0	0
2025	7,124	7,124	0	0.17	0	56	41	14	0	0	0	0	0	0	0	0	0	0	56	0	0	0
2026	7,224	7,224	0	0.10	0	32	32	0	0	0	0	0	0	0	0	0	0	0	32	0	0	0
2027	7,326	7,326	0	0.08	0	27	26	0	0	0	0	0	0	0	0	0	0	0	27	0	0	0
2028	7,427	7,427	0	0.08	0	27	26	0	0	0	0	0	0	0	0	0	0	0	27	0	0	0
2029	7,531	7,531	0	0.08	0	26	26	0	0	0	0	0	0	0	0	0	0	0	26	0	0	0

Column Notes:

(2) See Schedule 1, Page 1, Column (6).
(3) For demonstration purposes Actual kwh's delivered assumed to equal the Estimated kwh's delivered.
(4) Column (3) - Column (2).
(5) See Schedule 1, Page 1, Column (10).
(6) Column (4) x Column (5).
(7) See Schedule 1, Page 15, Column (16).
(8)-(19) For demonstration purposes Actual Variable Components are assumed to equal the Estimated Variable Components illustrated on Schedule 1, Page 15.
(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).
(21) Column (20) - Column (7).
(22) Column (21) x 22.4%.
(23) Column (6) - Column (22).

06/26/97

The Narragansett Electric Company

Reconciliation Account - Illustrative Calculation

	The Narragansett Electric Company Account						
Year (1)	Reconciliation Adjustment (2)	Adjustment for Difference Between 9.2% ROE Pre-Divestiture and 11% ROE Post-Divestiture (3)	Adjustment for Difference Between Amortization per W-95(S) and Amortization per CTC (4)	Annual Shortfall/ (Excess) (5)	Annual Pre-Tax Return on Balance (6)	Collection of Prior Year Balance Including Interest (7)	End of Year Account Balance (8)
1997	$0	$0	$0	$0	$0	NA	$0
1998	0	0	0	0	0	NA	0
1999	0	0	0	0	0	NA	0
2000	0	0	0	0	0	NA	0
2001	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0
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
2010	0	0	0	0	0	0	0
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

Column Notes:

(2) See Schedule 2, Page 1, Column (23) x -1.
(5) Sum Columns (2) through (4).
(6) Column (8) prior year x return pursuant to Section 1.1.2.
(7) Column (8) prior year x -1 + Column (6) current year.
(8) Prior year Column (8) + current year Sum Column (5) through (7).

05/28/97

Reconciliation of FAS 106 and 87
Upon Divestiture

$ in Millions

	Actual After Date of Divestiture
One-Time Adjustments Upon Divestiture:	
(1) Post Retirement Health Care Benefits-	
Unrecognized FAS 106 Gain or (Loss)	
(a) Unrecognized Net Gain/(Loss) associated with FAS 106	
NEP x 95%	-
NARR x 15%	-
NEPSCO x 50%	-
Total Unrecognized Net Gain/(Loss) allocated to NEP	-
(b) Generation Related Portion	84.10%
(c) Total Unrecognized Net Gain/(Loss) allocated to Generation	-
(2) Pensions -	
Unrecognized FAS 87 Gain or (Loss) *	
(d) Unrecognized Net Gain/(Loss) associated with FAS 87	
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEP x 95%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NARR x 15%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEPSCO x 50%	-
Total Unrecognized Net Gain/(Loss) allocated to NEP	-
(e) Less: Unrecognized Prior Service Costs associated with FAS 87	
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEP x 95%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NARR x 15%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEPSCO x 50%	-
Total Unrecognized Prior Service Costs allocated to NEP	-
(f) Less: FAS 87 Transition Liability	
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEP x 95%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NARR x 15%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEPSCO x 50%	-
Total FAS 87 Transition Liability allocated to NEP	-
(g) Plus: FAS 87 Transition Asset	
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEP x 95%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NARR x 15%	-
(NEES Union x __%) + (NEES Non-Union x __%) + (SERP x __%) = NEPSCO x 50%	-
Total FAS 87 Transition Asset allocated to NEP	-
(h) Net Unrecognized Gain/(Loss) Associated with Pension	-
(i) Generation Related Portion	84.10%
(j) Net Unrecognized Gain/(Loss) allocated to Generation	-

* For the purpose of this reconciliation the unrecognized FAS 87 gains or losses shall be the amount of the net unrecognized transition obligation, prior service cost, and unrecognized FAS 87 gains or losses only to the extent that such gains or losses exceed five percent of the greater of plan assets or liabilities.

Row Notes:
(a) Per actual accounting and actuarial records.
(b) = Generation allocator based upon salaries and wages.
(c) = (a) x (b)
(d), (e), (f), (g) Per actual accounting and actuarial records.
Specific Company balances for Union, Non-Union, and SERP plans will be allocated by multiplying the total NEES balance for these plans by the ratio of the Company liability to the total NEES liability, by plan.
(h) = (a) - (b) - (c) + (d)
(i) See (b) above.
(j) = (h) x (i)

Schedule 3
Page 2 of 4

Reconciliation of NEEI Stranded Costs
Upon Sale of NEEI Assets

$ in Millions

	6/30/97 Estimate (A)	Actual (B)	Delta = NEEI Reconciliation (C)
Regulatory Asset Calculation:		*To Be Determined Upon Sale*	
(1) Market Value (After-Tax)			
Pre-Divestiture: Cost Center Ceiling			
Present Value of Reserves	$57.0		
Income Tax Adjustment	(4.2)		
Cost Center Ceiling withTax Adj.	52.7	$0.0	
or			
Post Divestiture: Actual Net Proceeds			
Actual Market Value Realized, after-tax	0.0	52.7	
Equals Market Value	52.7	52.7	$0.0
(2) Book Basis			
Unamortized Balance	181.8	181.8	0.0
Less: Related Deferred Tax	51.7	51.7	0.0
Net Book Basis	130.1	130.1	0.0
(3) Write-Off			
Net of Taxes	77.4	77.4	0.0
Tax Adjustment	48.5	48.5	0.0
Write-Off Including Taxes	125.9	125.9	0.0
(4) Estimated Unrecovered 1997 Loss	31.9	31.9	0.0
(5) Total Revenue Requirement	$157.7	$157.7	$0.0

Row Notes:
(1) For estimated market value, use cost center ceiling test , after-tax.
For actual market value, use actual after-tax proceeds.
(2) For estimate use 12/31/97 balances. Update to actual upon sale.
(3) ((Row (1) - Row (2)) x -1)/(1-.39225)
(4) For estimate use 1997 estimated loss. Update to actual upon sale.
(5) Row (3) + Row (4).

Column Notes:
(A) Estimated 12/31/97 balance.
(B) Actual components at time of sale of assets. For illustrative purposes, actuals assumed to equal estimates.
(C) Column (A) - Column (B) = NEEI Reconciliation

Schedule 3
Page 3 of 4

Power Contract Buyout Incentive
Associated with Divestiture

$ in Millions

			Illustrative Example Only
	Divestiture Transaction:		
(1)	Total NEP Proceeds from Divestiture	$0	*$1,100*
	NEP Power Contracts Assumptions:		
(2)	Annual Buyout Payments	0	*144*
(3)	NPV of Annual Buyout Payments	0	*795*
(4)	Net Proceeds Realized for Assets	0	*305*
(5)	Proceeds Necessary to Realize 125% Net Book Value	0	*1,370*
(6)	Net Value Attributable to Power Contracts	0	*(1,065)*
(7)	NPV of Above-Market Power Contracts in CTC	0	*(1,415)*
(8)	Total Power Contracts Savings	0	*(349)*
(9)	10% Buyout Incentive	0.0	*34.9*
(10)	Narragansett Share	22.4%	*22.4%*
(11)	Narragansett Share of Incentive	$0.0	*$7.8*

Line Notes:

(1) Actual sale proceeds realized through divestiture.
(2) Actual annual power contract buyout payments.
(3) NPV, at the time of divestiture, of Line (2) for stipulated term of buyout payments 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). For this example, the discount rate used equals the pre-tax return of 12.56% pursuant to Section 1.1.2.
(4) Line (1) - Line (3).
(5) Actual net book value of fossil and hydro units upon divestiture x 125%.
(6) Line (5) - Line (4).
(7) NPV, at the time of divestiture, of Schedule 1, Page 15, Column (5), remaining years only, 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 in Page 4 of this Schedule, even if actual market prices are different. For this example, the discount rate used equals the pre-tax return of 12.56% pursuant to Section 1.1.2.
(8) Line (7) - Line (6).
(9) Line (8) x -1 x 10%
(10) The Narragansett Electric Company's share of NEP stranded costs.
(11) Line (9) x Line (10).

Schedule 3
Page 4 of 4

Power Contract Buyout Incentive
Associated with Divestiture

$ in Millions

Market Price Assumptions *

	cents/kwh
1997	2.24
1998	2.34
1999	2.46
2000	2.46
2001	2.60
2002	2.88
2003	2.97
2004	3.07
2005	3.16
2006	3.26
2007	3.36
2008	3.48
2009	3.59
2010	3.70
2011	3.82
2012	3.93
2013	4.05
2014	4.16
2015	4.28
2016	4.39
2017	4.51
2018	4.62
2019	4.74
2020	4.85
2021	4.97
2022	5.09
2023	5.20
2024	5.32
2025	5.43
2026	5.55
2027	5.67
2028	5.79
2029	5.90

* Note: Market Price Assumptions are fixed for purposes of the calculation of the Power Contract Buyout Incentive. With respect to the Hydro-Quebec contract, the market values assumed for 1997, 1998, 1999 and 2000 are also fixed at $7 M, $8 M, $10 M and $12 M per year, respectively, for purposes of the calculation of the Power Contract Buyout Incentive.

05/27/97

NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION

Project #	*Station*	*Project Title*	*1996 Costs Capital & Removal*	*Spending Purpose*
12260	Vernon	Vernon SPCC-Oil/Water Separator	144,952.66	United States Environmental Protection Agency Regulations 40 CFR 109 and 112 require the prevention of potential spills from reaching waterways.
12354	BP	BP 3 Turbine Water Induction	165,451.51	The installation of motor operators on the Brayton Point Unit 3 extraction line block valves was recommended as part of the overall turbine water induction protection program. The installation of the motor operators will further enhance the systems already in place which protect against turbin water induction.
12413	BP	BP Continuous Emissions Monitors	230,481.39	As mandated by the 1990 Clean Air Act Amendment, these units must be equipped with continuous emission monitoring systems in order to operate beyond December 31, 1994
12460	BP	BP 3 Low NOx Burners	1,022,227.55	The 1990 Clean Air Act Amendment requires that Brayton Point Unit 3 be in compliance with NOx emissions regulations by May 31, 1995
12476	BP	BP Equipment Retirement and Removal -1994	199,794.20	To create space for future projects, to eliminate operation and maintenance and to prevent equipment from becoming a safety hazard

**NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION**

Project #	Station	Project Title	1996 Costs Capital & Removal	Spending Purpose
12661	BP	BP 1 & 2 Control Replacements	153,467.96	The existing control systems have reached the end of their useful lives, and are now causing decreased unit availability, increased maintenance costs, and degradation of unit efficiency
12726	BP	BP Fire Protection/City Water	175,618.47	To upgrade the level of fire protection at Brayton Point Station in areas considered essential for power production and personnel safety. This project is part of the overall Thermal Stations Fire Protection improvement program which has been reviewed and received concurrence from both management and our insurance carrier
12792	SH	SH Equipment Removal/Retirement	550,118.85	The amount of previously retired and abandoned equipment has increased at Salem Harbor over the past years due to many improvements at the station. This equipment has been and will continue to deteriorate posing potential hazards while diminishing the overall appearance of the plant. Abandoned equipment affects normal station operations by impeding the plant operators who must work around this equipment and it unnecessarily adds to the complexity of plant systems

**NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION**

Project #	Station	Project Title	1996 Costs Capital & Removal	Spending Purpose
14741	BP	BP 3 Old Precipitator Rebuild	167,152.40	The existing precipitator internals have been inspected and have been determined to be irreparable. With New England Power's intention to burn low sulfur coal to comply with Massachusetts Acid Rain Law, proper operation of precipitator internals will be necessary to ensure compliance with particulate emissions standards
15163	BP	Ash Separation Handling	1,462,516.88	The ash separation and handling facility will allow processing flyash from the coal fired units Flyash coming from the Unit 1-3 precipitators will be processed to remove a portion of the unburned carbon from the coal flyash The processed ash product will be sold as cement additive.
15200	BP	BP Coal Conveyors	187,208.27	Use of compliance coal will overload the existing coal conveyor drives due to the increased coal volumes required. Replacement and upgrade of the coal conveyor motor control center and cable replacement for new coal conveyor drive systems (separate project)

**NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION**

Project #	Station	Project Title	1996 Costs Capital & Removal	Spending Purpose
15284	BP	Bulldozer Maintenance Garage	123,345.82	Currently all bulldozer maintenance activities are required to be performed out of doors throughout the entire year either on the coal pile or on the coal pile runoff roadway. These activities include all oil changes, transmission PM's and blade maintenance. As the station uses 5 machines, these activities occur weekly and involve handling over 100 gallons of oil each time. By providing a building all these activities will occur in an enclosed environment, minimizing the potential for an oil release. In addition, the plant will be capable of performing maintenance work that requires the entire machine be sent offsite.
15335	BP	BP Cell 9 Removal	331,719.05	Massachusetts Department of Environmental Protection (MDEP) Permit requires installation of an approved closure cap.
15512	Vernon	Vernon 9 & 10 Governor Replacement	231,737.60	This work is being performed as part of the Hydro Automation Program. The Vernon #9 and #10 governors are at the end of their useful service life. It is necessary to replace the governors now before the full station automation occurs, scheduled for late 1996.
15552	BP	BP Turbine Lube Oil Piping	116,154.04	The piping between the turbine lube oil storage tanks and the Unit 1,2,3 & 4 lube oil tanks is corroded and is no longer serviceable.

**NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION**

Project #	Station	Project Title	1996 Costs Capital & Removal	Spending Purpose
15625	Bellows	Bellows Rack Rake Replacement	176,595.78	The rack rake has reached the end of its' useful life with costly repairs in terms of repair hours and outside vendor expense.
15875	Wilder	Wilder Automation Project	1,452,488.60	The Wilder Automation Project is part of the overall Hydro Automation Program. The program will allow for a reduction in staffing and optimization of river operation.
16090	Hydro-Various	River Decision Support System	372,855.69	The River Decision Support System is part of the Hydro Automation Program. The system will improve efficiencies in dispatching reservoirs and power stations. The system will be used as a managing tool by river operations and also by the Relicensing Team for study purposes
16310	BP	BP Floor Drain Oil Water Separator	217,359.52	Installing an oil water separator will remove potential oil contamination prior to entering the Waste Water Treatment System.

NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION

Project #	*Station*	*Project Title*	*1996 Costs Capital & Removal*	*Spending Purpose*
16452	BP	BP Process Drains Relocation	157,399.09	The Unit 1,2 & 3 turbine oil tanks currently vent lube oil mist onto the turbine hall roof. The lube oil mist that collects on the roof discharges with storm water into the condenser seal pits and into Mount Hope Bay. Installing a mist eliminator on each unit will prevent lube oil mist from collecting on the turbine hall roof. The Unit 1,2 & 3 circulating water pump house and Unit 4 screen well pump house floor drain sump pumps have the potential for discharging oil directly into the Taunton River. Installing a skimmer device will solve the problem of removing a potential oil or grease discharge prior to discharing into the Taunton River or Unit 4 intake canal
16717	BP	Rough Terrain Crane	120,136.08	A crane is required for station maintenance . A variety of options were explored and the least cost option selected. This option has a 2-1/2 year break-even point as compared to the existing rental agreement.
16974	Gloucester	Gloucester Diesel Fire Detection	102,113.73	Install a new fire detection system within the diesel enclosures to permit monitoring for potential fire conditions. This work was conducted to enhance safety and reduce possible losses as requested and agreed to with Arkwright Insurance

**NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION**

Project #	*Station*	*Project Title*	*1996 Costs Capital & Removal*	*Spending Purpose*
15832	Vernon	Vernon Trash Boom Replacement	180,557.66	Existing trash booms at Vernon are deteriorating to the condition that replacement is required
12414	SH	SH Continuous Emissions Monitors	138,180.24	As mandated by the 1990 Clean Air Act Amendment, these units must be equipped with continuous emission monitoring systems in order to operate beyond December 31 1994
12454	SH	SH 4 Combustion Controls	491,628.32	The existing 1960s vintage combustion controls cannot maintain combustion conditions necessary to limit NOx and CO emissions as required by the Clean Air Act. The present controls cannot be modified due to a lack of component availability Future manufacturer support for the existing control system will not be available
15691	SH	SH Recycled Water System	100,880.32	The new pump and piping will allow waste water effluent to be reused for boiler washing, stack washing, bottom ash system makeup, fly ash system makeup, coal pile dust suppression, and general cleaning. The current arrangement does not have the flow requirements to allow for constant recycling of effluent, resulting in city water being used in its place. The new system will mkae recycling convenient and dependable, which will greatly reduce the cost of city water.

NEPCo - 1996 CWIP SPENDING
FOR THERMAL and HYDRO PRODUCTION

Project #	Station	Project Title	1996 Costs Capital & Removal	Spending Purpose
16000	Vernon	Vernon Transformers Replacement	256,777.50	Two of the 2.4/69kV transformers are 1909 vintage, water-cooled units beyond their life expectancy. Transformation from 2.4 to 13.8kV will eliminate 150 degree phase difference between the two 2.4kV buses, removing a potential source of costly operating errors and equipment damage. The full output of the station will go through the two new 13.8/69kV transformers in the outdoor switch-yard.

Detail of
Early Retirement,
Employee Severance and Retraining Costs
Resulting From Divestiture *

$ in Millions

Assumptions:
7.25% Discount rate, Updated Eligibility, Lump Sum Feature, Updated Acceptance Profile

Accounting Cost:	5 & 5 plus $750		
	Non Union	Union	Total
Early Retirement			
Additional Benefits			
Pension	$25.1	$27.0	$52.1
Health		6.5	6.5
Curtailment effects			
Pension	0.2	0.3	0.5
Health	5.7	6.5	12.2
Subtotal Early Retirement	31.0	40.3	71.3
Terminations & Employee retraining			
Payments	7.0	2.0	9.0
Curtailment effects			
Pension	(3.6)		(3.6)
Health	15.0		15.0
Subtotal Terminations & Retraining	18.4	2.0	20.4
Total Program Costs	49.4	42.3	91.7
Less Estimated amount included in Contract Termination Charge already (both early retirement & severance)			(6.0)
Net Program Costs			$85.7
Position Reductions:			
# of employees eligible	295	583	878
# of employees accepting	187	432	619
# of employees to be severed	200	100	300
Total Reductions	387	532	919

* Costs include those of New England Power Company, Massachusetts Electric Company, The Narragansett Electric Company, and New England Power Service Company. Reductions include positions in the generation, transmission, and distribution businesses.

Attachment 2

Agreement to Credit Tariff 1 Fuel Clause with Revenues Representing the Fixed Cost Contribution from Departing Customers

To ensure that Tariff No. 1 customers are held harmless from contract termination of any Tariff No. 1 customer, and to recognize the changing nature of NEP's sales due to the restructuring proposals contained in the Mass. Electric settlement, NEP agrees to credit the Fuel and Purchased Economic Power Adjustment Clause ("Fuel Clause") monthly, with the pro rata share that any departing customer would have contributed to the Fixed Costs included in the fuel clause. The Pro Rata share will be defined as the 1991-1995 base revenue contribution of any departing customers(s) taken as a percentage of NEP's total base revenues during that period.

Fixed Costs are defined to include:

1) NEEI Payments;
2) Pipeline Demand Charges net of any mitigation (including OSP pipeline charges);
3) Fixed Costs associated with purchases from alternate energy suppliers specified on Page 2 of this Attachment;
4) Fixed coal transportation charges;
5) DOE Decontamination and Decommissioning costs; and
6) Final Nuclear Fuel Core Amortization for Millstone and Seabrook.

The definition of Fixed Costs included in NEP's Fuel Clause shall include the fixed costs associated with purchases from the following alternate energy suppliers:

Altresco Pittsfield
Pawtucket Power
NELP Johnston Landfill
Ogden Haverhill Landfill
RESCO Saugus
RESCO North Andover
Refuse Fuel Associates - Lawrence
Turnkey (Rochester) NH
Wheelabrator Millbury
Barre Landfill
Four Hills (Nashua) Landfill
Lawrence Hydro
Mascoma Hydro
MWRA - Cosgrove Wachusett Hydro
Pontook Hydro
Clark University

Attahcment 3

Service Agreement For

Network Integration Transmission Service

1.0 This Service Agreement (Agreement), dated as of February 1, 1997, is entered into, by and between New England Power Company (the "Transmission Provider"), and The Narragansett Electric Company ("Transmission Customer") for the purpose of implementing wholesale competition or retail access for the Transmission Customer's retail customers pursuant to the Rhode Island Utility Restructuring Act of 1996 (URA).

2.0 The Transmission Customer has been determined by the Transmission Provider to have a valid request for Firm Transmission Service under the Transmission Provider's Open Access Transmission Tariff ("Tariff").

3.0 Service under this Agreement shall be provided in accordance with the Retail Access Schedule, which together with other capitalized terms in this paragraph are defined in the Stipulation and Agreement filed with the Commission in Docket ER97-680-000. For the period from July 1, 1997 through the Contract Termination Date, service under this agreement shall only apply to kilowatthours delivered, but not sold, by the Transmission Customer in the Transmission Customer's Service Area. After the Contract Termination Date, service under this agreement shall apply to all kilowatthours delivered in the Transmission Customer's Service Area. Service under this Agreement shall not be terminated before the date that the Contract Termination Charges set forth in the Stipulation and Agreement and the Amendment to the Service Agreement between the Transmission Customer and the Transmission Provider under theTransmission Provider's FERC Electric Tariff, Original Volume No. 1 (Amendment) are fully recovered from the Transmission Customer. Following that date service under this Agreement shall continue until modified or terminated upon the written consent of both parties or upon five years advance written notice by either party to the other.

4.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of the Tariff, this Service Agreement and Exhibit 1 to this Service Agreement. 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 Provider, its successors or assigns, Transmission Provider, its successor or assigns, providing service over the transmission facilities covered by this Agreement shall collect the unrecovered balance of the Contract Termination Charges as a surcharge under this Agreement to the Transmission Customer or to any consumer taking delivery of electric energy over the transmission or distribution facilities of the Transmission Customer.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

New England Power Company
Attention: Director, Transmission Marketing
25 Research Drive
Westborough, MA 01582

Transmission Customer:

The Narragansett Electric Company
25 Research Drive
Westborough, MA 01582

6.0 The Tariff, as amended, changed, modified or superseded by filings with the Federal Energy Regulatory Commission, is incorporated herein and made a part hereof.

7.0 The obligations under this Agreement may be assigned only with the express written consent of the other party, which consent shall not be unreasonably withheld, provided, however, that the Transmission Provider shall not be obligated to consent to any assignment that adversely affects the ability of Transmission Provider to recover from the Transmission Customer the payments required to be made under the Tariff, this Service Agreement, including any Contract Termination Charges that may be billed to Transmission Customer pursuant to Section 4.0 above, and Exhibit 1 to this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: Arnold H. Turner — Vice President — May 29, 1997
Name Arnold H. Turner — Title — Date

Transmission Customer:

By: Robert L. McCabe — President — May 29, 1997
Name Robert L. McCabe — Title — Date

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Exhibit 1
Specifications for Network Integration Transmission Service

1. Term of Service: ________________________________

   Start Date: Effective date of the Service Agreement.

   Termination Date: As specified in the Service Agreement.

2. List of Network Resources and Point(s) of Receipt.

   To be supplied by the Customer upon effectiveness of this Service Agreement.

3. a) List of Point(s) of Delivery including and identifying Remote Delivery Point(s).

      See Attachment 1

   b) List of Metering Point(s) when they differ from Point(s) of Delivery.

      To be provided.

4. List of non-Network Resource(s), to the extent known today.

   To be supplied by the customer upon effectiveness of this Service Agreement.

5. Ancillary Services Requested or Proof of Satisfactory Arrangements for Ancillary Services.

   To be supplied by the customer upon effectiveness of this Service Agreement.

6. Identity of Designated Agent: See Attachment No. 2.

   a) Authority of Designated Agent

   b) Term of Designated Agent's authority

   c) Division of responsibilities and obligations between Transmission Customer and Designated Agent

7. Other specified provisions:

   A. Billing will include any applicable charges in accordance with the rates, terms, and conditions of the Tariff.

   B. The Transmission Provider 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 Stipulation and Agreement of even date and the Amendment. Service under this Agreement is conditioned on the Commission's approval of the Stipulation and Agreement and the Amendment filed on May 30, 1997.

C. In no event shall the Transmission Provider bypass the Transmission Customer's distribution facilities and interconnect directly with a retail customer.

Attachment 1

Points of Delivery

Admiral Street Substation
Bristol Substation
Clarkson Street Substation
Davisville Substation
Drumrock Substation
Farnum Pike Substation
Franklin Square Substation
Johnston Substation
Kent County Substation
Kenyon Substation
Lincoln Ave. Substation
Mink Street Substation
Old Baptist Road Substation
Phillipsdale Substation, Transformer #1 (Remote)*
Phillipsdale Substation, Transformer #2 *
Pontiac Substation
Sockanosset Substation
South Street Station
Tiverton Substation (Remote)
Wampanoag Substation
Warren Substation
West Cranston Substation
West Kingston Substation
Wolf Hill Substation
Wood River Substation

* Phillipsdale Substation is served off both the Company's transmission system and EUA's transmission system.

Attachment 2

The Narragansett Electric Company

1. Identity of Designated Company

   The Designated Agents may be either the suppliers to the Transmission Customer's retail customers provided that the suppliers are members of the New England Power Pool (NEPOOL) or the NEPOOL members with whom the supplier's have contracted to provide such supplies. The identity of the Designated Agents may be modified to reflect changes in NEPOOL rules.

2. Authority of the Designated Agent

   The Transmission Customer assigns its rights under the Tariff to the Designated Agent(s) as follows: A Designated Agent(s) shall have full authority to designate network resources, delete network resources, and purchase resources other than network resources for delivery to that portion of the Network Load that is assigned to that Designated Agent. A Designated Agent will be assigned all the Transmission Customer's firm allocated limited interface rights in proportion to its assigned ratio of Network Load, including the authority to schedule transactions over these limited interfaces. A Designated Agent will also have the authority to integrate its assigned portion of the Transmission Customer's load and associated resources with the loads and resources of other transmission customers who have similarly designated rights to the same agent, for all NEPOOL purposes.

3. Term of Designated Agent's Authority

   The Transmission Customer may name another Designated Agent for purposes of this Tariff, to the extent that a portion of the Network Load changes suppliers.

4. Division of responsibilities and obligations between Transmission Customer and Designated Agent

   The Transmission Customer is responsible for payment, operating its distribution system and maintaining proper load power factors in accordance with the Tariff, and any other obligations relating to the Transmission Customer's physical distribution system or its interconnections with the Transmission Provider's transmission system, or other transmission systems.

   The Designated Agent is responsible for designating network resources, delivering network resources to the Transmission Provider's Transmission System, scheduling purchases from non-network resources, arranging for required redispatch of network resources, and supplying ancillary services, for the portion of the Transmission Customer's load that it has been assigned.

Attachment 4

Evaluation of FERC's Seven Factor Test

Table of Contents

Exhibit A -- Page 1

I. Overview of Federal and State Jurisdictional Requirements per FERC Order 888

In its Order 888, the Federal Energy Regulatory Commission ("FERC") addressed the issue of Federal and State jurisdiction over retail transmission by defining what constitutes local distribution. The Commission exercised exclusive jurisdiction over unbundled transmission in interstate commerce used by public utilities for retail wheeling up to the point of local distribution.[1] To determine the jurisdictional line for retail access purposes, FERC proposed a seven factor test of local distribution. This test of functional and technical characteristics of facilities would define local distribution facilities and thus would demarcate the line between federal and state jurisdiction. (See FERC Stats & Regs. ¶ 31,036, pp. 31,770-85). The seven factors are as follows:

(1) Local distribution facilities are normally in close proximity to retail customers.

(2) Local distribution facilities are primarily radial in character.

(3) Power flows into local distribution systems; it rarely, if ever, flows out.

(4) When power enters a local distribution system, it is not recognized or transported on to some other market.

(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.

(6) Meters are based at the transmission/local distribution interface to measure flows into

[1] In addition, the Commission exercised exclusive jurisdiction over all facilities, whether transmission or distribution, used for wholesale wheeling.

the local distribution.

(7) Local distribution systems will be reduced voltage.

Under Order 888, FERC will defer jurisdiction over local distribution facilities to state commissions if the state commissions apply the seven criteria set forth in Order 888. Accordingly, this report is prepared for use by the Rhode Island Public Utilities Commission, as well as FERC, when evaluating the jurisdictional separation between transmission and distribution facilities in Rhode Island. In addition, the NEES Companies have prepared a similar report for use by other state commissions in Massachusetts and New Hampshire. A consistent separation for each state will prevent gaps or overlaps in rate making and will protect against cross subsidies among customers that could otherwise occur if the states adopted different dividing lines between transmission and distribution plant. This report is consistent with the report that has been filed in Massachusetts and accepted by the Massachusetts Attorney General and other parties to Massachusetts Electric's proposed restructuring settlement agreement.

II. Summary of NEES System Structure

The NEES System has a unique structure. Most utilities are vertically integrated, and a single corporate entity owns the utility's generation, transmission, and distribution assets. However, the NEES system is organized differently along functional lines. New England Power Company (NEP), a separate subsidiary of the NEES system, owns or operates through an integrated facilities agreement, all of the system's generation and transmission assets and has contracted for all of the system's power purchases and transmission support obligations.[2] Although Narragansett owns the transmission facilities in Rhode Island, they are operated by NEP under a generation and transmission agreement ("G&T Agreement") that is subject to FERC's jurisdiction. The NEES retail companies, Massachusetts Electric, Granite State Electric, and Narragansett Electric obtain the power supplies they need to serve the retail customers in their service territories, as well as the transmission service to deliver that generation to their distribution system, through NEP under NEP's FERC Electric Tariff, Original Volume Number 1 (Tariff 1). The NEES retail companies separately own all of the distribution facilities needed to serve retail customers in their individual service territory.[3]

Thus, within NEES, transmission and distribution are generally operated by separate corporations. Outside of Rhode Island, transmission is separately owned by NEP. As stated above, in those instances where ownership is not separated, control and ratemaking authority over assets have been established through a FERC-jurisdictional integrated G&T Agreement between NEP and the distribution companies under Tariff 1. This G&T Agreement has been particularly significant for Narragansett Electric which owns all of the transmission assets and some generation assets in Rhode Island. In addition, the G&T Agreement has played a much smaller role for Massachusetts Electric

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[2] This is true with the exception of certain Qualifying Facilities (QF's) with capacity less than 1 megawatt, the output of which are purchased directly by the NEES retail companies under PURPA guidelines in each of the respective states in which the NEES retail companies operate. There also are some small, limited borderline sales agreements between Narragansett and EUA affiliates to serve isolated customers.

[3] NEP owns a very limited number of distribution facilities in Massachusetts Electric's service area. These lines are supported by Mass. Electric under its integrated facilities agreement with NEP.

which owns a relatively small number of transmission assets in Massachusetts and for NEP which owns a very small portion of the distribution assets in Massachusetts. In all of these instances, the generation and transmission assets are controlled and operated by NEP, and the distribution assets are controlled and operated by Massachusetts Electric Company pursuant to the integrated facilities G&T Agreement between NEP and each of the retail affiliates. Narragansett and Massachusetts Electric receive credits against their purchased power bills from NEP to compensate them for the costs of their transmission and generation facilities. Likewise, NEP receives compensation through the integrated facilities agreement from Massachusetts Electric for its use of the NEP owned distribution facilities.

Under the disaggregated structure of the NEES system, the costs of NEP's wholesale power supply and transmission investments and commitments are reflected in NEP's rates. NEP's rates also typically recover the costs associated with distribution facilities used for wholesale services. When NEP uses specific distribution facilities over which wholesale services occur to municipal customers or generators selling at wholesale, NEP compensates the retail affiliate under the integrated facilities contract for the use of those distribution facilities. As part of the G&T Agreement, these facilities also are under FERC jurisdiction. Thus, the rate recovery of investments and commitments for all wholesale wheeling are determined by FERC. In contrast, state commissions address directly the distribution costs and other costs associated directly with retail service.

III. Description of the NEES Retail Companies' Distribution Systems

The local distribution systems of the NEES Retail Companies are typically 5, 15, 25 or 35 kV voltage class systems. These systems are primarily radial in nature, serving retail load in the vicinity of the local distribution facilities. The local distribution systems are typically supplied from the 115 or 69 kV transmission system through one or more step-down transformers owned or controlled by NEP. Metering that measures the total kilowatt hours flowing into each local distribution area of the NEES retail companies is at the transmission/distribution interface, typically on the low voltage side of the step-down transformers.

Attachment 1 shows two types of common distribution systems for the NEES retail companies. Both are served from a transmission line, typically 69 kV or higher, through one or more step-down transformers. Type I distribution systems usually are comprised of 5, 15 or 35 kV voltage class feeders which serve retail customers directly through their service transformers. Several distribution feeders could emanate radially from each distribution substation. Type II distribution systems are generally 15, 25 or 35 kV voltage class distribution systems which serve some customers directly through the customer's service transformer and serve other customers through step-down transformers to a Type I distribution system which has 5 or 15 kV voltage class distribution feeders.

Both Type I and II distribution systems are primarily radial in nature. Although power may be supplied from more than one transmission/distribution interface, power flow is always into the geographic area served by the distribution facilities. Distribution facilities are not used to transmit bulk power from one geographic area to another; the power is consumed within the distribution service area.[4] The distribution circuit often terminates at an open switch to tie with an adjacent circuit for reliability and maintenance purposes; opening or closing tie points on the distribution system has no affect on the integrity or reliability of the bulk transmission system. Switching of distribution tie points may be manual or automatic and is done to restore service to customers in the event of an outage or to perform maintenance on equipment.

Attachment 2 is a list of Narragansett's transmission/distribution supply points. This attachment identifies each supply point by name, delivery pressure kV, and the type of distribution system supplied from that location.

IV. Application of the Seven Factors

The Narragansett distribution system is analyzed below, applying the seven factors identified by FERC:

(1) Local distribution facilities are normally in close proximity to retail customers.

Narragansett's distribution facilities are in close proximity to retail customers, as these are the circuits that emanate from local distribution substations and serve customers in a limited geographical area. These circuits typically are installed along public roads and private rights-of-way and serve adjacent customers.

[4] One minor exception relates to certain small, limited borderline sales agreements with EUA affiliates to serve isolated customers.

Attachment 3 shows an example of a Type I distribution system which has four distribution feeders, 68F1, 68F2, 68F3 and 68F4, which serve customers in the towns of Charlestown, Richmond, South Kingstown, and Westerly. These four distribution feeders are tied to adjacent feeders 86F1, 41F1, 30F1, 59F3 and 59F1 via open switches. Type II distribution systems generally cover a larger area than Type I distribution systems, but are still local in nature. Attachment 4, page 1 of 2, shows an example of a Type II distribution system made up of the 85T1, 85T2 and 85T3 lines out of Wood River Substation. This distribution system serves customers either directly or via Type I distribution systems in the towns of Hopkinton, Richmond, Westerly, and Charlestown as shown in Attachment 4, page 2 of 2.

(2) __Local distribution facilities are primarily radial in character.__

The distribution facilities of Narragansett are primarily radial in character, and serve a limited area from one or more transmission supply points. These facilities typically benefit the local area, and do not affect the operation or integrity of the transmission system other than as local load delivery points.

Type I distribution circuits are always radial, but may have normally open ties with similar circuits. Attachment 5 shows four radial distribution circuits, designated 68F1, 68F2, 68F3 and 68F4, which serve the towns of Charlestown, Richmond, South Kingstown, and ties to Westerly, R.I. These circuits are connected by normally open switches at several locations. These tie points are usually manually operated and may be used to restore service to customers in the event of an outage or to perform maintenance on equipment.

Type II circuits are also radial, but may occasionally have more than one source into the distribution system. Attachment 6 (page 1 of 3) is an example where the distribution system is supplied from the transmission system at Kent County #22, Davisville #24 and West Kingston #62 substations. Power would always flow into this system from Kent County, Davisville, and West Kingston; opening the 34 kV circuit ties would have no impact on the transmission system.

(3) Power flows into local distribution systems; it rarely, if ever, flows out.

Power flow is into a local distribution system, and is metered at the transmission/distribution interface. More than one supply point may exist as previously described in item (2) above and shown in Attachment 6, page 1 of 3. Because these systems are radial in nature, the net power flow will be into the system to serve the local load. Pages 2 and 3 of Attachment 6 show the billing metering facilities at West Kingston and Kent County, respectively. Refer to Attachment 18 for a description of symbols and designations used on billing meter layouts.

If generation exists on the distribution system, separate billing metering facilities would be located at the local generation facility to segregate wholesale services from local distribution deliveries. Attachments 7 and 8 show examples where a wholesale transaction from generation resides on a 23 kV distribution facility which also provides service to retail customers. In Attachment 8, Pawtucket Power Associates generation facility resides on a 23 kV distribution facility in Rhode Island.

(4) ***When power enters a local distribution system, it is not reconsigned or transported on to some other market.***

Narragansett's distribution system serves retail end-use customers. In cases where distribution facilities are also used to serve wholesale customers, that portion of the cost of those facilities used for wholesale services would be assigned to the wholesale transaction. Separate metering is located at the wholesale customer to segregate wholesale deliveries from local distribution deliveries. There are instances of such wholesale deliveries in the NEES system. However, there are no examples currently in Rhode Island. Attachment 9, page 1, shows an example in Massachusetts where the wholesale customer, Merrimac Municipal, is served from the 2377 line; a 23 kV distribution facility. The 2377 line also serves retail end-use customers in the Amesbury/Salisbury area. Metering facilities for Merrimac Municipal are shown in Attachment 9, page 2. The cost of the portion of those facilities used to serve Merrimac Municipal is assigned to the wholesale transaction. This would be the same in Rhode Island if Narragansett Electric had a wholesale customer.

Attachment 10, shows an example where one NEES retail company, Massachusetts Electric, is supplying Narragansett from 23 kV facilities. The Massachusetts Electric facilities are at Mink Street. Attachment 10 shows the metering on the 2267 circuit which serves Narragansett's Waterman Ave. Substation and provides back-up for Kent's Corner and East Providence distribution substations in Rhode Island. In this case, the cost of the portion of the facilities used for wholesale services to Narragansett is assigned to the wholesale transaction.

(5) ***Power entering a local distribution system is consumed in a comparatively restricted geographical area.***

Narragansett's distribution system serves load in a comparatively restricted geographical area. The geographical area served by a local distribution system depends on the load density of the area. For example, several Type I or Type II distribution circuits as shown in Attachment 1 may serve a large city or a number of rural towns.

Attachment 11, shows the area map and Attachment 12 the electrical one line diagram for four distribution feeders which serve the towns of Tiverton and Little Compton. This represents how a typical Type I distribution system serves a restricted geographic area.

Attachment 4, page 1, shows the electrical one line diagram for the Type II distribution system served from the Wood River No. 85 Substation. The three distribution circuits 85T1, 85T2 and 85T3 serve the limited geographic area shown on Attachment 4, page 2.

Attachment 13 shows an example of where the distribution system is supplied from the transmission system at Drumrock Substation. In this example, both Type I and Type II distribution systems are being served from one transmission /distribution interface. The Type I distribution system is a 12.47 kV system serving a restricted geographic area. The Type II distribution system is a 23 kV system serving a completely separate geographic area than the Type I 12.47 kV system.

(6) Meters are based at the transmission/distribution interface to measure flows into the local distribution system.

Metering to measure flows into Narragansett's distribution system is based at the transmission/distribution interface, typically on the low voltage side of the stepdown transformer.

Attachment 6, pages 2 and 3, show billing metering installations at West Kingston and Kent County substations from the 115 kV system. Attachment 14 shows similar billing metering at the West Cranston No. 21 substation on the 12.47 kV side of the 115/13.2 kV transformers supplied from the 115 kV transmission lines designated S171 and T172. Attachment 15 shows the billing metering at the Wood River No. 85 Substation for the distribution system shown schematically in Attachment 4, Page 1, on the 34.5 kV side of the 115/34.5 kV transformers supplied from the 115 kV transmission lines designated 1870S and 1870N.

(7) Local distribution systems will be of reduced voltage.

The local distribution voltages of the NEES retail companies are less than 69 kV. Typical voltage classes used are 5, 15, 25 and 35 kV. Attachment 16 shows the actual distribution voltages and the letter designations used by the NEES retail companies to identify Type I distribution. Type II distribution circuit voltages are 12.47, 23 or 34.5 kV. Narragansett has no distribution voltage above 34.5 kV.

V. Description of the NEES Transmission System

The function of transmission facilities is to integrate generation resources over large geographical areas and deliver the needed power to local distribution supply systems. The NEES transmission system is used to transmit power from generation resources located on its system or on the transmission systems of other utilities to the loads served by the distribution system. By definition, a transmission system is always interconnected to the neighboring transmission systems of neighboring utilities. Transmission lines are rarely, if ever, directly connected to retail customers, and with few a exceptions, the NEES companies transmission system is a 69 kV or greater class system.

On Narragansett's transmission system in Rhode Island, there is no transmission below 115 kV.[5] However, there are two instances outside of Rhode Island where the NEP transmission system is of lower voltage. First, if a lower voltage system is used to integrate generation resources and interconnected utilities, as it does at 34.5 kV in the Comerford/Moore area shown in Attachment 17, this is defined as transmission. Second, if a low voltage system is used to interconnect two utilities as does the 34.5 kV system in the Comerford/Moore area and the 46 kV system in the Bellows Fall/Charlestown area (Attachment 18), this is also defined as transmission.

[5] Two limited exceptions relate to Narragansett ownership of two 23 kV transmission interconnections that allow Pawtucket Power and the Johnston Landfill IPP projects to sell power from their facilities at wholesale.

VI. Conclusion

Narragansett's facilities are unbundled on a functional basis between FERC jurisdictional transmission and state jurisdictional local distribution. Based on the application of the seven factors identified by FERC, Narragansett and the NEES Companies conclude that they are structured according to FERC's definition of transmission and local distribution facilities. The distribution facilities of Narragansett and the other NEES Companies subject to state rate making jurisdiction today fit the seven-part test established by FERC for the definition of local distribution facilities used for retail access in a restructured industry. In addition, NEP, as the generation and transmission provider, fits the FERC definition of transmission based on its customers, voltage class, and system type.

VII. Attachments

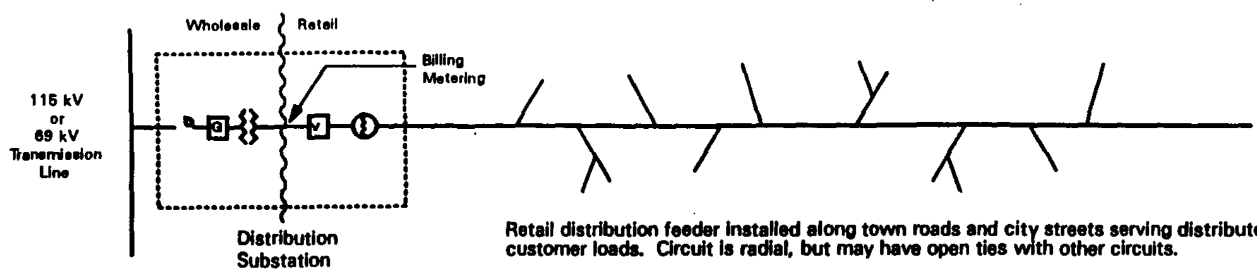
Attachment 1	Diagram of Type I and Type II Distribution Systems
Attachment 2	List of Narragansett's transmission/distribution supply points
Attachment 3	Town Map of Charlestown, Richmond and, South Kingston showing distribution lines on streets
Attachment 4 (2 pages)	Wood River Substation one line diagram (PLND-3401-0) and geographic map
Attachment 5	Feeder Tie Map of Kenyon for the towns Charlestown, Richmond, South Kingston, and Westerly
Attachment 6	
Page 1 of 3	Distribution System served from Kent County, Davisville, and West Kingston (PLND-3402-0)
Page 2 of 3	West Kingston Billing Metering Layout (B533)
Page 3 of 3	Kent County Billing Metering Layout (B534)
Attachment 7	Admiral Street Billing Meter Layout (B539)
Attachment 8	Pawtucket Power (B548)
Attachment 9	
Page 1 of 2	King Street #18 one line diagram (LND-2365-0)
Page 2 of 2	Memman Municipal Billing Meter Layout (B410)
Attachment 10	Mink Street Billing Meter Layout (B509)
Attachment 11	Geographic map and feeder tie map for Tiverton area
Attachment 12	Tiverton one line diagram
Attachment 13	Drumrock Billing Meter Layout (B530)
Attachment 14	West Cranston Billing Meter Layout (B535)

Exhibit A -- Page 15

Attachment 15	Wood River Billing Meter Layout (B544)
Attachment 16	Numbering Distribution - Feeder Std. 8151
Attachment 17	Comerford 34.5 kV Area
Attachment 18	Bellows Falls/Charlestown 46 kV Area
Attachment 19	Billing Metering Layout Symbols B1, B2

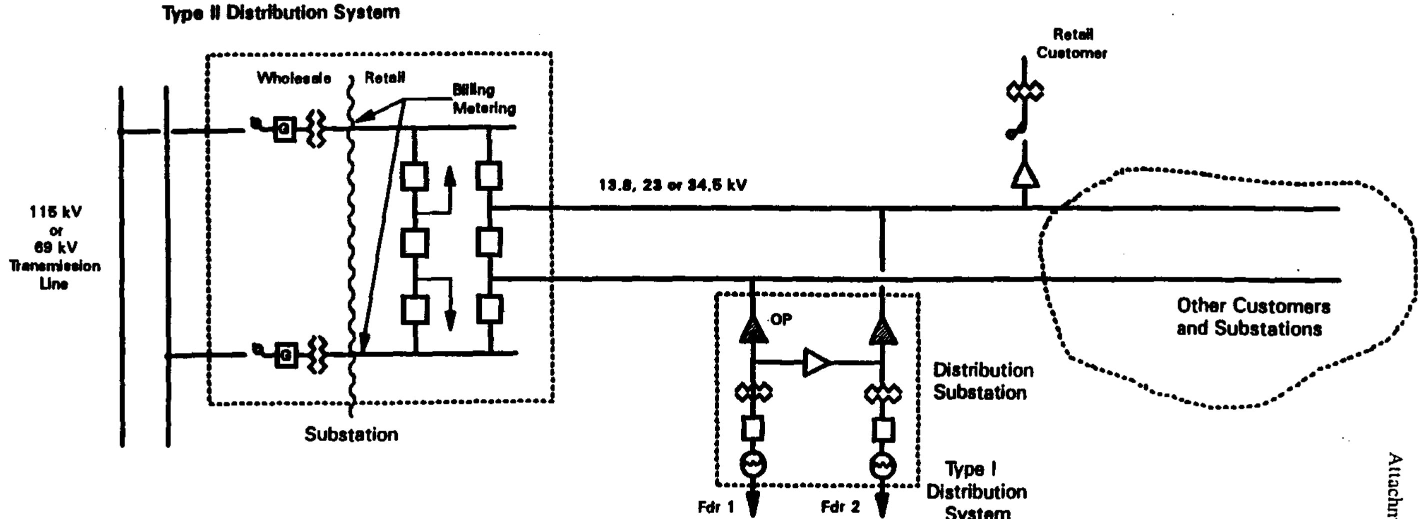
TYPICAL LOCAL DISTRIBUTION SYSTEMS
VOLTAGE CLASS: 5, 15, 25, 34.5 kV

Type I Distribution System



Retail distribution feeder installed along town roads and city streets serving distributed customer loads. Circuit is radial, but may have open ties with other circuits.

Type II Distribution System



A typical type II distribution system will emanate from a transmission supplied substation, will be built along right-of-way and streets, will provide distribution supply service to substations serving type I distribution systems and, often times, to larger commercial/industrial customers.

Attachment I

THE NARRAGANSETT ELECTRIC COMPANY

Name of District	Distribution System Type	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments
Main District:						
Admiral Street Substation (9)	II	115	SDP	23	SDP	SL
Bristol Substation (51)	I	115	SDP	12.47	SDP	SL
Clarkson Street Substation (13)	I	115	SDP	12.47	SDP	SL
Davisville Substation (84)	II	115	SDP	34.5	SDP	SL
Drumrock Substation (14)	I, II	115	SDP	23/12.47	SDP	SL
Farnum Pike Substation (23)	I	115	SDP	12.47	SDP	SL
Franklin Square Substation	I, II	115	SDP	11.5	SDP	SL
Johnston Landfill (Northeast)	Wholesale	23	SDP	23	SDP	SL
Johnston Substation (18)	I, II	115	SDP	23/12.47	SDP	SL
Kent County Substation (22)	II	115	SDP	34.5	SDP	SL

SDP Standard Delivery Point
SL Supply Line

Name of District	Distribution System Type	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments
Kenyon Stustation (68)	I	115	SDP	12.47	SDP	SL
Lincoln Substation (72)	I	115	SDP	12.47	SDP	SL
Manchester Street Generation Station (Franklin Square Substation)	Wholesale	11.5	SDP	11.5	SL	SL
Mink Street Substation (7)	II	23	SDP	23	SDP	SDP
Old Baptist Road Substation (46)	I	115	SDP	12.47	SDP	SL
Pawtucket Power	Wholesale	23	Patucket/ Providence City Line	23	SDP	SL
Phillipsdale Substation (20)	II	115	SL	115	SL	SL
Pontiac Substation (27)	II	115	SDP	12.47	SDP	SL
Sockanosset Substation (24)	II	115	SDP	23	SDP	SL
South Street Station	I, II	115	SDP	11.5	SDP	SL
Wampanoag	I	115	SDP	12.47	SDP	SL

SDP Standard Delivery Point
SL Supply Line

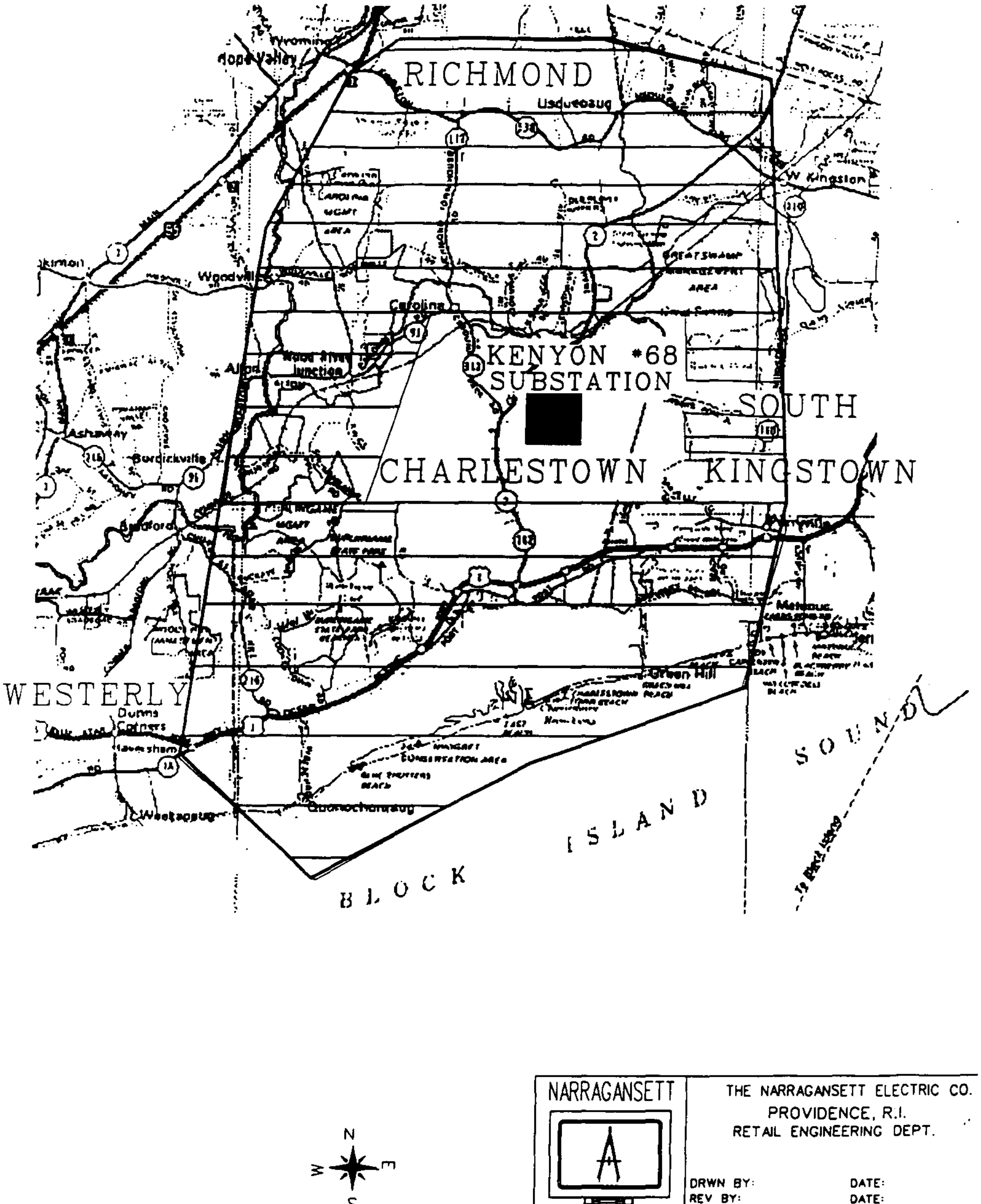
ATTACHMENT 2
Page 3

Name of District	Distribution System Type	Delivery Pressure KV (Nominal)	Metering Points	Metering Pressure KV (Nominal)	Metering Adjustments	Delivery Adjustments
Warren Substation (5)	I, II	115	SDP	23/12/47	SDP	SL
West Cranston Substation (21)	I	115	SDP	12.47	SDP	SL
West Kingston Substation (62)	II	115	SDP	34.5	SDP	SL
Wolf Hill Substation (19)	II	115	SDP	23	SDP	SL
Wood River Substation (85)	I, II	115	SDP	34.5	SDP	SL
Tiverton District:						
Tiverton Substation (33)	I	115	SL	12.47	SL	SL

SDP Standard Delivery Point
SL Supply Line

Attachment 3

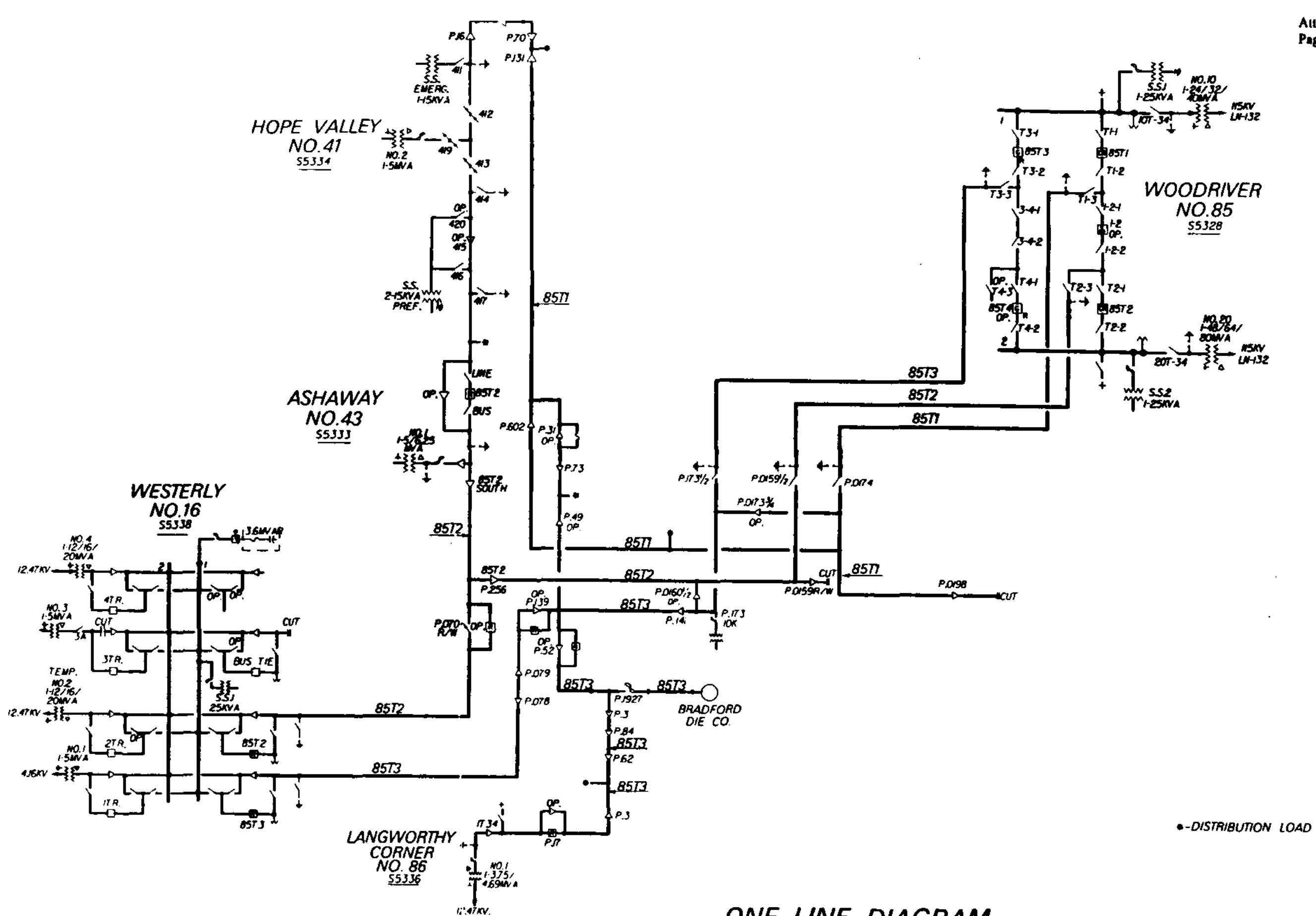
Kenyon #68 Area Map



NARRAGANSETT
THE NARRAGANSETT ELECTRIC CO.
PROVIDENCE, R.I.
RETAIL ENGINEERING DEPT.

DRWN BY:
REV BY:
PROJECT NO.
DATE:
DATE:
FILENAME:

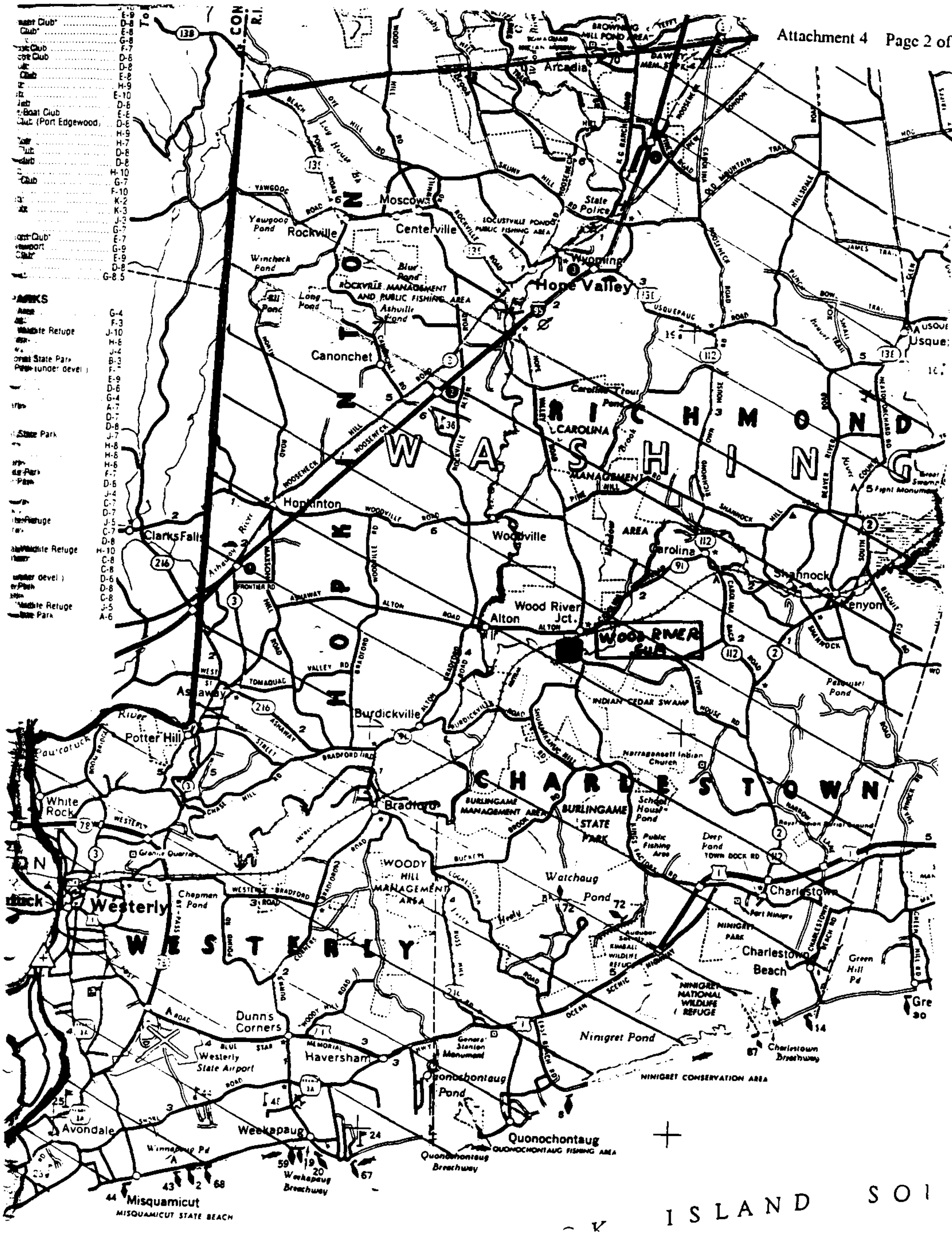
Attachment 4
Page 1 of 2



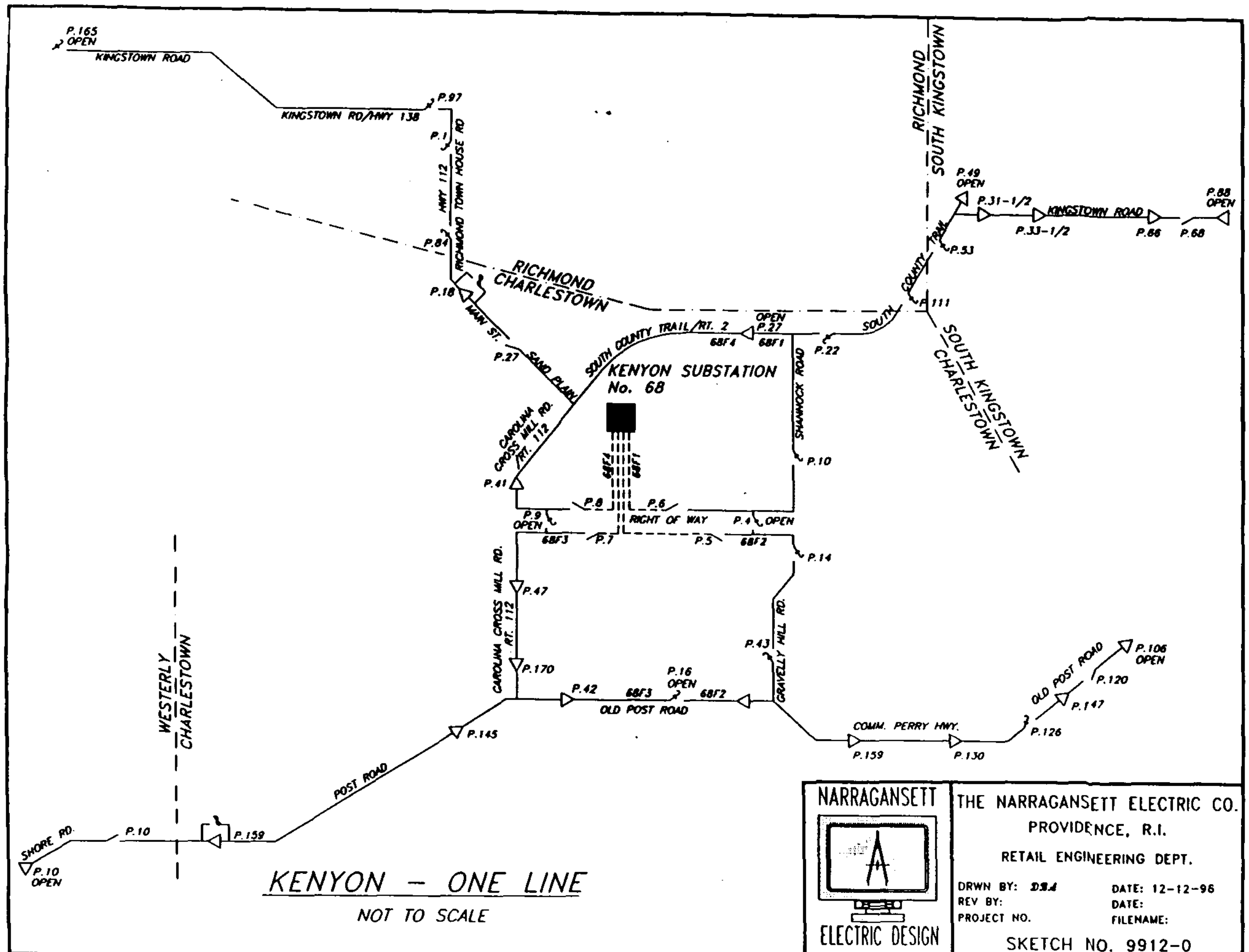
ONE LINE DIAGRAM
34.5KV LINES: 85T1, 85T2, 85T3.
NARRAGANSETT ELECTRIC COMPANY

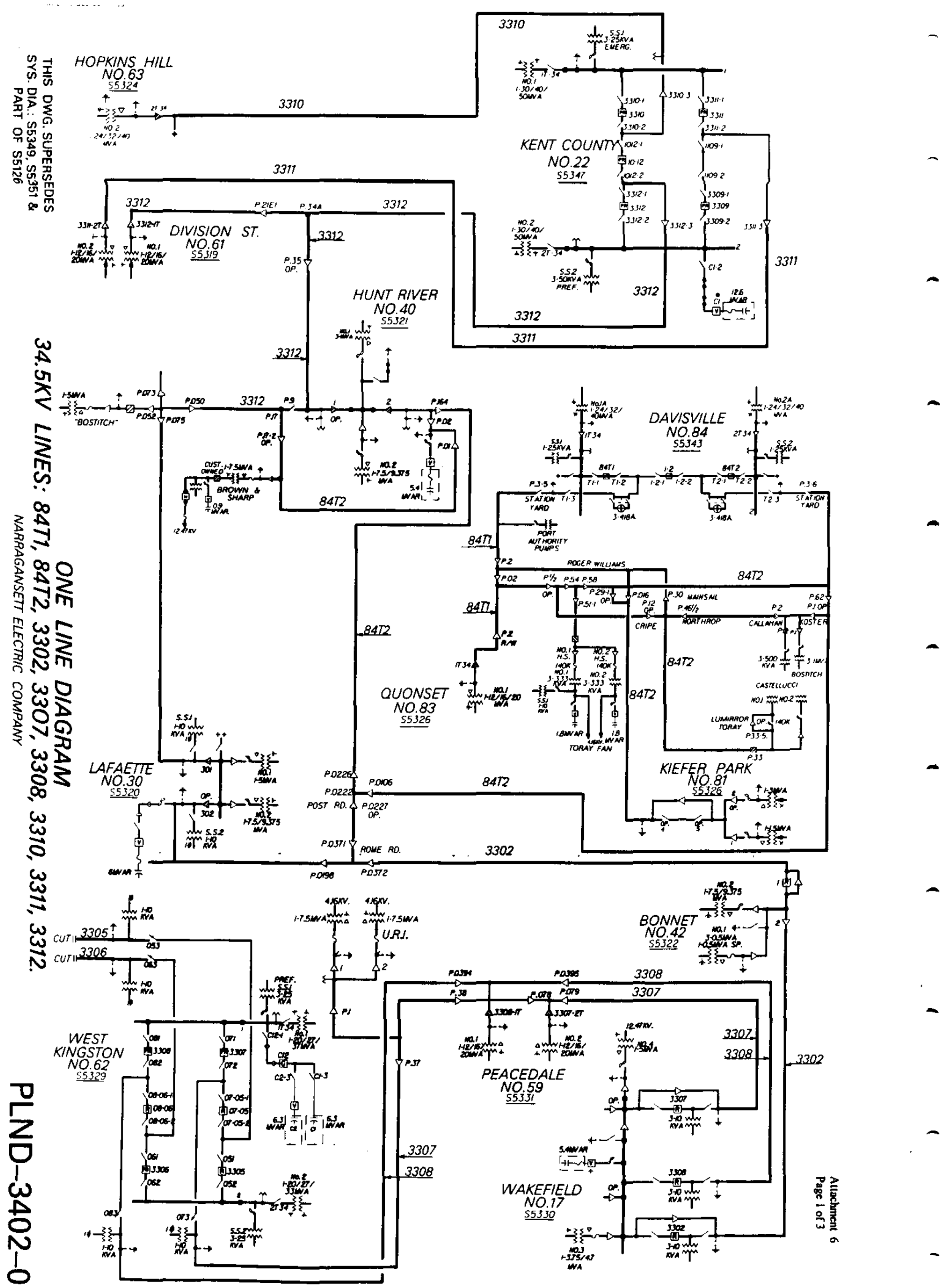
PLND-3401-0

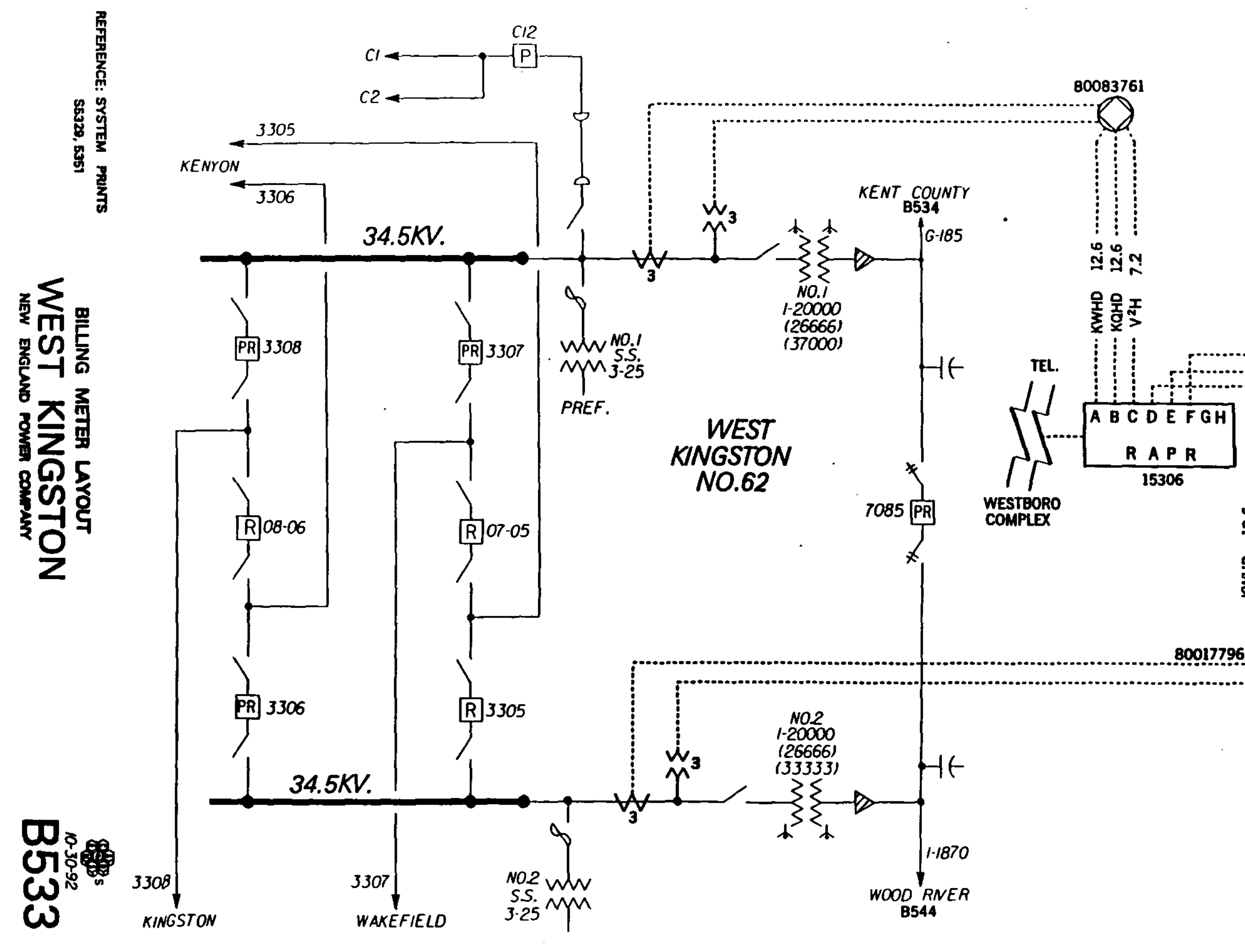
Attachment 4 Page 2 of 2



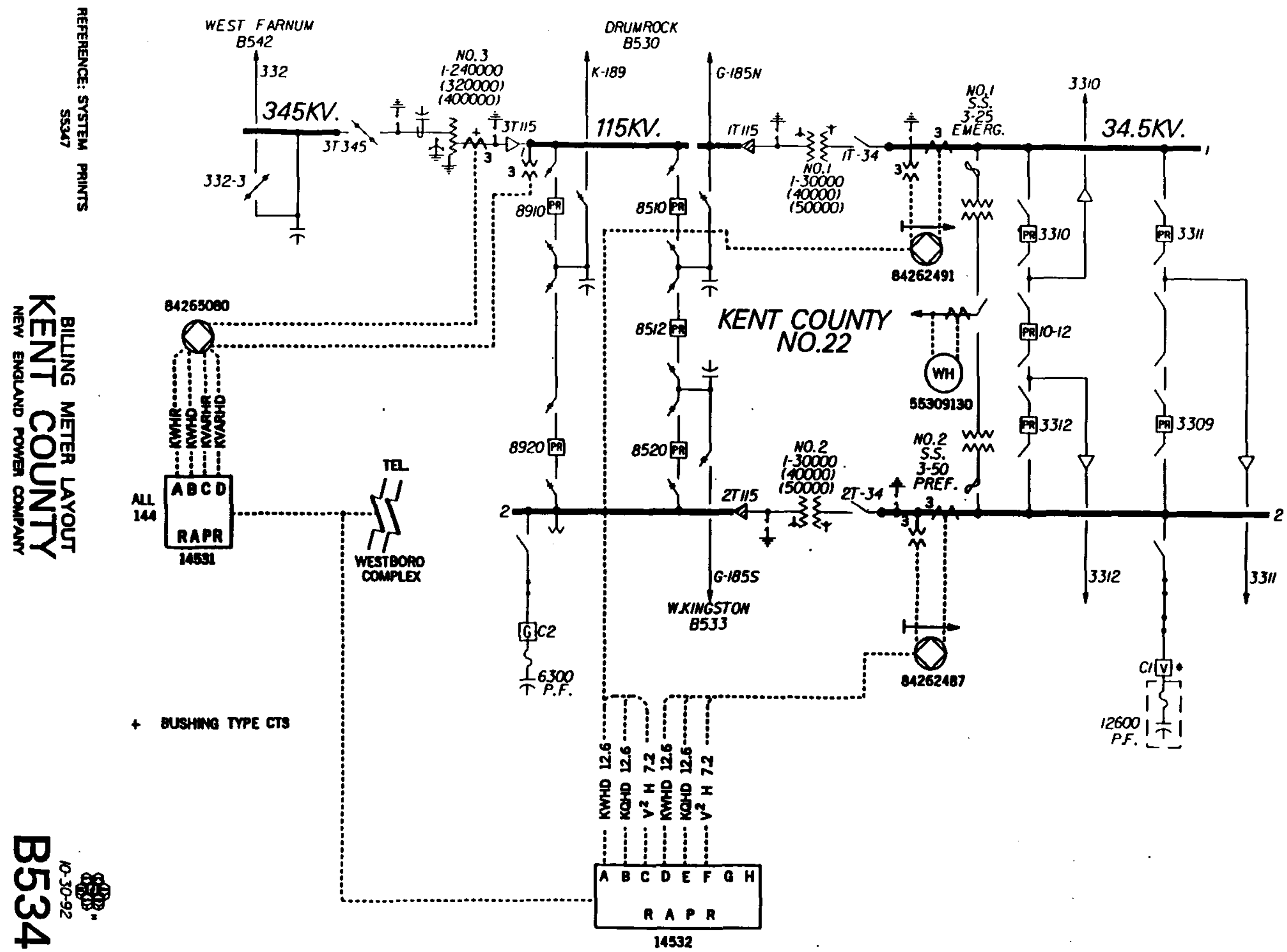
Attachment 5




ONE LINE DIAGRAM
34.5KV LINES: 84T1, 84T2, 3302, 3307, 3308, 3310, 3311, 3312.
NARRAGANSETT ELECTRIC COMPANY
THIS DWG. SUPERSEDES SYS. DIA.: S5349, S5351 & PART OF S5126
PLND-3402-0
HOPKINS HILL NO.63 S5324
KENT COUNTY NO.22 S5347
DIVISION ST. NO.61 S5319
HUNT RIVER NO.40 S5321
DAVISVILLE NO.84 S5343
QUONSET NO.83 S5326
KIEFER PARK NO.81 S5326
LAFAETTE NO.30 S5320
BONNET NO.42 S5322
WEST KINGSTON NO.62 S5329
PEACEDALE NO.59 S5331
WAKEFIELD NO.17 S5330
Attachment 6
Page 1 of 3

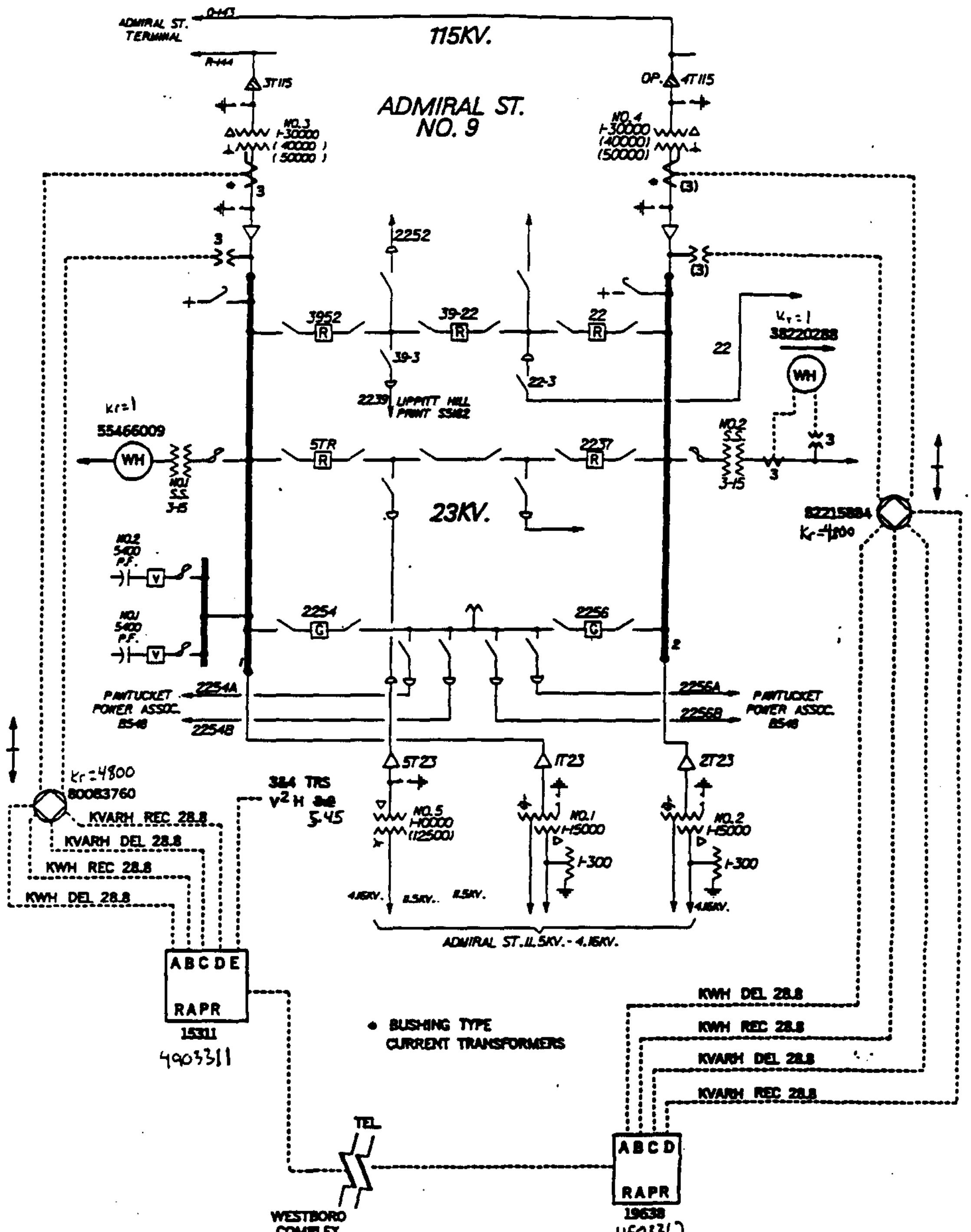


Attachment 6
Page 2 of 3



Attachment 6
Page 3 of 3

Attachment 7

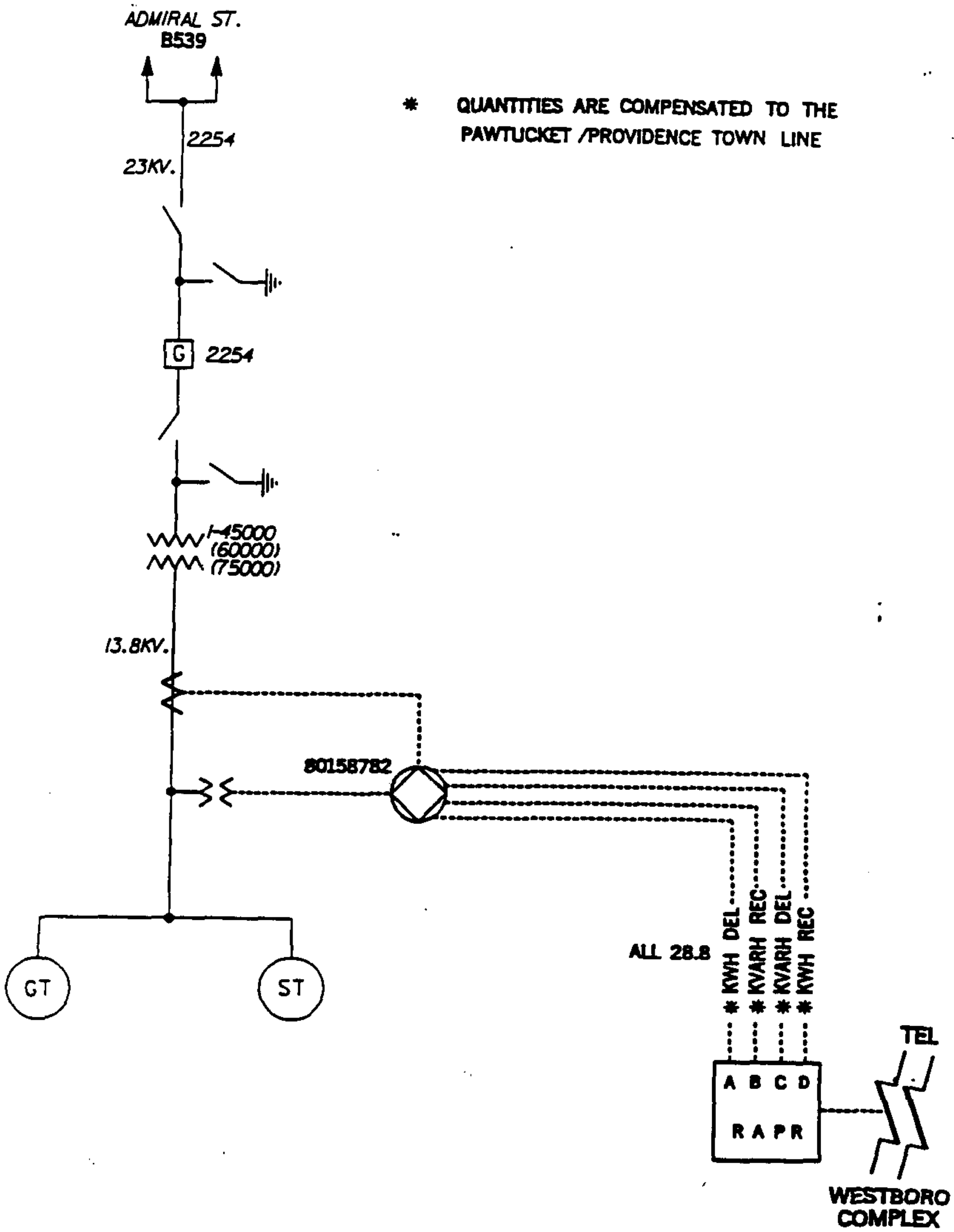


REFERENCE: SYSTEM PRINTS S5201

BILLING METER LAYOUT
ADMIRAL ST.
NEW ENGLAND POWER COMPANY

10-30-92
B539

Attachment 8



REFERENCE: SYSTEM PRINTS
S5203

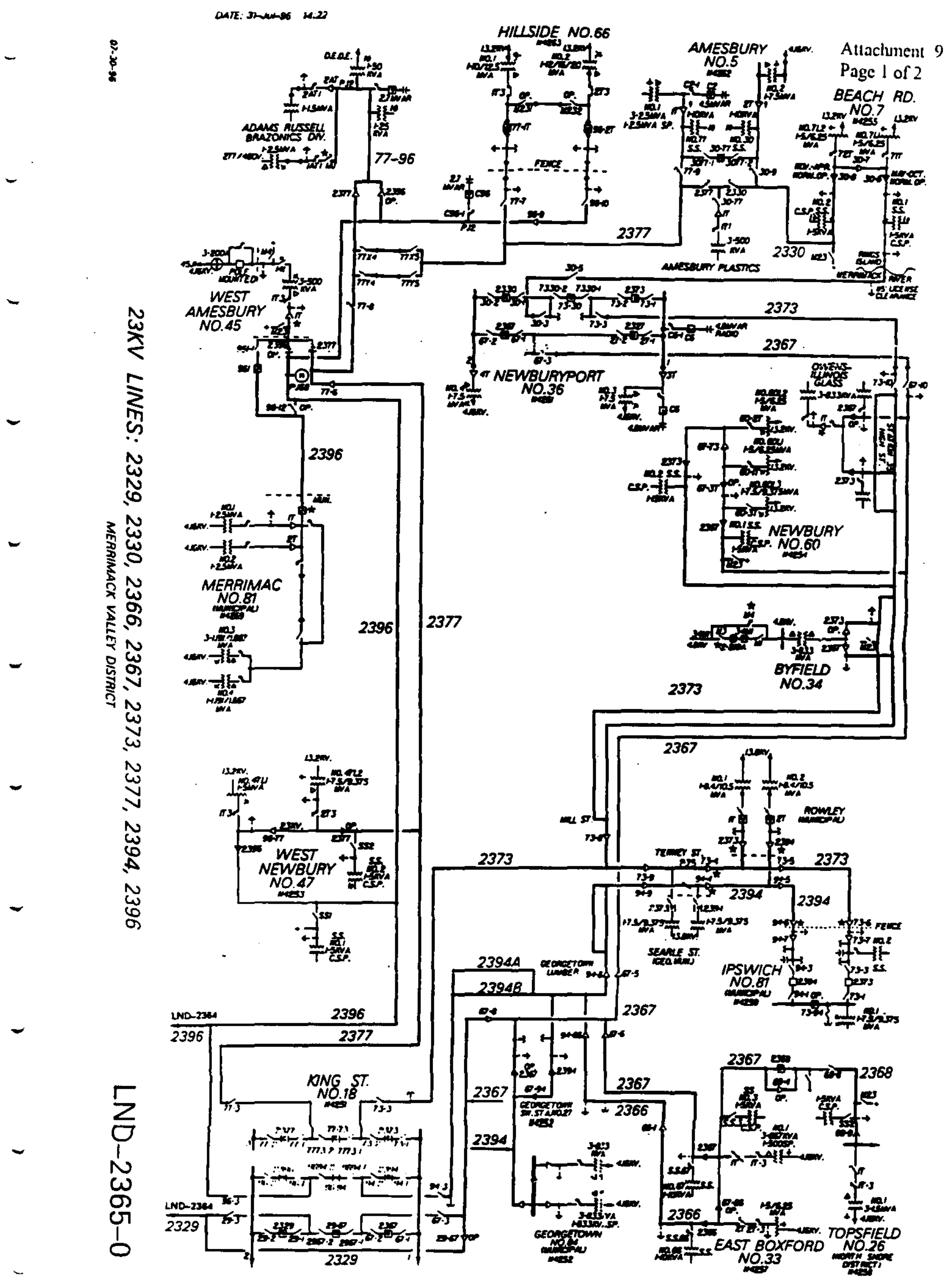
BILLING METER LAYOUT

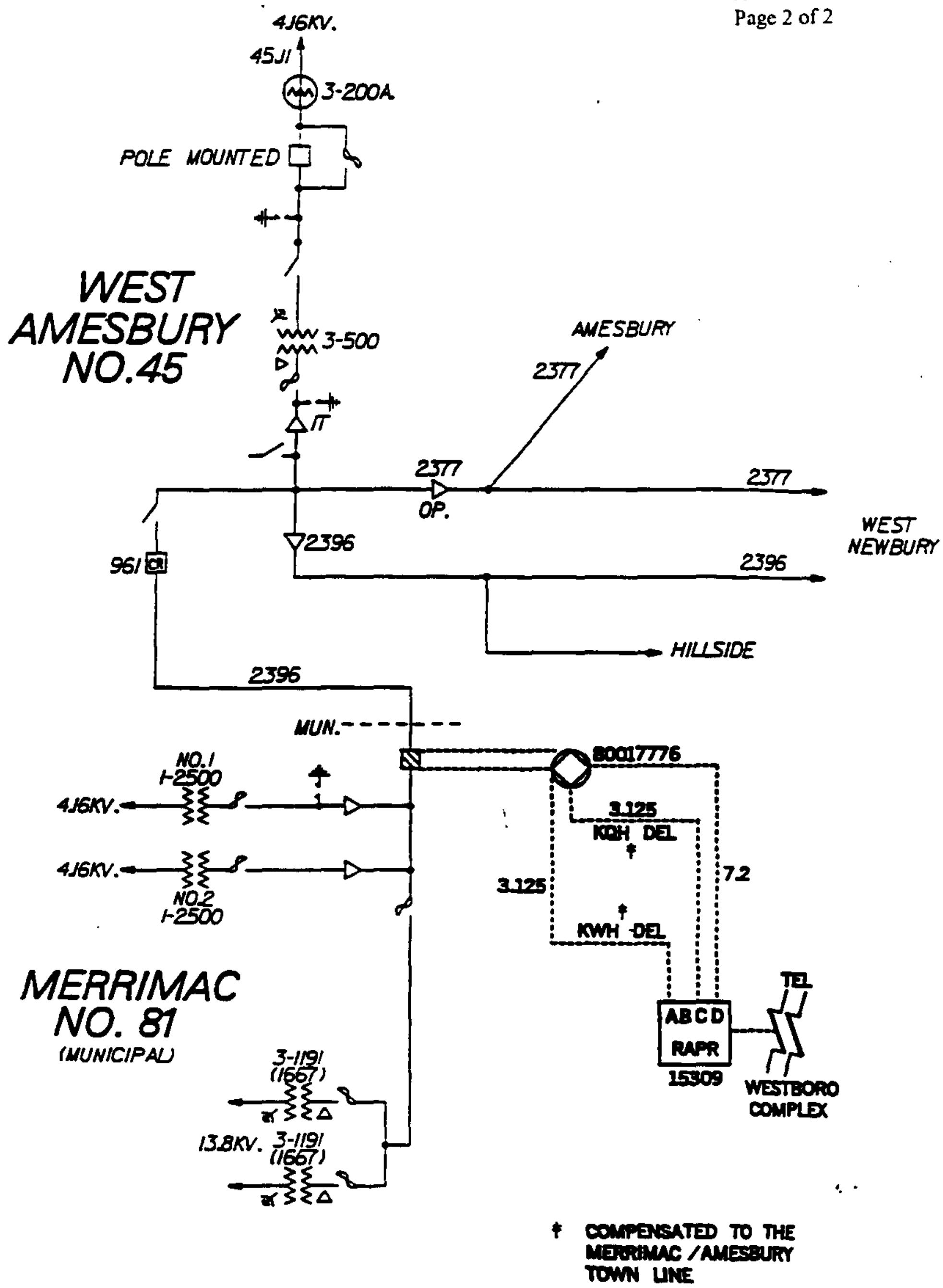
PAWT.POWER ASSOC. (COLFAX)

NEW ENGLAND POWER COMPANY

10-30-92

B548


Attachment 9
Page 1 of 2
23KV LINES: 2329, 2330, 2366, 2367, 2373, 2377, 2394, 2396
MERRIMACK VALLEY DISTRICT
LND-2365-0
HILLSIDE NO.66
AMESBURY NO.5
BEACH RD. NO.7
ADAMS RUSSELL BRAZONICS DIV.
WEST AMESBURY NO.45
AMESBURY PLASTICS
NEWBURYPORT NO.36
OWENS-ILLINOIS GLASS
NEWBURY NO.60
MERRIMAC NO.81
BYFIELD NO.34
ROWLEY
WEST NEWBURY NO.47
SEARLE ST.
IPSWICH NO.81
KING ST. NO.18
GEORGETOWN NO.84
EAST BOXFORD NO.33
TOPSFIELD NO.26
2377
2330
2373
2367
2396
2394
2394A
2394B
2366
2368
2329
LND-2364

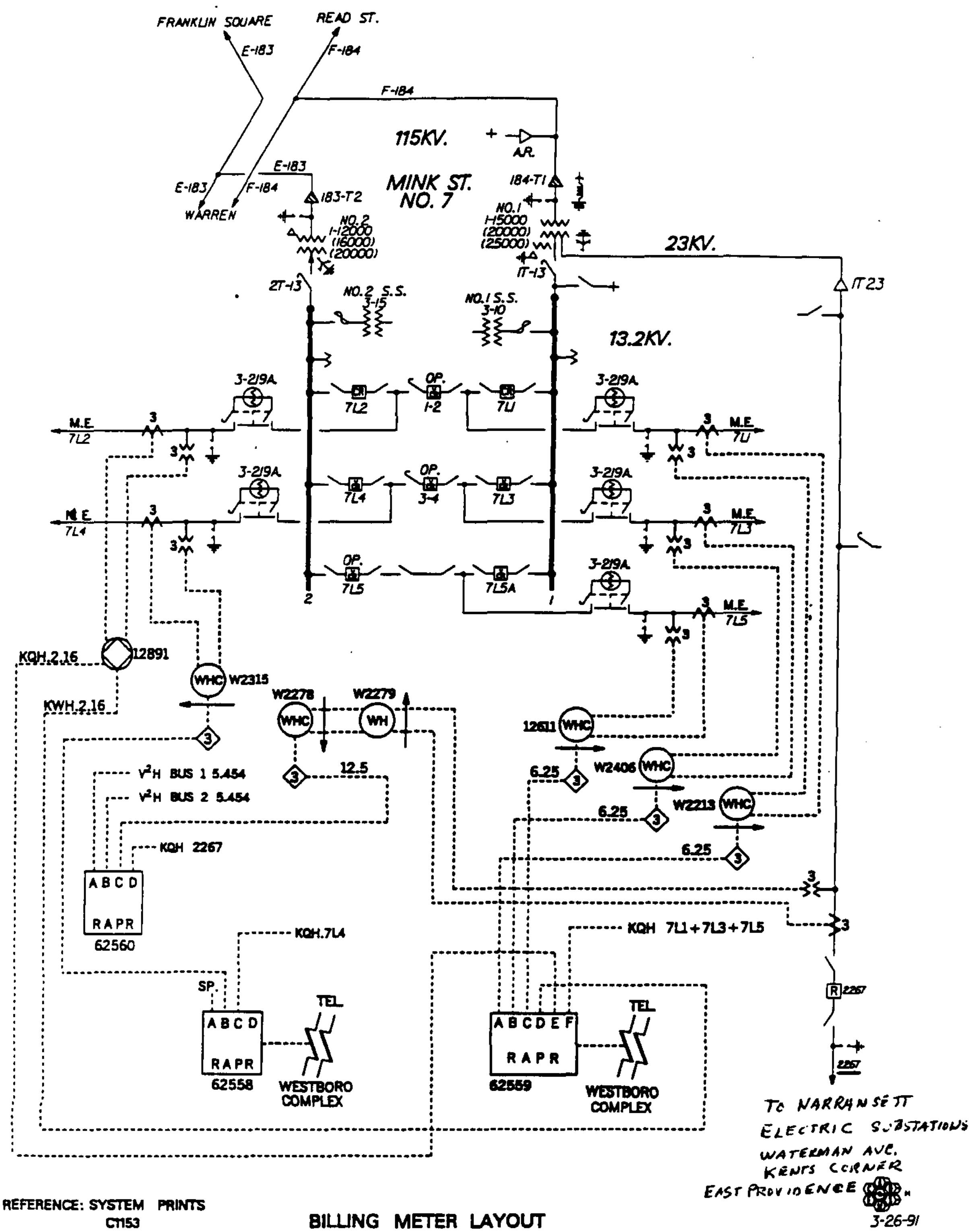


REFERENCE: SYSTEM PRINTS N4284,N4288

BILLING METER LAYOUT
MERRIMAC (MUNICIPAL)
NEW ENGLAND POWER COMPANY

12-15-90
B410

Attachment 10



REFERENCE: SYSTEM PRINTS
C1153

BILLING METER LAYOUT

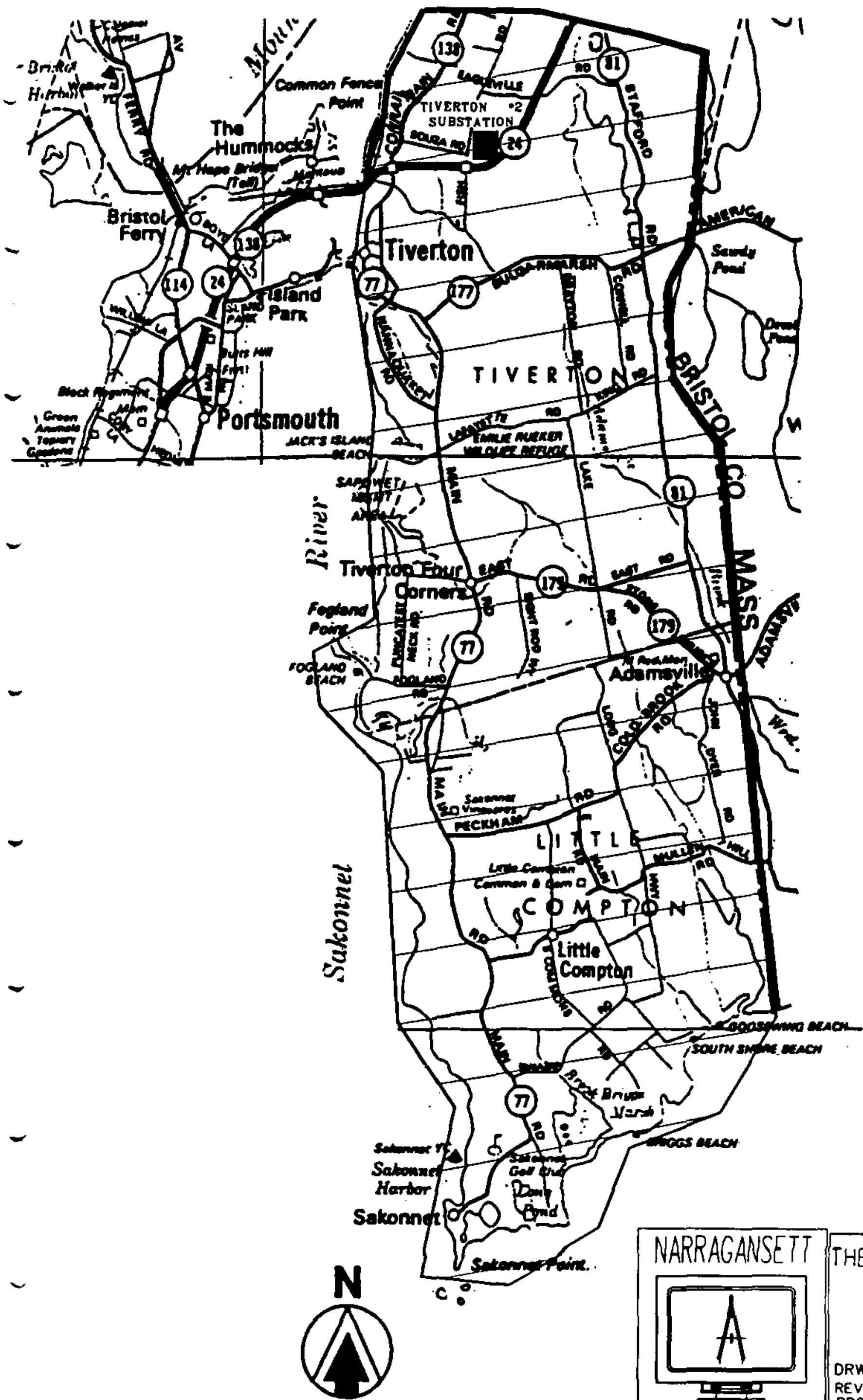
MINK ST.

NEW ENGLAND POWER COMPANY

B509

Attachment 11

Tiverton *2 Area Map
Tiverton and Little Compton



NARRAGANSETT

ELECTRIC DESIGN

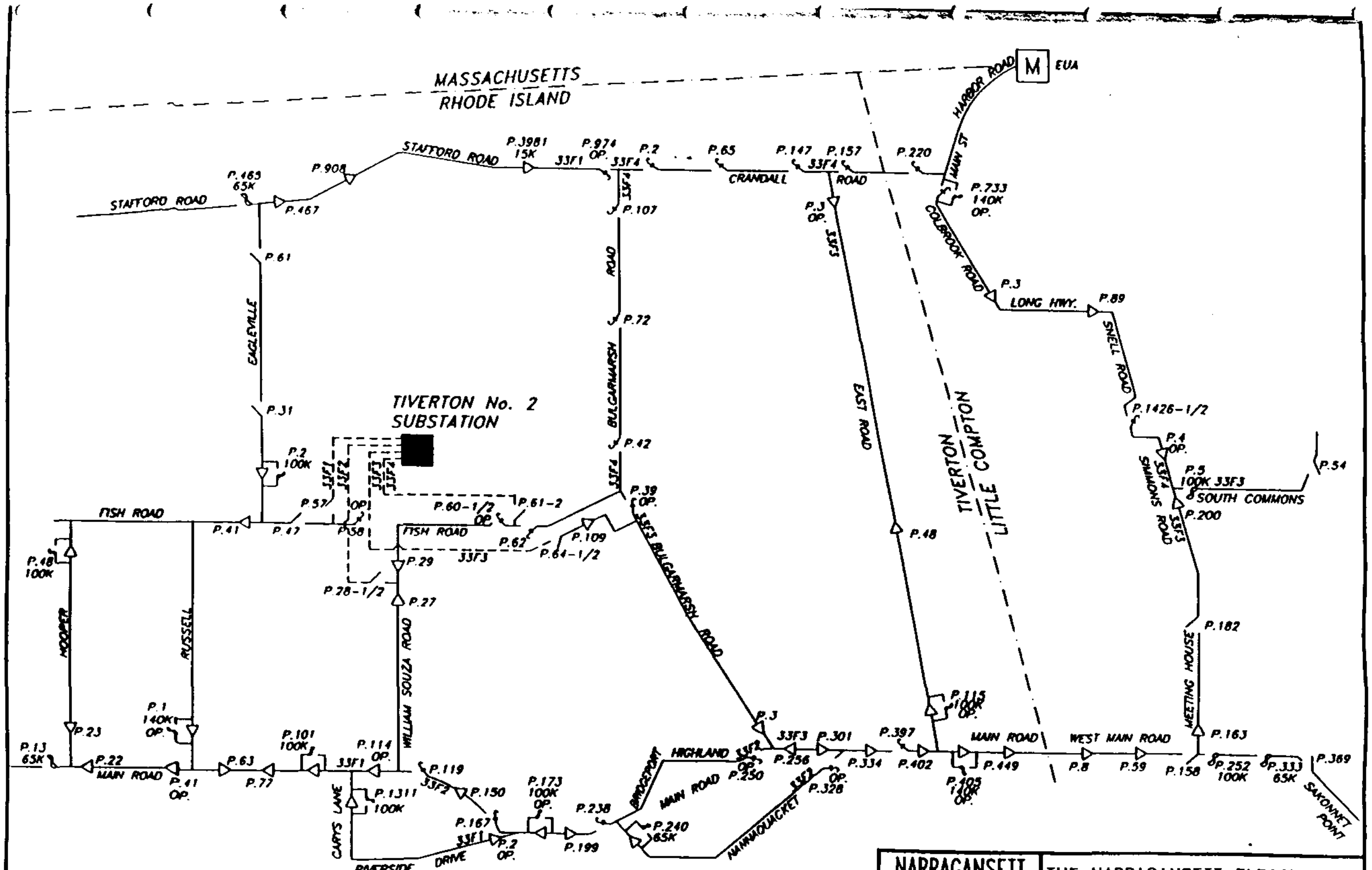
THE NARRAGANSETT ELECTRIC CO

PROVIDENCE, R.I.

RETAIL ENGINEERING DEPT.

DRWN BY: DATE:
REV BY: DATE:
PROJECT NO. FILENAME:

SKETCH NO.



THE NARRAGANSETT ELECTRIC CO.
PROVIDENCE, R.I.
RETAIL ENGINEERING DEPT.

DRWN BY: DSA — DATE: 12-12-96
REV BY: — DATE:
PROJECT NO. — FILENAME:

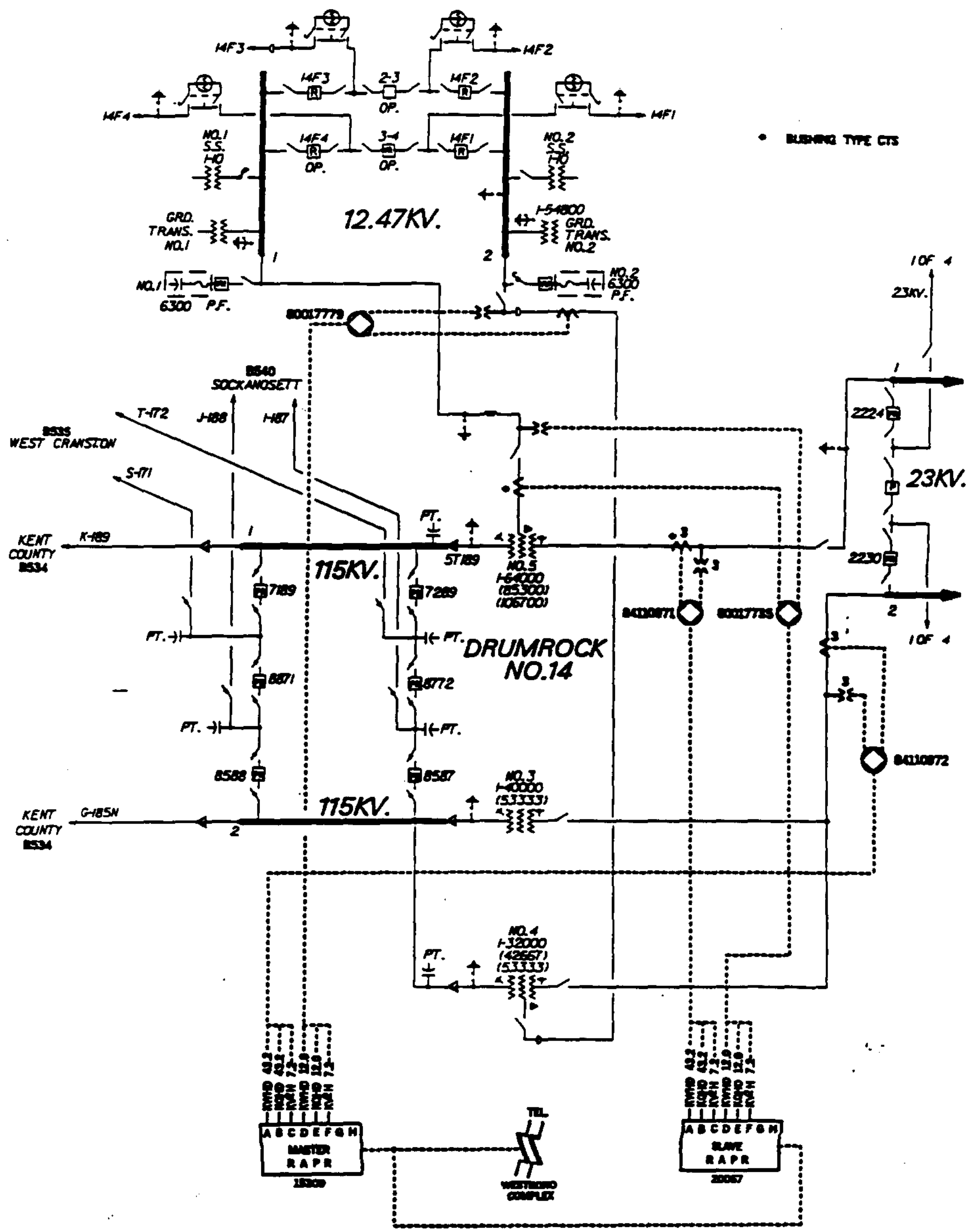
SKETCH NO. 9911-0

TIVERTON – ONE LINE

NOT TO SCALE

Attachment 12

Attachment 13

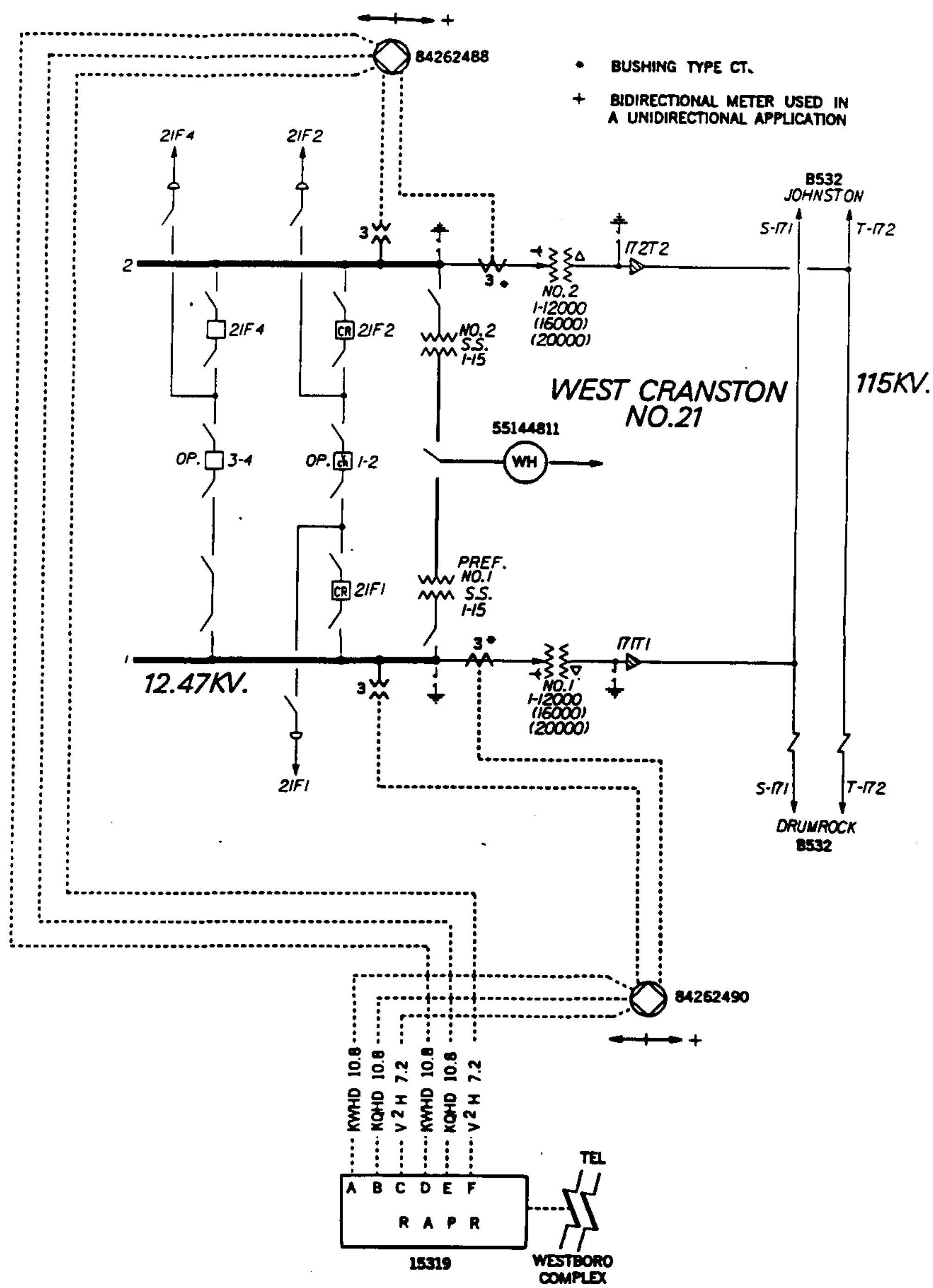


REFERENCE: SYSTEM PRINTS S6283

BILLING METER LAYOUT
DRUMROCK
NEW ENGLAND POWER COMPANY

10-30-92
B530

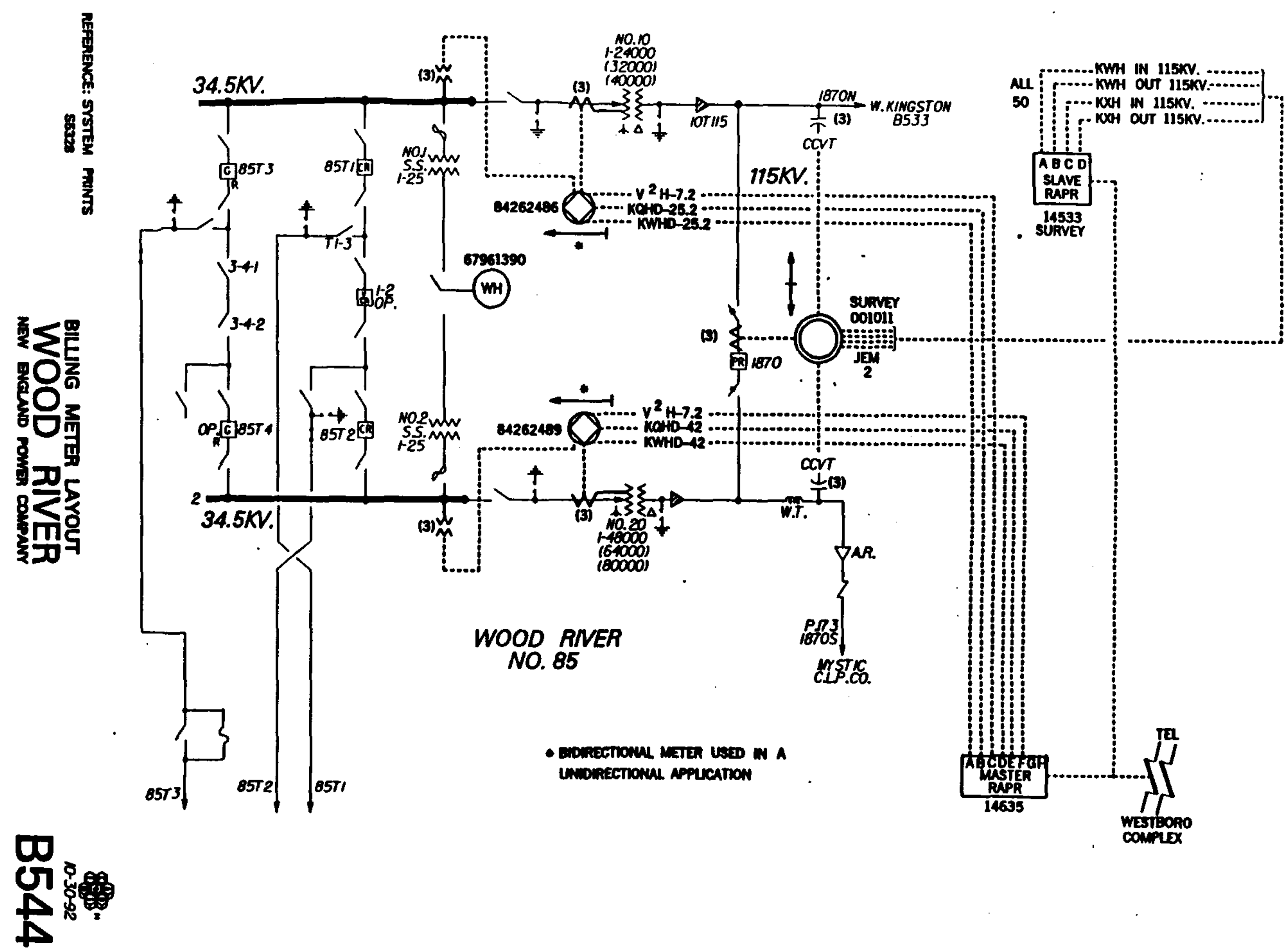
Attachment 14



REFERENCE: SYSTEM PRINTS
S5386

BILLING METER LAYOUT
WEST CRANSTON
NEW ENGLAND POWER COMPANY

10-30-92
B535



Attachment 15

Attachment 16

New England Electric

NUMBERING DISTRIBUTION FEEDERS and Street Light Circuits

STD 8151

D Issue

1. APPLICATION - The distribution and Dispatching Departments of each company shall assign numbers in accordance with this STANDARD.

Transmission and distribution supply lines are numbered by the System Dispatching Department.

2. ALL STATIONS & SUBSTATIONS are to be numbered consecutively - 1, 2, 3, etc.

3. CLASSIFICATION LETTERS for feeders and circuits are;

R - Series Street Lighting Circuits
DC - Direct Current Circuits
H - 2400 V Distribution Feeders
J - 4160 V " "
M - 4800 V " "
G - 8320 V " "
F - 12470 V " "
L - 13200 V " "
W - 13800 V " "
K - 24900 V " "
T - 34500 V " "

4. FEEDERS & CIRCUITS for each substation shall be numbered consecutively - 1, 2, 3, etc.

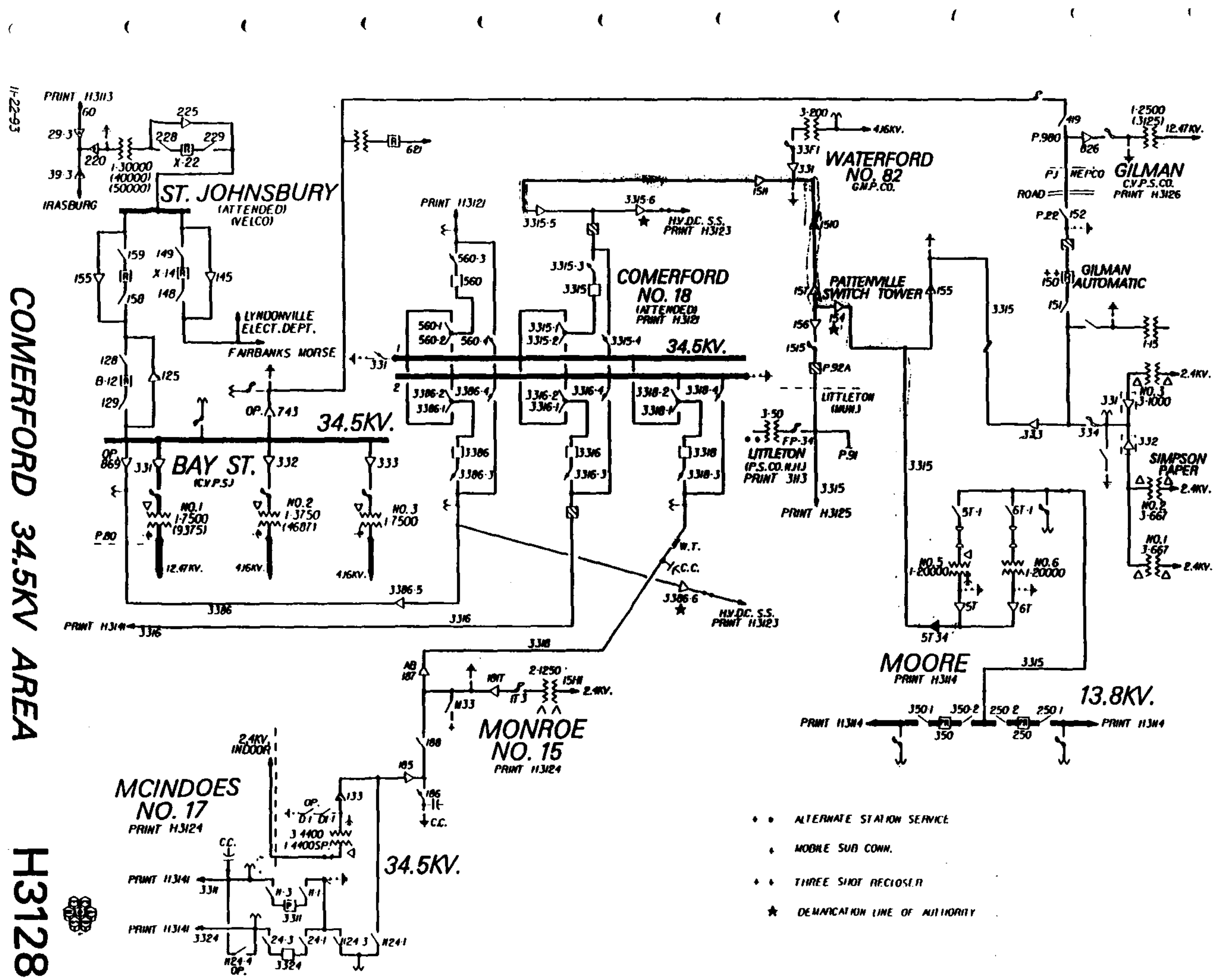
5. DISTRIBUTION FEEDER NUMBER combines the items of the above three paragraphs in sequence - thus, feeder #5H7 is the 7th 2400 V feeder extending from station #5.

6. STREET LIGHT CIRCUITS are numbered in the same manner as distribution feeders.

Modification for circuits not originating in substations

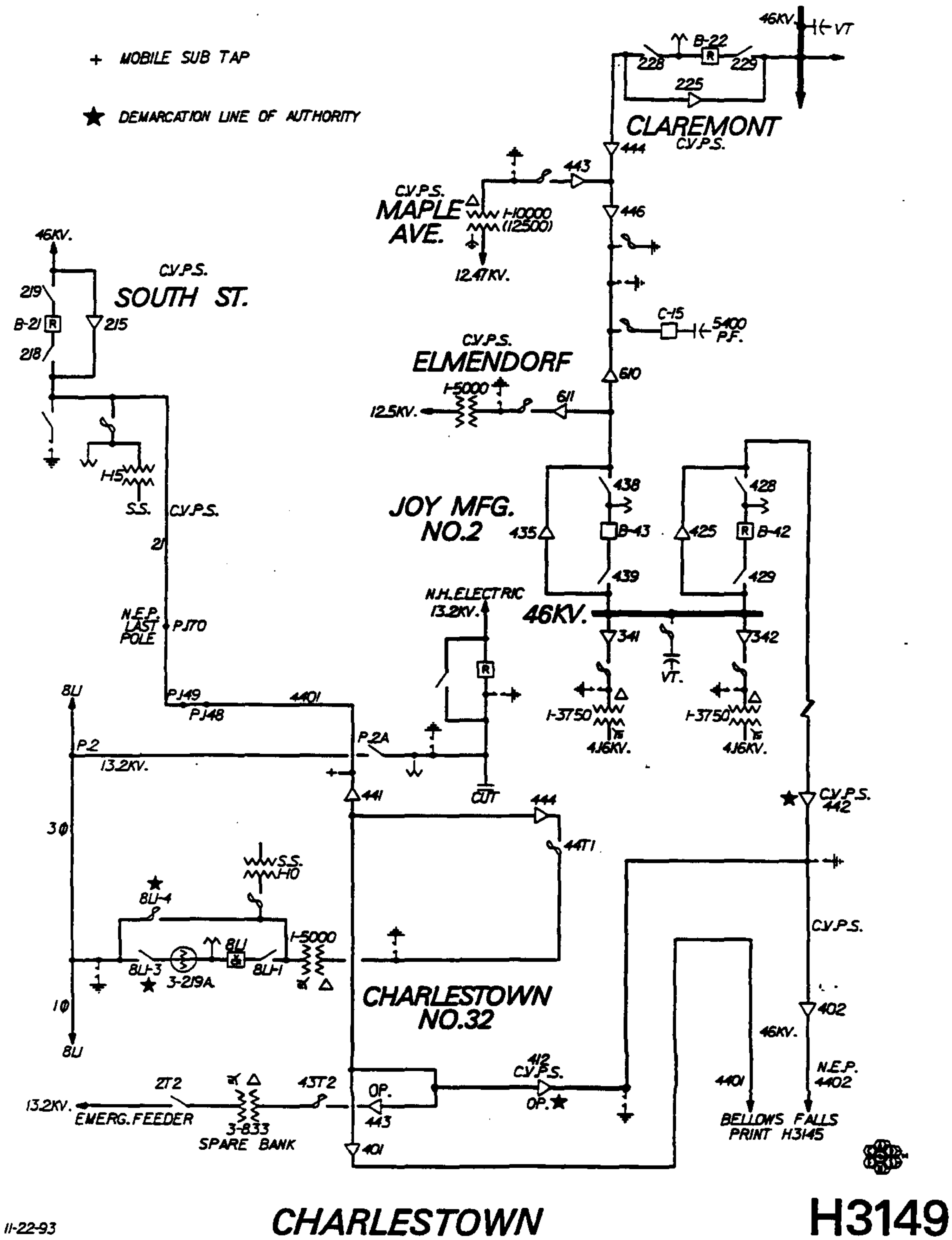
Where a constant current transformer is not located in a substation, the series circuit will carry no prefix for the substation, and the suffix will be consecutive circuit numbers for the entire area - i.e., R1, R2, R3, etc.

Issue D - April 1978 - Parag. 3 - "T" Assigned to 34.5 kV



Attachment 17

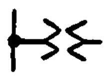
Attachment 18




METERING OUTFIT


CURRENT TRANSFORMER


BUSHING CURRENT TRANSFORMER

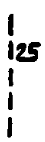

VOLTAGE TRANSFORMER

SURVEY

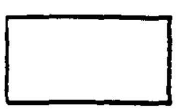

DOUBLE CIRCLE IS USED FOR
SURVEY METERING ONLY


ARROW INDICATES DIRECTION OF
FLOW OF ENERGY IN REFERENCE
TO CURRENT TRANSFORMERS:
BILLING WATTHOUR METER OR INSTRUMENT


SOLID - STATE ELECTRONIC METER



(25KWH PER CONTACT CLOSURE)
METERING CIRCUIT & TELEMETERING


TOTALIZER OR DIGITAL PULSE RECORDER,
MAGNETIC IMPULSE RECORDER OR RAPR
(REMOTE ACCESS PULSE RECORDER)

B1

TYPICAL LETTERS & NUMBERS TO BE INSERTED IN SYMBOLS:

WH = WATTHOUR METER

WHD= WATTHOUR DEMAND METER

VARh= VOLT AMP REACTIVE HOUR METER

WHC= WATTHOUR METER WITH CONTACTS

WHL= WATTHOUR METER WITH LOSS COMPENSATOR

WHCL= WH METER, CONTACTS AND COMPENSATOR

KXH= VARHOUR METER

QHC= QHOUR METER WITH CONTACTS

V^2h= VOLT SQUARED HOUR METER

TYPES OF INSTRUMENTS

SST, DT, MD, CE, PE, WT = IMPULSE TOTALIZING RELAY

FP, L&G, PD, DTR = IMPULSE TYPE PRINTING DEMAND RECORDER

L&G, C14 = SYNCHRONOUS CONTACT CLOCK

TDX = THERMAL DEMAND TRANSMITTER

W456, D456 = COMPANY NUMBER OF METER OR DEVICE

DPR, BPR, WR, PDM,BTR = DIGITAL PULSE RECORDER

BR, L&N, DG, RA, RB, RL = GRAPHIC DEMAND RECORDER

2 AUXILIARY METERING DEVICE, NUMBER INDICATES TYPE

1 = DC SUPPLY

2 = 3 TO 2 WIRE CONVERSION RELAY

3 = AUXILIARY RELAY

4 = POTENTIAL SELECTOR RELAY

5 = POLARIZED IMPULSE RELAY

6 = FREQUENCY RESPONSE RELAY

7 = 2 TO 3 WIRE CONVERSION RELAY

8 = PULSE VALUE MULTIPLIER

9 = 2 TO 3 WIRE CONVERSION RELAY FO[illegible] TELEPHONE CARRIER CIRCUITS

$\boxed{\text{CTz}}$ TRANSDUCER

CTz = CURRENT TRANSDUCER

VTz = VOLTAGE TRANSDUCER

WTz = WATT TRANSDUCER

WhTz = WATTHOUR TRANSDUCER

VARhRz = VARHOUR TRANSDUCER

W/WhTz = WATT/WATTHOUR TRANSDUCER

Attachment 5

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.

March 1997 - Preliminary RFP Issued

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.

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

August 1997 - Final RFP Issued (including a standard contract)

September 1997 - Bids Due

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 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.

[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. Alternative Individual Year Auction ("Alternative Auction"). 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. Selection of Suppliers from Both Auctions. 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. Payment by Distribution Company. 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.

Distribution Company Rates

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.

Attachment 6

Electric Utility Restructuring Plan
New England Electric System--Proposal for Environmental Component

I. Purpose

The purpose of the environmental component of an electric industry restructuring plan is to provide a means such that a competitive industry structure supports and furthers the efforts of environmental regulators to reduce the environmental impacts of electricity generation. This objective is to be achieved by establishing a program by which older fossil-fueled electric generating facilities will be required to reduce certain air emissions to a level that is roughly equivalent to new source standards. As implemented, the program will not supersede any environmental agency's legal authority to regulate the units nor require the units to meet emission standards other than the most stringent applicable standards required by law. The program is intended to be simple and straight-forward, one that is transferable to other older utility sources in all regions of the country.

II. Generic Components of Proposal

1. The program is designed to require all older fossil-fueled electric generating units throughout the U.S. to meet "old source performance standards" ("OSPS") for NO_x and SO_2 on January 1 of the year following the year a unit becomes 40 years old. The 40 year time period starts from the year a unit commenced commercial operation. For those units that are 40 years or older in the year the program becomes effective, they will be required to meet OSPS by January 1 of the following year. The end point for this program is the year 2010; therefore, all units will be assumed to be 40 years old on or before December 31, 2009.

2. As of the date the program becomes effective, each existing operating unit will receive "allowances" for that unit's emissions of NO_x and SO_2. Each allowance equals one ton of allowable emissions. Unit-specific allowances are aggregated to become a utility company-wide cap.

3. New units or repowered units subject to new source permitting regulations and thus not be included under the program. Emissions from new or repowered units will not be included in determining a company's overall cap of NO_x or SO_2.

4. Unit-specific allowances are calculated as follows:

a. For units 40 years old or older, or by the year 2010:

$$\text{Yearly Net Electrical Generation (kWh)} \times \text{Heat Rate (Btu/kWh)} \times \text{Emission Rate (lbs./MMBtu)} \times \text{Conversion Factor } \frac{1}{2\text{x}10^9} = \text{Tons/Year}$$

The elements of the formula are derived as follows:

i) Yearly Net Electrical Generation = average kWh of the highest eight (8) of ten (10) year period of 1986-1995, as reported on U.S. Department of Energy Form EIA- 767, Schedule IV.

ii) Heat Rate = 10,000 Btu/kWh

iii) Emission Rate = 0.30 lbs/MMBtu for SO_2
0.15 lbs/MMBtu for NO_x

PROVIDED, however, that if a unit's required emission rate is lower than the rates listed above, the lowest, most stringent emission rate applies.

iv) Conversion Factor = factor required to convert differing measures used in formula to result in tons per year of emissions.

b. For units less than 40 years old:

NO_x--- Same formula as in 4.a. above, except that emission rate is set at the regulatory limit.

SO_2--- Allowances as allocated under Acid Rain Program, Title IV of federal Clean Air Act.

5. Each utility company may meet its allowance cap by any combination of control technologies, fuel switching, unit retirements, operational changes and/or retirements of purchased or surplus allowances. Selection of any one or a combination of more than one of these options to meet the company cap will be at the sole discretion of the utility company.

6. SO_2 allowances may be traded freely in the market as allowed under the Clean Air Act, Title IV Acid Rain Program regulations. Unused allowances may be banked and carried forward also as allowed under the Acid Rain Program regulations.

7. It is anticipated that a NO_x trading program will be established similar to the federal SO_2 program. Unused NO_x allowances also may be banked, provided, however, that allowance withdrawals from the bank may be subject to a "flow control" mechanism as specified in the Ozone Transport Commission model rule.

8. With respect to jointly-owned units, their participation in the program will be governed in the same manner as jointly-owned units are governed under the federal Acid Rain Program.

9. The final emission reductions applicable on January 1, 2010, will be subject to the following "trigger" mechanisms which assure that a substantive portion of the national emissions inventory is subject to this program:

   a. If in calendar year 2005, the actual NO_x emissions of the emissions inventory in the Ozone Transport Region ("OTR") and in the East Central Area Reliability Coordination Agreement ("ECAR") and the Mid-America Interconnected Network ("MAIN") of the North American Electric Reliability Council (hereinafter collectively referred to as "the Region") are reduced by no less than 50% from the calendar year 1996 actual NO_x emissions of the emissions inventory in the Region, then implementation of the OSPS for NO_x will be on January 1, 2010. If a reduction of NO_x emissions of 50% or greater is not achieved in calendar year 2005, the actual emissions of the emissions inventory in the Region will be measured in each successive calendar year until such time as the prescribed level of reduction from the year 1996 baseline is actually achieved, and implementation of the OSPS NO_x requirement will be five (5) years from the year the emission reduction of 50% or greater is actually achieved.

   b. If the SO_2 allowances allocated under Title IV of the federal Clean Air Act to the emissions inventory in the Region in the year 2007 are 50% or less of the SO_2 allowance allocation made in the year 2000, then implementation of the OSPS for SO_2 will be on January 1, 2010. If a reduction of 50% or greater is not achieved in the year 2007, the SO_2 allocation will be reviewed in each successive year until such time as the prescribed level of reduction from the year 2000 baseline is actually achieved, and implementation of the OSPS SO_2 requirement will be three (3) years from the year the reduction in allowance allocation of 50% or greater from the year 2000 baseline is actually achieved.

The NO_x- and SO_2-specific triggers described above will be implemented independent of one another.

III. NEES-Specific Requirements Under the Proposal

1. The NEES-specific emission reductions included in this proposal apply to the following fossil-fueled power plants:

   Brayton Point Station, Somerset, MA
   Unit Nos. 1, 2, 3, and 4

   Salem Harbor Station, Salem MA
   Unit Nos., 1, 2, 3, and 4

   New England Power Company ("NEP"), a subsidiary of NEES, is the owner and operator of the Brayton Point and Salem Harbor facilities. NEP may meet its allowance cap by any combination of control technologies, fuel switching, unit retirements, operational changes and/or retirements of purchased or surplus allowances.

2. The program start date for NEP's Brayton Point and Salem Harbor units is 2000. The dates when the Brayton Point and Salem Harbor units will be subject to OSPS are as follows:

Unit No.	Brayton Point	Salem Harbor
1	2004	2000[1]
2	2005	2000[1]
3	2010	2000[1]
4	2010[2]	2000[2]

([1] Although 40 year time period for these three units ends earlier than year indicated, each unit will be subject to OSPS by the year indicated.)

([2] Although 40 year time period for these two units ends later than years indicated, each unit will be subject to OSPS by the years indicated.)

3. The emission reductions profile for all the NEP Brayton Point and Salem Harbor units, absent the NEP-specific triggers described in Section III.5. below, are illustrated in the attached graphs.

4. With respect to SO_2, the total annual cost that may be necessary to achieve the reductions included in this proposal is capped as follows:

Year(s)	Annual Cost Cap
2000-2003	$1.9MM p/year
2004	$2.7MM p/year
2005-2009	$3.5MM p/year
2010 and beyond	$6.0MM p/year

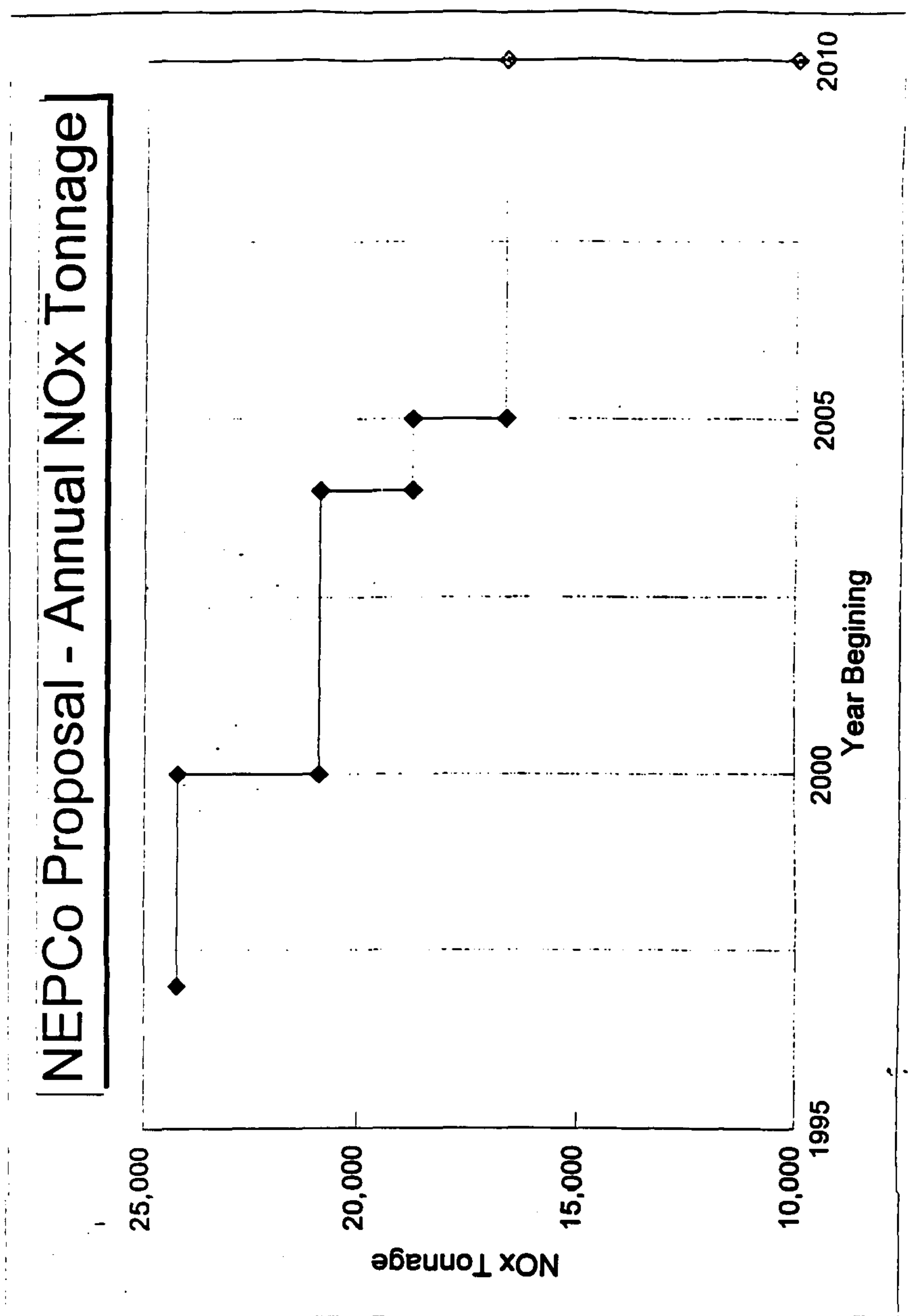
provided, however, that the cost cap for the year 2010 and beyond will remain at $3.5MM p/year if the SO_2 trigger in Section II.9. is not met. Once the trigger is met, the cost cap will increase to $6.0MM p/year. Whether the annual tonnage cap of SO_2 is achieved in any given year is limited by the annual cost cap applicable in that year.

5. With respect to NO_x, the following additional triggers apply to NEP:

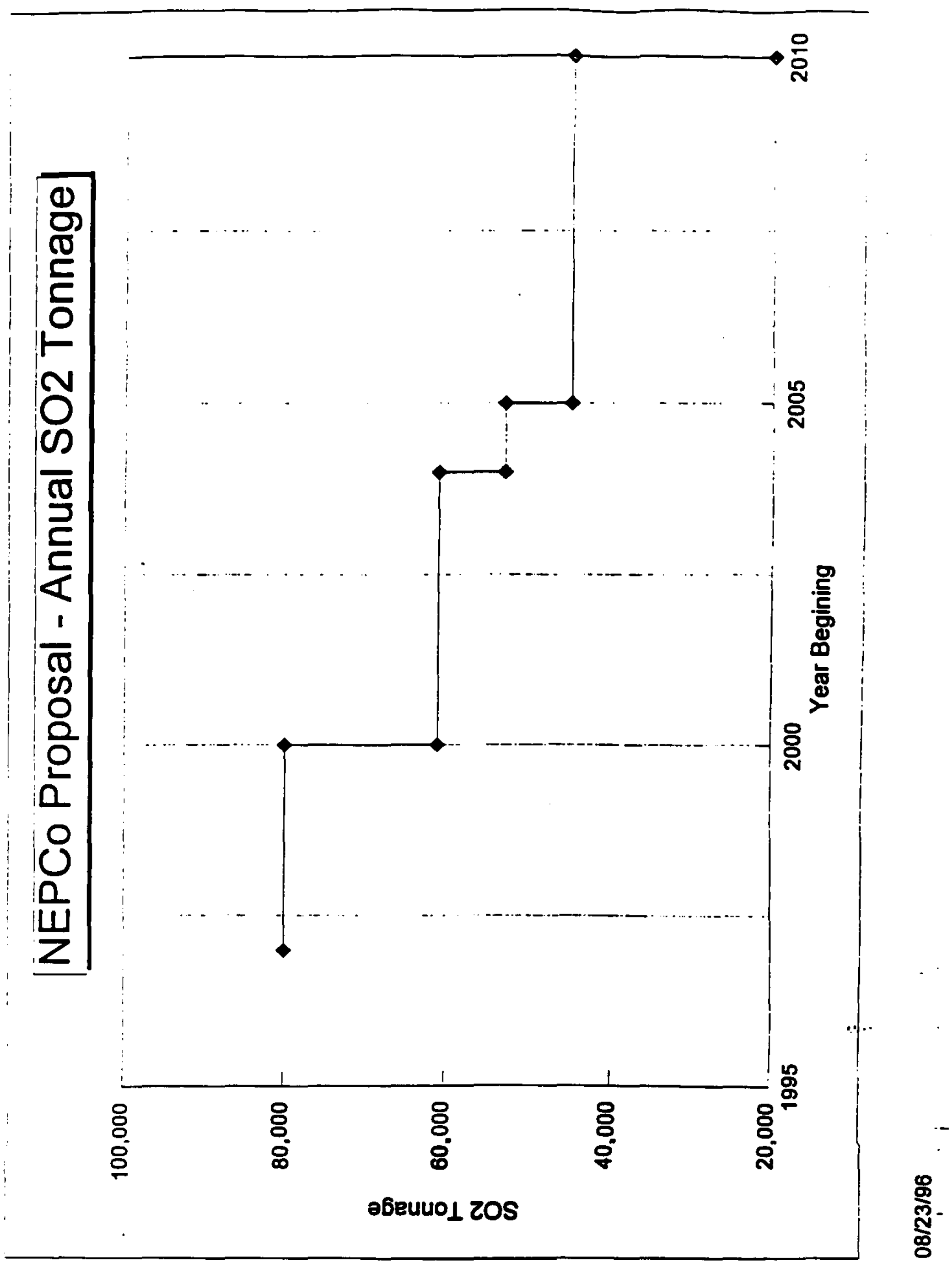
   a. On January 1, 2003, Brayton Point Unit Nos. 1 and 2 will receive allowances calculated pursuant to Section II.4.a. of this proposal if in calendar year 2000 the actual NO_x emissions of the emissions inventory in the Region is reduced by no less than 50% from the emissions of the emissions inventory in the Region in the baseline year of 1990. If a reduction of 50% or greater is not achieved in calendar year 2000, the actual emissions of the emissions inventory will be measured in each successive calendar year until such time as the prescribed level of reduction from the year 1990 baseline is actually achieved. Brayton Point Unit Nos. 1 and 2 will receive allowances pursuant to Section II.4.a. of this proposal in the third year after the prescribed reductions in the emissions inventory are actually achieved; provided, however, that in no event shall the date the units are subject to the OSPS requirements of Section II.4. go beyond January 1, 2004 for Brayton Point Unit No. 1 and January 1, 2005 for Brayton Point Unit No. 2.

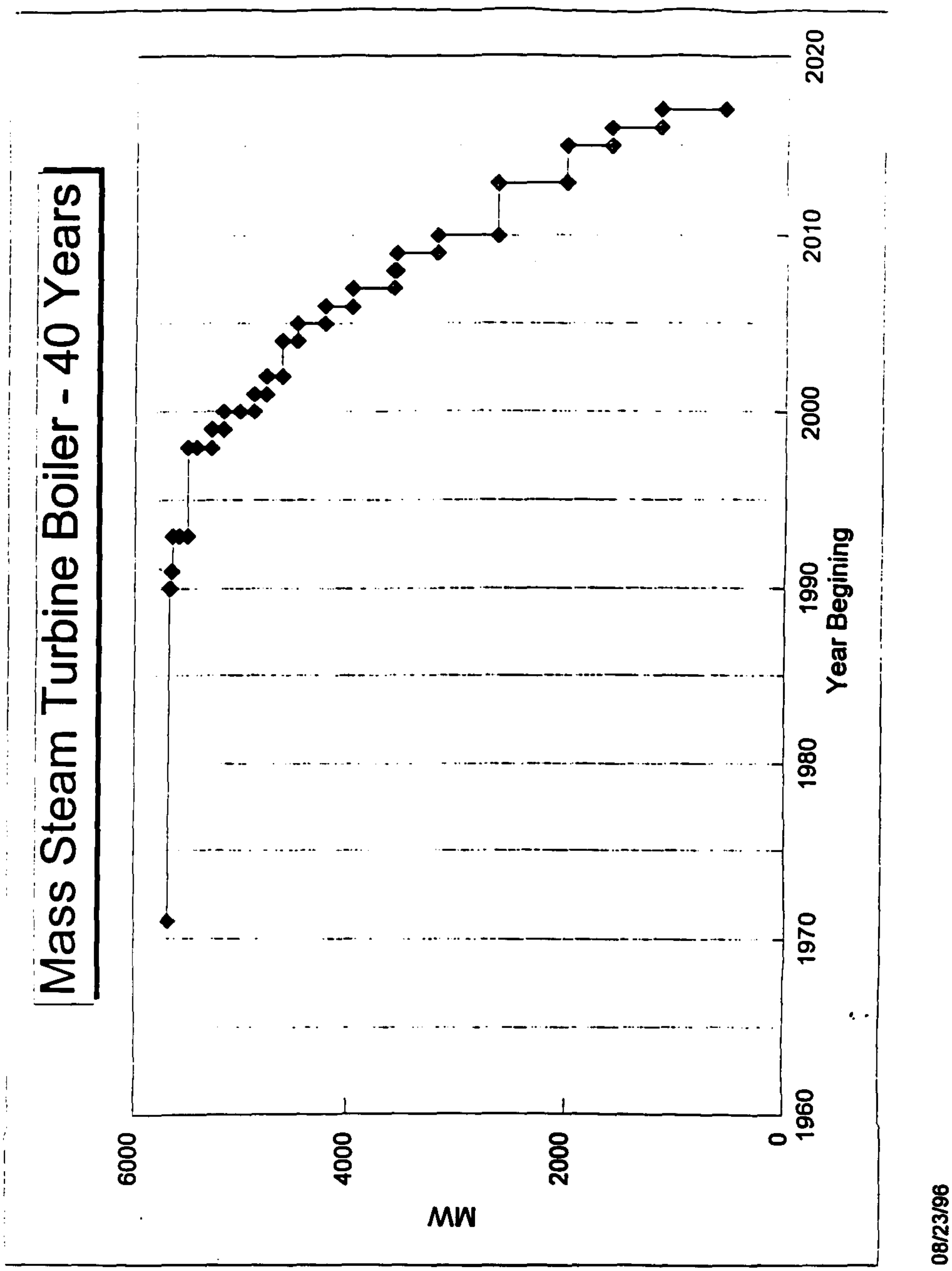
   b. On January 1, 2007, Brayton Point Unit No. 3 will receive allowances calculated pursuant to Section II.4.a. of this proposal if in calendar year 2003 the actual NO_x emissions of the emissions inventory in the Region is reduced by no less than 75% from the emissions of the emissions inventory in the Region in the baseline year of 1990. If a reduction of 75% or greater is not achieved in calendar year 2003, the actual emissions of the emissions inventory will be measured in each successive calendar year until such time as the prescribed level of reduction from the year 1990 baseline is actually achieved. Brayton Point Unit No. 3 will receive allowances pursuant to

Section II.4.a. of this proposal in the fourth year the after prescribed reductions in the emissions inventory are actually achieved; provided, however, that allowances for Brayton Point Unit No. 3 will be calculated pursuant to Section II.4.a. of this proposal by no later than January 1, 2010 subject to the NO_x trigger specified in Section II.9. of this proposal.


NEPCo Proposal - Annual NOx Tonnage
NOx Tonnage
25,000
20,000
15,000
10,000
1995
2000
2005
2010
Year Begining

08/23/96


NEPCo Proposal - Annual SO2 Tonnage
SO2 Tonnage
100,000
80,000
60,000
40,000
20,000
1995
2000
2005
2010
Year Begining
08/23/96


Mass Steam Turbine Boiler - 40 Years
MW
6000
4000
2000
0
1960
1970
1980
1990
2000
2010
2020
Year Begining
08/23/96

Massachusetts Steam Turbine / Boiler Units

UTILITY	UNIT	FUEL TYPE	WINTER NET CAPACITY (MW)	COMMISSIONING YEAR
BECO	NEW BOS 1	OIL/GAS	380	1965
	NEW BOS 2	OIL/GAS	380	1967
	MYSTIC 4	OIL	135	1957
	MYSTIC 5	OIL	126	1959
	MYSTIC 6	OIL	138	1961
	MYSTIC 7	OIL/GAS	592	1975
CES	BLACKSTONE 1	OIL/GAS	16	1930
	CANAL 1	OIL	557	1968
	CANAL 2	OIL/GAS	584	1976
	KENDALL 1-3	OIL/GAS	64	1950 (EST)
EUA	SOMERSET 6	COAL	110	1959
HOLYOKE	CABOT 6&8	OIL/GAS	14	1949
NU	MOUNT TOM	COAL	147	1960
	W SPRINGFIELD3	OIL/GAS	107	1957
TMLP	CLEARY 8	OIL	26	1966
NEPCO	BP1	COAL	255	1963
	BP2	COAL	253	1964
	BP3	COAL	622	1969
	BP4	OIL/GAS	446	1974
	SH1	COAL	84	1952
	SH2	COAL	80	1952
	SH3	COAL	150	1958
	SH4	OIL	400	1972

MASSACHUSETTS TOTAL STEAM TURBINE CAPACITY (MW) 5666

08/23/96

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

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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.

[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),

[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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Laura S. Olton

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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 14, 2005

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COMMISSION

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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

Docket No: ER97-2800-000
Company: Montaup Elec. Co.
Supplement No.: 2
To [illegible] No: 10
[illegible] 1R1
[illegible] 10-29-97
[illegible] 11-1-98.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Montaup Electric Company	)	Docket No.. ER97-2800-000

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 ("RIPUC"), the Rhode Island Division of Public Utilities and Carriers ("RI Division"), Montaup Electric Company (" Montaup"), Blackstone Valley Electric Company (" Blackstone") and Newport Electric Corporation ("Newport"). The foregoing entities are referred to as the Signatories.

Montaup is now obligated to sell electric energy at wholesale to meet the service area requirements of both Blackstone and Newport pursuant to its FERC Electric Tariff, First Revised Volume No. 1 ("Tariff 1"). The RIPUC and RI Division are authorized under the Rhode Island General Laws to participate in all proceedings before the Federal Energy Regulatory Commission (" FERC") with respect to the modification and/or termination of the wholesale Tariff 1.

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1.2 Introduction.

This Agreement is designed to implement a resolution of the issues presented by the restructuring of the contract relationship between Montaup and Blackstone and between Montaup and Newport arising out of the passage by the Rhode Island Legislature of the Utility Restructuring Act of 1996 ("URA").

Under Tariff 1, Montaup is obligated to sell to Blackstone and Newport, and Blackstone and Newport are obligated to purchase from Montaup, the requirements of their retail service territories, and they may only terminate those mutual obligations upon three years' notice. The Signatories to this Agreement desire to terminate those obligations earlier in order that retail choice in Rhode Island can proceed as set forth in the URA and in order to provide additional benefits to all electric consumers in Rhode Island.

The URA extends competition in power supply markets to retail customers through the provision of retail access directly to Blackstone's and Newport's customers. Termination of Tariff 1 and the provision of unbundled transmission service by Montaup to Blackstone and Newport under Montaup's open access tariff are both necessary to implement retail access in a manner consistent with the URA. In addition, the provisions of this Agreement provide additional assurance, beyond those reflected in the URA, that consumers will benefit from expanded competition in wholesale and retail power supply markets and that competition will take place on an open and non-discriminatory basis.

This Agreement, all provisions of which are interdependent, except where expressly stated otherwise, is intended upon its acceptance by FERC 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 Blackstone's and Newport's Service Agreements with Montaup. Nothing in the language of this Agreement shall be construed to permit Montaup, Blackstone or Newport to recover more than once any of the charges authorized hereunder.

ARTICLE 2.0
AMENDMENT OF SERVICE AGREEMENT AND WHOLESALE RATE FREEZE

2.1 Amendment of Service Agreement.

The Service Agreements between Montaup and Blackstone and between Montaup and Newport shall be amended in accordance with the Amendment to the Service Agreement included in Attachments 1B and 1N ("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 Montaup, Blackstone and Newport, including, without limitation, provisions for the payment and collection of Contract Termination Charges, that are just, reasonable and in the public interest.

2.2 Wholesale Rate Freeze

Blackstone and Newport are now served by Montaup under Montaup's wholesale rate M-14 approved by FERC in Docket ER94-1062-000. As set forth in the Amendment, the M-14 base rates in effect as of January 1, 1997 shall remain in effect for Montaup's service to Blackstone and Newport through the Contract Termination Date defined in Section 3.1 below. Nothing in this Agreement or the Amendment shall preclude Montaup from petitioning FERC for modification of Montaup's fuel or purchase power clauses.

ARTICLE 3.0
CONTRACT TERMINATION

3.1 Contract Termination Date Defined.

As specified in the Amendment, Montaup's obligations to provide requirements service to Blackstone and Newport shall cease on the Contract Termination Date. The Contract Termination Date shall occur on the earlier of the Retail Access Date or the Wholesale Access Date, defined as follows:

3.1.1 The Retail Access Date shall be the later of January 1, 1998 or the date of a final, nonappealable order of the RIPUC approving the implementation methodology for the disposition of Montaup's non-nuclear generating facilities, provided, however, the Retail Access Date shall occur no later than three months after retail access is made available to forty percent (40%) or more of the kilowatt-hour sales in New England, including the total kilowatt-hour sales in Rhode Island, and in any event, not later than July 1, 1998.

3.1.2 The Wholesale Access Date shall be the earlier of the Retail Access Date or the date on which Blackstone or Newport in its sole discretion decides to terminate purchases under Tariff 1 and its Service Agreement with Montaup by providing FERC and the Signatories with 90 days advance notice in writing, or less with the mutual consent of the parties, said date not to be earlier than January 1, 1998.

3.2 Contract Termination Charges.

Commencing on the Contract Termination Date, Blackstone and Newport shall pay Montaup the Contract Termination Charges pursuant to the terms of the Amendment. If this Agreement is approved by FERC, the Amendment shall be deemed to be a just and reasonable rate for wholesale electric service pursuant to the Federal Power Act and FERC's regulations. The Contract Termination Charges under the Amendment shall apply to all kilowatthours delivered by Blackstone or Newport or their successors or assigns in Blackstone's or Newport's Service Areas. Service Areas are defined to include the area served by Blackstone and Newport on December 1, 1996. Kilowatthours delivered are defined to include all kilowatthours delivered to electricity consumers in Blackstone's or Newport's Service Areas, whether or not they are present customers of Blackstone or Newport. 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 Blackstone's and Newport's proportionate share of Montaup's total contract termination costs shown in Schedule 1 to the Amendment, which respective shares equal 29.13 percent and 11.85 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, Montaup has agreed to a divestiture of its generation business within six months after the later of (1) the Retail Access Date as defined in Montaup's settlement with Eastern Edison Company ("Eastern") in Docket ER97-3127-000, or (2) the receipt of all governmental approvals necessary for such divestiture. Within three months after the sale of any or all of Montaup's generating facilities or any other property subject to divestiture, Montaup 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 deemed to be fully implemented upon completion of the initial divestiture process for Montaup's non-nuclear generating facilities. The Residual Value Credit shall be calculated as set forth in the Amendment.

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 Montaup to Blackstone and Newport. The Reconciliation Account shall be calculated as set forth in the Amendment.

3.5 Resolution of Disputes Associated with the Implementation of the Contract Termination Charge.

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 and adjustments to the Contract Termination Charges to Blackstone and Newport made by Montaup pursuant to sections 3.3 and 3.4, and the calculation of the purchased power mitigation incentive are, to the extent possible, to be resolved informally and, accordingly, such disputes may not be submitted to FERC 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 FERC from examining any such adjustment including, without limitation, any capital addition made by Montaup after December 31, 1995, by opening its own investigation. Within 30 days after it has modified Blackstone's and Newport's Contract Termination Charges to reflect the Residual Value Credit or a Reconciliation Adjustment, Montaup shall submit to the Signatories, and to any person or entity that is to receive, under FERC's regulations, notice of Montaup rate filings affecting Blackstone and Newport, including, but not limited to the RIPUC and RI Division, an explanation of the adjustment including supporting workpapers. If a recipient desires to challenge any portion of the adjustment, it shall advise Montaup in writing identifying the basis for its dispute. Montaup shall, within 30 days, respond in writing. If the recipient is not satisfied with Montaup's further explanation it shall, within 15 days, notify Montaup in writing of any remaining disagreements and may request that Montaup convene a conference which is to be held within 30 days of such request. The Signatories are to receive from Montaup written notice of, and may participate at, any such conference and are to be provided all written communications relevant to the dispute. At such 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 Montaup's adjustment, it may petition FERC 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 FERC action, it is determined that Montaup's calculation of the Residual Value Credit or Reconciliation Account balances for Blackstone's and Newport's Contract Termination Charges were inappropriate, the credit or charges shall nevertheless remain in effect for the balance of the calendar year but Montaup shall adjust the Reconciliation Account for any such overcharge, together with a return equal to that specified in Section 1.1.2 of Appendix 1 to the Amendment, and shall reflect that adjustment in Blackstone's and Newport'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 Montaup has collected all amounts subject to collection thereunder. Neither the formulae as set forth in Appendix 1 and Schedules 1 and 2 to the Amendment nor the Contract Termination Charges recoverable under this Agreement and the Amendment shall be subject to change through application to FERC pursuant to the provisions of Section 205 or Section 206 of the Federal Power Act, absent the agreement of Montaup or its successors or assigns.

3.7 Hold Harmless Deferral

Effective on July 1, 1997, Montaup shall institute a Hold Harmless Deferral ("HHD"), in accordance with Article 6 of the Amendment, to defer a portion of the M-Rate Billings to Blackstone and Newport to ensure Blackstone and Newport are held harmless as a result of the phase in of retail access in Rhode Island.

ARTICLE 4.0
TRANSMISSION

4.1 Montaup to Provide Network Integration Transmission Service.

Effective on the Contract Termination Date, Montaup shall provide Blackstone and Newport Network Integration Transmission Service under Montaup's 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 Attachments 2B and 2N to this Agreement. The Network Integration Transmission Service provided under the Service Agreement shall include transmission service necessary for Blackstone and Newport to provide transmission and distribution access to retail customers. The Signatories to this Agreement support the approval by FERC of Attachments 2B and 2N as filed as part of this Agreement. However, with the exception of the commitments in the following paragraph, approval of Attachments 2B and 2N without change is not a condition of this Agreement. Rather, with respect to transmission access and pricing, Montaup, Blackstone and Newport will modify the Transmission Service Agreement in a manner that is necessary to accommodate FERC's policy.

In addition to the charges for Network Integration Transmission Service, in the event Blackstone or Newport is denied the ability to recover in its transition charges established for the provision of local distribution service the full amount of the Contract Termination Charges billed to them, Montaup 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 Blackstone and Newport or to every consumer located in their Service Area that takes delivery of electric energy from the transmission facilities of Montaup and the distribution facilities of Blackstone and Newport. The amount of any such surcharge shall be submitted to the Federal Energy Regulatory Commission for review by a filing under section 205 of the Federal Power Act. Approval of this provision is a condition of this Agreement.

4.2 Separation of Transmission and Distribution Facilities.

In Order 888, FERC set forth a seven-factor test for determining whether facilities used to provide access to ultimate customers are subject to the ratemaking jurisdiction of FERC or of the RIPUC under state law. Blackstone and Newport have completed such an analysis for the jurisdictional separation of their facilities. The analysis was approved by the RIPUC on June 4, 1997 in Docket 2514, and is included as Attachment 3 to this Agreement. Based on that analysis, the Signatories agree that all of Blackstone's and Newport's facilities meet FERC's seven-factor test for designation as distribution facilities subject to the RIPUC's jurisdiction with two exceptions. The first exception consists of the facilities that are paid for by Montaup pursuant to FERC Rate Schedules No. 19, No. 21 and No. 6. The Signatories agree that those facilities are transmission facilities subject to FERC'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 Blackstone and Newport as distribution although they could be classified as transmission under FERC'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 Blackstone, Newport and Montaup, their historical classification as distribution plant should be retained. The Signatories to this Agreement therefore support the approval by FERC of the jurisdictional separation of facilities set forth in Attachment 3. However, approval of the jurisdictional separation of facilities without change is not a condition of this Agreement.

4.3 Sale of Assets.

If, within twelve years from the date of this Agreement, Montaup 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 Montaup will credit any net proceeds in excess of book value to the Reconciliation Account.

ARTICLE 5.0
TRANSITIONAL SERVICE

5.1 Standard Offer Service.

Standard Offer Service shall consist of the wholesale supply of power sufficient to meet the requirements of retail customers served by Blackstone's and Newport's distribution facilities that purchase Standard Offer retail service from Blackstone and Newport. For the period from the Contract Termination Date through December 31, 2009, Montaup shall provide Blackstone and Newport with Standard Offer Service.[1] 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
2008	6.7 cents
2009	7.1 cents

The prices shown above shall be for electricity delivered to the meter of Blackstone's and Newport's ultimate customers, not including the charges for Blackstone's and Newport's

[1] Montaup, Blackstone and Newport shall have the right in their sole discretion to shorten the period of Standard Offer Service to December 31, 2004, if Blackstone and Newport no longer have the obligation under the Rhode Island URA to extend Standard Offer Service through 2009.

distribution services or for Montaup's Network Integration Transmission Service, but including any and all transmission charges to reach Montaup's system that are not recovered in Blackstone's and Newport's transmission cost adjustment provisions. Standard Offer Service shall be available to Blackstone and Newport after the Wholesale Access Date or to their ultimate customers after the Retail Access Date. After those dates, Blackstone and Newport are free to reduce their purchases under the Standard Offer by pursuing other opportunities in the wholesale market, and their ultimate customers may terminate Standard Offer Service at any time to purchase from a non-regulated power producer as defined in Section 39-1-2(7.1) of the Rhode Island General Laws. Once Blackstone and Newport have reduced their wholesale purchases for those ultimate customers who have terminated Standard Offer Service, they may only elect to increase their purchase for any of Blackstone's and Newport's residential or small general service customers who have taken service from a non-regulated power producer within the first year after the Retail Access Date and such residential or small general service customer elects to return to Standard Offer Service within 120 days of taking service from such non-regulated power producer.

5.2 Right to Bid the Standard Offer.

Blackstone and Newport shall offer alternative suppliers the opportunity to bid on the provision of Standard Offer Service. Blackstone and Newport shall have the ability to defer the bid for standard offer service to coordinate with the Standard Offer Service auction of their affiliate, Eastern. The terms for the bid shall be as set forth in Attachment 4. Montaup 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, Montaup, its successors or assignees shall guarantee to provide the unsubscribed portion of such service to Blackstone and Newport at the prices set forth in Section 5.1.

5.3 Assignment by Montaup of Unsubscribed Standard Offer Obligation through Divestiture

As Montaup has agreed to divest its generating business, as set forth in Article 6.0, it will assign the obligation to provide a share of the unsubscribed portion of Standard Offer service with each unit divested in proportion to that unit's contribution to providing Blackstone's and Newport's energy requirements. Montaup will have no further obligation for Standard Offer backstop service so assigned. Any Standard Offer service obligation remaining with Montaup after completion of the divestiture will be supplied first from Montaup's remaining power contracts then from Montaup's remaining nuclear units at the prices set forth in Section 5.1. Montaup will purchase capacity and energy to meet any obligatory Standard Offer Service at the prices set forth in Section 5.1 that cannot be served from Montaup's remaining purchase power and nuclear units.

5.4 Montaup's Obligation to Install Additional Generation Terminated.

Effective on the Contract Termination Date, Montaup shall have no further obligation to meet the electricity demands of Blackstone or Newport, and nothing in this Agreement shall be deemed to require Montaup to make any plan, investment, purchase, or commitment to maintain sufficient generating capacity to provide adequate, continuous, or reliable electricity supplies to Blackstone or Newport except as required to fulfill

Montaup's obligation under this Agreement to provide Standard Offer Service or as is expressly set forth in a separate power purchase contract between Montaup and Blackstone or between Montaup and Newport.

ARTICLE 6.0
DIVESTITURE AND MARKET PRICING OF MONTAUP'S GENERATION

6.1 Divestiture of Montaup's Generating Business.

6.1.1 Montaup agrees, subject to the receipt of all required governmental approvals, to lease, 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: properties currently held in FERC Account 105 Land Held for Future Use - (Production) and FERC Account 121 Nonutility Property. Montaup has developed and, on July 1, 1997 filed with FERC in Docket Nos. ER97-2800-000 and ER97-3127-000, a plan to implement divestiture. This plan includes 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. ER97-3127-000, 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. FERC 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, Montaup 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 Montaup to retain the obligation for post-shutdown, decommissioning, and site restoration for these units or entitlements. Montaup shall recover these post-shutdown, decommissioning, and site restoration costs from Blackstone and Newport 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 Signatories agree that this approach is reasonable and Montaup 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 Montaup is unable to sell, lease, assign, or otherwise dispose of its nuclear units or entitlements, Montaup 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,[2] 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, Montaup will consult with the Signatories on a performance standard for nuclear safety indicators and will file such performance standard

[2] 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.

with a maximum potential credit for nonperformance of $250,000. Montaup 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. Montaup's sales, if any, from its nuclear units shall not be made directly to retail customers of Blackstone and Newport, however these units may be used by Montaup to fulfill its backstop obligations under the Standard Offer.

6.1.3 As part of the divestiture, Montaup 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 not be made directly to retail customers of Blackstone and Newport, however, the contracts, including that with Hydro Quebec, may be used by Montaup to fulfill its backstop obligations under the Standard Offer. Nothing in this Settlement shall affect the rights of suppliers or Montaup 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. Montaup, Blackstone and Newport have agreed, as part of this Agreement, voluntarily to undertake such divestiture. In exchange, and as consideration for this voluntary divestiture, the Signatories and FERC by its approval of this Agreement, agree that Montaup's Contract Termination Charges to Blackstone and Newport and, in the circumstances described in the second paragraph of section 4.1, to every consumer located in their Service Areas 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, FERC 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 FERC 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, FERC or 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 Montaup, 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 Montaup's Generation.

To facilitate the divestiture and valuation of Montaup's units, the Signatories agree that it is in the public interest for Montaup or its successors or assigns to be authorized to price its wholesale electricity sales subject to the FERC's jurisdiction at market prices. The Signatories to this Agreement support the approval by FERC of market pricing for Montaup'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 two states in which Montaup provides wholesale service to affiliate distribution companies, Montaup 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 of Montaup'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 Montaup or an affiliate from re-entering the generation business following the completion of divestiture, and nothing in this Agreement shall prevent Montaup or an affiliate from marketing electricity, other energy sources, or energy services to customers within or outside Blackstone's or Newport's Service Areas.

6.5 Environmental Commitments at Montaup's Facilities.

Subject to the DPU approving Eastern's Restructuring Settlement, Montaup or its successors in interest shall reduce the emissions of NO_x and SO_2 from its Somerset Station and its share of Canal No. 2 by the amounts and on the schedule and terms set forth in Eastern's Restructuring Settlement.

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 Montaup, Blackstone and Newport to each other under Tariff 1, in connection with the introduction of wholesale and retail competition for electricity supplies in Blackstone's and Newport's Service Areas . The willingness and ability of Montaup, Blackstone and Newport to commit to and fulfill any and all of their obligations under this Agreement are predicated and conditioned upon FERC's approval of Montaup's Contract Termination Charges to Blackstone and Newport and the commitments by the other Signatories to this Agreement to such recovery.

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

8.4 FERC'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, Montaup shall nevertheless be held harmless and made whole for the payments it has agreed to accept as consideration for relinquishing its existing rights under Montaup'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 FERC and on the further condition that if FERC 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.

IN WITNESS WHEREOF, each of the Signatories has executed Agreement, intending to be bound by its terms.

Montaup Electric Company
Settlement Agreement

FERC Docket No. ER97-2800-000

Alan Shoer
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Counsel for Rhode Island
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October 9, 1997

Robert G. Powderly
Executive Vice President

John D. Carney
President
Blackstone Valley Electric Company
Newport Electric Corporation

October 17, 1997

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Montaup Electric Company
Settlement Agreement

FERC Docket No. ER97-2800-000

Harvey L. Reiter
Counsel for Rhode Island
Public Utilities Commission

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October 17, 1997

APPENDIX 1

FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

RI (BVE)

12/5/97

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Appendix I

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 Maine Yankee and Vermont Yankee Units, 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;
(v) Unamortized ITC; and
(vi) Montaup's share of unamortized debt expense recorded on the balance sheet of its parent, Eastern Edison Company.

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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

[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.

facilities ("Divestiture Date")[3], and sufficient to provide an overall pretax return 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, excluding the unamortized ITC under 1.1.1(b)(v), 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

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[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.

[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, and the difference between the 11.34 percent and 13.09 percent returns that occurs after the Divestiture Date shall be included in the Reconciliation Account. The 11.34 percent and 13.09 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. However, the 13.09 percent return after the Divestiture Date shall be adjusted in accordance with Section 1.1.4(d). 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.

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

SM 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 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.

N/A 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

[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.

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 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.

N/A (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 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 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.

[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.

VA (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 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]

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[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.

[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

equal to the sale price and other consideration received by Montaup excluding $15 million[2] which purchasers will be required to pay into an account for employee benefits pursuant to Section 1.2.2(f), 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 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

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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.

[2] This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

kilowatthours delivered[10] 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,[11] 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.

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

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[10] "Delivered", as used herein, refers to the kilowatt hours delivered by Newport other than of purchases from Montaup under Rate M-14.

[11] 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.

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.

NA (d) Effective with refinancings, repurchases, and retirements of securities 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 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.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust Montaup's Base Contract Termination Charges to Blackstone on January 1, 2001. Thus, effective January 1, 2001, Montaup shall return or collect Blackstone's allocated share of any outstanding balance in the Reconciliation Account by implementing an adjustment to the Base Contract Termination Charges to Blackstone. Thereafter, 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. Any Reconciliation

Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract Termination Charge to increase or decrease by more than 0.2 cent per kilowatthour shall be implemented up to 0.2 cents per kilowatthour. The excess above 0.2 cents per kilowatthour shall be amortized with a return over the three years following January 1, 2001.

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:

JM (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 and Connecticut 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) Above Market Payments to Power Suppliers 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 andsupport 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

NA (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, BVF

Appendix 1

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) 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

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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.

GM (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, Connecticut Yankee, Maine Yankee, 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. PT

NHA (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.

NHA (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. Montaup shall require purchasers of its generating assets to pay $15 million[12] for the costs under this paragraph incurred by Montaup or its affiliates. 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

[12] 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.

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

NHA (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.

MA (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,[13] 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

[13] 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.

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 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.

NA (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;

N/A (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 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;

N/A (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).

SCHEDULE 1

SUMMARY OF CONTRACT TERMINATION CHARGES

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

Schedule1
Page 1 of 15

YEAR (1)	LST BVE 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 TOT TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARG CENTS/KWH (8)
1998	1,293,212	14,900	1.15	23,897	1.85	38,796	3.00
1999	1,309,137	16,084	1.23	23,190	1.77	39,274	3.00
2000	1,329,905	16,899	1.27	22,998	1.73	39,897	3.00
2001	1,346,024	13,060	0.97	23,084	1.72	36,145	2.69
2002	1,360,074	15,070	1.11	19,955	1.47	35,026	2.58
2003	1,377,851	16,099	1.17	17,931	1.30	34,030	2.47
2004	1,399,848	16,895	1.21	16,261	1.16	33,157	2.37
2005	1,423,866	15,343	1.08	17,001	1.19	32,344	2.27
2006	1,452,574	15,967	1.10	15,677	1.08	31,644	2.18
2007	1,471,219	14,203	0.97	16,535	1.12	30,737	2.09
2008	1,493,432	15,041	1.01	14,882	1.00	29,923	2.00
2009	1,512,696	12,836	0.85	16,231	1.07	29,067	1.92
2010	1,534,838	0	0.00	13,437	0.88	13,437	0.88
2011	1,550,396	0	0.00	12,585	0.81	12,585	0.81
2012	1,566,958	0	0.00	7,517	0.48	7,517	0.48
2013	1,597,666	0	0.00	3,988	0.25	3,988	0.25
2014	1,624,096	0	0.00	4,126	0.25	4,126	0.25
2015	1,644,785	0	0.00	2,802	0.17	2,802	0.17
2016	1,671,116	0	0.00	2,758	0.17	2,758	0.17
2017	1,693,977	0	0.00	2,140	0.13	2,140	0.13
2018	1,713,946	0	0.00	1,999	0.12	1,999	0.12
2019	1,739,097	0	0.00	2,018	0.12	2,018	0.12
2020	1,762,428	0	0.00	2,084	0.12	2,084	0.12
2021	1,787,024	0	0.00	1,797	0.10	1,797	0.10
2022	1,811,988	0	0.00	514	0.03	514	0.03
2023	1,837,328	0	0.00	529	0.03	529	0.03
2024	1,863,048	0	0.00	545	0.03	545	0.03
2025	1,889,155	0	0.00	561	0.03	561	0.03
2026	1,915,656	0	0.00	201	0.01	201	0.01
2027	2,011,439	0	0.00	207	0.01	207	0.01
2028	2,112,011	0	0.00	214	0.01	214	0.01
2029	2,217,611	0	0.00	220	0.01	220	0.01

182,397

COLUMN NOTES
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST
(3) SCHEDULE 1, P2, COLUMN (8)
(4) COLUMN (3)/COLUMN (2)
(5) SEE SCHEDULE 1, P 3, COLUMN (18)
(6) COLUMN (5)/COLUMN (2)
(7) COLUMN (3) + COLUMN (5)
(8) COLUMN (7)/COLUMN (2)

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Schedule 1
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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 (6)	ADJ. FOR RESIDUAL VALUE CREDIT (7)	NET FIXED COMPONENT INCLUDING ADJ. FOR RESIDUAL VALUE CREDIT (8)
1998	9,035	5,507	357	14,900	0	14,900
1999	8,517	7,225	343	16,084	0	16,084
2000	7,876	8,694	329	16,899	0	16,899
2001	7,304	5,441	315	13,060	0	13,060
2002	6,758	8,012	301	15,070	0	15,070
2003	6,047	9,766	287	16,099	0	16,099
2004	5,205	11,418	272	16,895	0	16,895
2005	4,325	10,759	258	15,343	0	15,343
2006	3,411	12,312	244	15,967	0	15,967
2007	2,469	11,504	230	14,203	0	14,203
2008	1,487	13,338	216	15,041	0	15,041
2009	481	12,154	202	12,836	0	12,836

COLUMN NOTES:
EACH COLUMN REPRESENTS 29 13% OF THE SAME COLUMN NUMBER ON P. 12.

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PAGE.02

Schedule [illegible]
Page [illegible]

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

YEAR (1)	[illegible] POST-RETIREMENT COSTS (2)	TOTAL GENERATION (3)	MARKET VALUE (4)	NET [illegible] MARKET (5)	CAPACITY CONTRACT [illegible] (6)	TOTAL GENERATION (7)	MARKET VALUE (8)	NET [illegible] MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	[illegible] (11)	[illegible] (12)	EMPLOYEE SEVERANCE & RETRAINING COSTS (13)	[illegible] (14)	[illegible] (15)	BASE TOTAL VARIABLE COMPONENT (16)	[illegible] (17)	[illegible] (18)
1998	2,114	42,517	20,062	22,454	0	(1,414)	0	(1,414)	138	[illegible]	0	0	0	[illegible]	23,897	0	[illegible]
1999	2,052	42,556	20,729	[illegible]	0	(1,297)	0	(1,297)	131	[illegible]	0	0	0	[illegible]	23,190	0	[illegible]
2000	1,651	42,456	21,057	[illegible]	0	(650)	0	(650)	125	[illegible]	0	0	0	[illegible]	22,088	0	[illegible]
2001	1,501	40,525	19,024	[illegible]	0	(451)	0	(451)	115	[illegible]	0	0	0	[illegible]	23,004	0	[illegible]
2002	1,495	37,767	16,160	16,446	0	(451)	0	(451)	105	[illegible]	0	0	0	0	19,955	0	[illegible]
2003	1,519	31,540	15,515	[illegible]	0	(451)	0	(451)	101	[illegible]	0	0	0	0	17,831	0	[illegible]
2004	1,556	31,431	16,700	14,711	0	(451)	0	(451)	91	[illegible]	0	0	0	0	16,261	0	[illegible]
2005	1,560	31,905	16,552	15,411	0	(451)	0	(451)	85	[illegible]	0	0	0	0	17,001	0	[illegible]
2006	1,574	31,440	17,706	14,110	0	(451)	0	(451)	77	[illegible]	0	0	0	0	15,677	0	[illegible]
2007	1,595	32,775	17,585	15,189	0	(451)	0	(451)	69	[illegible]	0	0	0	0	16,535	0	[illegible]
2008	647	31,773	16,575	14,256	0	(451)	0	(451)	61	[illegible]	0	0	0	0	14,882	0	[illegible]
2009	509	30,507	16,749	15,802	0	(451)	0	(451)	54	[illegible]	0	0	0	0	16,231	0	[illegible]
2010	567	[illegible]	20,158	13,770	0	(451)	0	(451)	45	0	0	0	0	0	13,437	0	[illegible]
2011	578	26,734	14,285	12,449	0	(451)	0	(451)	37	0	0	0	0	0	12,565	0	[illegible]
2012	434	12,703	5,167	7,536	0	(451)	0	(451)	[illegible]	0	0	0	0	0	7,517	0	[illegible]
2013	444	7,171	3,124	4,047	0	(451)	0	(451)	[illegible]	0	0	0	0	0	3,888	0	[illegible]
2014	405	7,167	1,161	4,171	0	(451)	0	(451)	0	0	0	0	0	0	4,126	0	[illegible]
2015	417	5,894	1,056	2,640	0	(451)	0	(451)	0	0	0	0	0	0	2,802	0	[illegible]
2016	430	5,970	3,166	2,761	0	(451)	0	(451)	0	0	0	0	0	0	2,750	0	[illegible]
2017	441	4,157	2,140	1,697	0	0	0	0	0	0	0	0	0	0	2,140	0	[illegible]
2018	456	4,757	2,215	1,542	0	0	0	0	0	0	0	0	0	0	1,999	0	[illegible]
2019	470	4,161	2,661	1,548	0	0	0	0	0	0	0	0	0	0	2,010	0	[illegible]
2020	484	4,161	2,561	1,600	0	0	0	0	0	0	0	0	0	0	2,044	0	[illegible]
2021	498	1,939	2,621	1,290	0	0	0	0	0	0	0	0	0	0	1,797	0	[illegible]
2022	514	0	0	0	0	0	0	0	0	0	0	0	0	0	514	0	[illegible]
2023	529	0	0	0	0	0	0	0	0	0	0	0	0	0	529	0	[illegible]
2024	545	0	0	0	0	0	0	0	0	0	0	0	0	0	545	0	[illegible]
2025	561	0	0	0	0	0	0	0	0	0	0	0	0	0	561	0	[illegible]
2026	201	0	0	0	0	0	0	0	0	0	0	0	0	0	201	0	[illegible]
2027	207	0	0	0	0	0	0	0	0	0	0	0	0	0	207	0	[illegible]
2028	214	0	0	0	0	0	0	0	0	0	0	0	0	0	214	0	[illegible]
2029	220	0	0	0	0	0	0	0	0	0	0	0	0	0	220	0	[illegible]

COLUMN NOTES:
COLUMN (2) [illegible] 29.13% OF THE SAME COLUMN [illegible]
(16) [illegible]
(18) COLUMN (16) + COLUMN (17)

[illegible]

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)
FOSSIL FUEL UNITS							
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153 2	28,032	23,716	2,158
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917
WYMAN 4	YARMOUTH, ME	1978	OIL	12 2	2,030	1,806	112
NEWPORT DIESELS	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8 8 8 3 4 1	1,803	1,499	152
NUCLEAR UNITS							
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33 5	170,705	160,949	4,878
MILLSTONE 3	WATERFORD, CT	1986	NUCLEAR	45 9	137,749	128,279	4,735
VERMONT YANKEE	BRATTLEBORO, VT		NUCLEAR	12 0	3,786 (a)	3,092	347
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31 6	7,439 (a)	6,105	667
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604	
	- NET INVESTMENT IN SOMERSET UNIT 5				5,860	6,449	(b)
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610	
			TOTAL	542 6	401,659	370,316	15,966

(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)

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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)
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY
- LIABILITY	(14,583)	(8,717)	(2,933)	FERC RATEMAKING POLICY
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)	FAS 87
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY
UNAMORTIZED ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY
TOTAL REG. ASSETS	27,941	28,343	(202)	

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

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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%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
1999	669	509	1,178	6,686
2000	669	460	1,129	6,017
2001	669	412	1,081	5,349
2002	669	364	1,032	4,680
2003	669	315	984	4,011
2004	669	267	935	3,343
2005	669	218	887	2,674
2006	669	170	838	2,006
2007	669	121	790	1,337
2008	669	73	741	669
2009	669	24	693	(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%
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)

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

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
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

(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
1999	621	328	3,102	318	711	2,306	7,386
2000	639	339	3,058	407	713	1,206	6,362
2001	658	349	2,972	408	716	58	5,161
2002	679	359	2,906	409	718	60	5,131
2003	699	370	2,823	456	803	63	5,214
2004	721	382	2,742	457	983	65	5,350
2005	743	394	2,681	585	986	68	5,457
2006	766	405	2,587	587	990	70	5,405
2007	770	409	2,013	578	967	52	4,789
2008	759	406	0	546	510	0	2,221
2009	782	418	0	546	0	0	1,746
2010	806	431	0	710	0	0	1,947
2011	830	444	0	710	0	0	1,984
2012	855	457	0	177	0	0	1,489
2013	880	471	0	0	0	0	1,351
2014	907	485	0	0	0	0	1,392
2015	934	499	0	0	0	0	1,433
2016	962	514	0	0	0	0	1,476
2017	991	530	0	0	0	0	1,521
2018	1,021	546	0	0	0	0	1,567
2019	1,051	562	0	0	0	0	1,613
2020	1,083	579	0	0	0	0	1,662
2021	1,115	596	0	0	0	0	1,711
2022	1,149	614	0	0	0	0	1,763
2023	1,183	633	0	0	0	0	1,816
2024	1,219	652	0	0	0	0	1,871
2025	1,255	671	0	0	0	0	1,926
2026	0	691	0	0	0	0	691
2027	0	712	0	0	0	0	712
2028	0	733	0	0	0	0	733
2029	0	755	0	0	0	0	755

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Purchase Power Total $000

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	HQ	CMP	BSH	OSP @ 9.75% ROE	Total
1998	36 042	25 977	3 912	330	3 562	25 446	27 471	12 513	526	10 662	150	550	(1 206)	145 955
1999	35 710	27 181	3 976	339	3 566	25 638	27 005	12 519	528	10 770	0	0	(1 146)	146 086
2000	36 174	27 040	4 023	347	3 612	24 978	27 541	12 637	531	10 096	0	0	(1 089)	145 885
2001	36 184	28 546	4 079	361	3 710	25 995	27 914	8 061	533	6 935	0	0	(1 014)	139 788
2002	35 333	21 448	4 137	376	3 818	27 847	27 097	6 380	536	3 731	0	0	(983)	120 720
2003	35 763	0	4 198	391	3 935	25 332	29 839	6 970	539	3 612	0	0	(914)	109 645
2004	34 910	0	4 261	406	4 057	25 953	27 792	7 290	541	3,508	0	0	(887)	107 831
2005	35 889	0	4 327	423	4 192	26 533	27 430	7 907	544	3 397	0	0	(842)	109 800
2006	34 488	0	4 395	440	4 335	26,001	28,508	8 179	547	3 225	0	0	(800)	109 318
2007	36 141	0	4 466	457	4 485	26 907	28 363	8 815	550	3,088	0	0	(760)	112 512
2008	33 952	0	4 540	476	4 643	30 870	27 976	8 937	553	2 997	0	0	(722)	114 222
2009	36 999	0	4 616	495	4 805	27 074	32 561	9 404	557	2 909	0	0	(686)	118 734
2010	34 533	0	4 696	514	4 969	28 398	29 600	9 479	560	2 823	0	0	(652)	114 920
2011	40 427	0	4 779	535	5 146	0	27 329	10 560	563	2 740	0	0	(303)	91 776
2012	19 360	0	4,885	556	5 331	0	0	10 270	567	2,659	0	0	0	43 608
2013	0	0	4 955	579	5 519	0	0	10 413	571	2,581	0	0	0	24 618
2014	0	0	5,049	602	5,717	0	0	10 841	575	2,505	0	0	0	25 289
2015	0	0	5,148	628	0	0	0	11 453	578	2 432	0	0	0	20 235
2016	0	0	5,247	651	0	0	0	11 586	582	2,360	0	0	0	20 426
2017	0	0	0	0	0	0	0	12 384	586	1 988	0	0	0	14 958
2018	0	0	0	0	0	0	0	12 095	591	1 927	0	0	0	14 613
2019	0	0	0	0	0	0	0	12 512	0	1,889	0	0	0	14 381
2020	0	0	0	0	0	0	0	12 769	0	1,584	0	0	0	14 353
2021	0	0	0	0	0	0	0	13 455	0	0	0	0	0	13 455
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

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Purchase Power MWh

	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
1999	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	324,157	2,710,592
2000	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	283,092	2,740,313
2001	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	134,017	2,520,452
2002	553,418	441,228	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	2,310,145
2003	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2004	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2005	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2006	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2007	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2008	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2009	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2010	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2011	482,632	0	36,979	10,234	17,420	0	541,959	194,911	5,453	0	1,289,588
2012	184,473	0	36,979	10,234	17,420	0	0	194,911	5,453	0	449,470
2013	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2014	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2015	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2016	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2017	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2018	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2019	0	0	0	0	0	0	0	194,911	0	0	194,911
2020	0	0	0	0	0	0	0	194,911	0	0	194,911
2021	0	0	0	0	0	0	0	194,911	0	0	194,911
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

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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
1999	1,663	1,234	1,555	4,452
2000	0	815	1,555	2,370
2001	0	0	1,555	1,555
2002	0	0	1,555	1,555
2003	0	0	1,555	1,555
2004	0	0	1,555	1,555
2005	0	0	1,555	1,555
2006	0	0	1,555	1,555
2007	0	0	1,555	1,555
2008	0	0	1,555	1,555
2009	0	0	1,555	1,555
2010	0	0	1,555	1,555
2011	0	0	1,555	1,555
2012	0	0	1,555	1,555
2013	0	0	1,555	1,555
2014	0	0	1,555	1,555
2015	0	0	1,555	1,555
2016	0	0	1,555	1,555
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

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

	SEABROOK	MILLSTONE	CANAL 2	WYMAN 4	MAINE YNK	VERMONT YNK	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	297	138	527	91	214	55	1,322
1999	292	138	507	91	214	55	1,297
2000	286	138	488	91	214	55	1,272
2001	280	138	470	91	214	55	1,248
2002	275	138	452	91	214	55	1,225
2003	269	138	435	91	238	61	1,232
2004	264	138	418	91	238	61	1,210
2005	259	138	402	91	238	61	1,189
2006	254	138	386	91	238	61	1,168
2007	249	138	371	91	238	61	1,148
2008	245	138	357	91	238	61	1,130
2009	240	138	443	91	0	61	973

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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
1999	29,236	24,802	1,178	55,216	0	55,216
2000	27,038	29,844	1,129	58,011	0	58,011
2001	25,074	18,679	1,081	44,834	0	44,834
2002	23,200	27,503	1,032	51,735	0	51,735
2003	20,758	33,525	984	55,267	0	55,267
2004	17,868	39,196	935	57,999	0	57,999
2005	14,848	36,936	887	52,671	0	52,671
2006	11,711	42,265	838	54,814	0	54,814
2007	8,475	39,490	790	48,756	0	48,756
2008	5,105	45,788	741	51,635	0	51,635
2009	1,650	41,723	693	44,066	0	44,066

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

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

YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BOOK BASIS BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	TAX BASIS 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
1999	329,715	25,236	354,951	60,728	0	60,728	294,223	115,409
2000	301,993	23,114	325,106	55,622	0	55,622	269,484	105,705
2001	284,641	21,786	306,427	52,426	0	52,426	254,001	99,632
2002	259,093	19,830	278,924	47,721	0	47,721	231,203	90,689
2003	227,952	17,447	245,398	41,985	0	41,985	203,414	79,789
2004	191,543	14,660	206,203	35,279	0	35,279	170,924	67,045
2005	157,233	12,034	169,267	28,960	0	28,960	140,307	55,036
2006	117,972	9,029	127,001	21,728	0	21,728	105,273	41,293
2007	81,289	6,222	87,511	14,972	0	14,972	72,539	28,453
2008	38,757	2,966	41,723	7,138	0	7,138	34,585	13,566
2009	(0)	(0)	(0)	(0)	0	(0)	(0)	(0)

COLUMN NOTES:
(2) SEE SCHEDULE 1, P. 4 COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, P. 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.

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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
1999	354,951	115,409	239,542	247,911	28,109	1,128	29,236
2000	325,106	105,705	219,401	229,471	26,018	1,020	27,038
2001	306,427	99,632	206,795	213,098	24,161	913	25,074
2002	278,924	90,689	188,234	197,515	22,395	806	23,200
2003	245,398	79,789	165,609	176,922	20,060	698	20,758
2004	206,203	67,045	139,158	152,384	17,278	591	17,868
2005	169,267	55,036	114,231	126,695	14,365	483	14,848
2006	127,001	41,293	85,708	99,970	11,335	376	11,711
2007	87,511	28,453	59,058	72,383	8,207	269	8,475
2008	41,723	13,566	28,157	43,607	4,944	161	5,105
2009	(0)	(0)	(0)	14,078	1,596	54	1,650

EECo 12/31/95
CAPITAL STRUCTURE

			ATWACC	BTWACC
COMMON	48 45%	9 20% (a)	4 46%	7 33%
PFD	5 95%	9.83%	0 58%	0 96%
LTD	45 60%	6 67%	3 04%	3 04%
	100 00%		8 08%	11 338%
TAX RATE				39 225%

COLUMN NOTES
(2) SEE SCHEDULE 1, P 13 COLUMN (4)
(3) SEE SCHEDULE 1, P 13 COLUMN (9)
(4) COLUMN (2) - COLUMN (3)
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2
(6) COLUMN (5) x TOTAL RATE OF RETURN
(7) AVERAGE UNAMORT. ITC (ASSUMING 12 YR SL AMORT OF P. 5, COLUMN (2) * BTWACC)
(8) COLUMN (6) + COLUMN (7)
(a) PER NEP RI FILING

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

YEAR END (1)	NUCLEAR DECOMMISS AND OTHER POST SHUTDOWN COSTS (2)	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 TRANSPORT COSTS (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)	PURTOR 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
1999	7 386	148 086	71 160	74 926	0	(4 452)	0	(4 452)	451	1,297	0	0	0	0	79,608
2000	6 362	145 885	72 628	73 257	0	(2 370)	0	(2,370)	430	1,272	0	0	0	0	78,951
2001	5 161	139 288	65 306	73 987	0	(1,555)	0	(1 555)	410	1 248	0	0	0	0	79,246
2002	5 131	129 720	66 390	63 330	0	(1 555)	0	(1 555)	373	1,225	0	0	0	0	68,504
2003	5 214	109 645	53,329	56,316	0	(1,555)	0	(1 555)	346	1,232	0	0	0	0	61,553
2004	5 350	107 831	57 331	50 500	0	(1 555)	0	(1 555)	319	1,210	0	0	0	0	55,824
2005	5 457	109 800	56 820	52 980	0	(1 555)	0	(1 555)	291	1 189	0	0	0	0	58,362
2006	5 405	109 318	60 784	48 534	0	(1 555)	0	(1 555)	264	1 168	0	0	0	0	53,816
2007	4 789	112 512	60 369	52 143	0	(1 555)	0	(1 555)	237	1,148	0	0	0	0	56,762
2008	2 221	114 222	65,139	49,083	0	(1,555)	0	(1 555)	209	1,130	0	0	0	0	51,088
2009	1,746	118 734	64,362	54 372	0	(1,555)	0	(1 555)	182	973	0	0	0	0	55,718
2010	1 947	114 920	69 338	45,582	0	(1 555)	0	(1 555)	155	0	0	0	0	0	46,128
2011	1 984	91 776	49 040	42,736	0	(1 555)	0	(1,555)	37	0	0	0	0	0	43,202
2012	1 489	43 608	17 737	25 871	0	(1,555)	0	(1,555)	0	0	0	0	0	0	25,805
2013	1 351	24 618	10 724	13,894	0	(1 555)	0	(1,555)	0	0	0	0	0	0	13,690
2014	1 392	25,289	10 962	14,327	0	(1,555)	0	(1 555)	0	0	0	0	0	0	14,184
2015	1 433	20 235	10 492	9,743	0	(1 555)	0	(1 555)	0	0	0	0	0	0	9,621
2016	1 476	20,426	10 879	9 547	0	(1,555)	0	(1 555)	0	0	0	0	0	0	9,468
2017	1 521	14 956	9 131	5,825	0	0	0	0	0	0	0	0	0	0	7,346
2018	1 567	14,613	9 319	5 294	0	0	0	0	0	0	0	0	0	0	6,861
2019	1 613	14 381	9 066	5 315	0	0	0	0	0	0	0	0	0	0	6,926
2020	1 662	14 353	8 860	5 493	0	0	0	0	0	0	0	0	0	0	7,155
2021	1 711	13 455	8,996	4 459	0	0	0	0	0	0	0	0	0	0	6,170
2022	1 763	0	0	0	0	0	0	0	0	0	0	0	0	0	1,763
2023	1 816	0	0	0	0	0	0	0	0	0	0	0	0	0	1,816
2024	1 871	0	0	0	0	0	0	0	0	0	0	0	0	0	1,871
2025	1 926	0	0	0	0	0	0	0	0	0	0	0	0	0	1,926
2026	691	0	0	0	0	0	0	0	0	0	0	0	0	0	691
2027	712	0	0	0	0	0	0	0	0	0	0	0	0	0	712
2028	733	0	0	0	0	0	0	0	0	0	0	0	0	0	733
2029	755	0	0	0	0	0	0	0	0	0	0	0	0	0	755

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

[illegible]

SCHEDULE 2

CALCULATION OF ADJUSTMENT FOR DEFERRAL OF CONTRACT TERMINATION DATE

BVE

IMPACT OF CONTRACT TERMINATION DEFERRAL
ON STARTING BALANCE OF SUNK COMMITMENTS
MONTAUP ELECTRIC COMPANY
($ IN 000's)

Schedule 2
Page 1 of 3

	1998	
CONTINUATION OF CURRENT RECOVERY		
DEPRECIATION OF GEN. PL ANT	15,966 (a)	1,331
AMORTIZATION OF REG ASSETS	332 (b)	28
TOTAL	16,298	1,358
AMORT PER CTC		
TOTAL	19,575 (c)	1,631
EXCESS AMORTIZATION	(3,277)	(273)
CUMULATIVE EXCESS AMORT.	(3,277)	(273)
	1999	
CONTINUATION OF CURRENT RECOVERY		
DEPRECIATION OF GEN. PL ANT	15,966 (a)	1,331
AMORTIZATION OF REG ASSETS	19 (b)	2
TOTAL	15,985	1,332
AMORT PER CTC		
TOTAL	25,470 (c)	2,123
EXCESS AMORTIZATION	(9,485)	(790)
CUMULATIVE EXCESS AMORT.	(12,763)	(1,064)
	2000	
CONTINUATION OF CURRENT RECOVERY		
DEPRECIATION OF GEN. PL ANT	15,966 (a)	1,331
AMORTIZATION OF REG ASSETS	(180)(b)	(15)
TOTAL	15,786	1,316
AMORT PER CTC		
TOTAL	30,513 (c)	2,543
EXCESS AMORTIZATION	(14,727)	(1,227)
CUMULATIVE EXCESS AMORT.	(27,489)	(2,291)

531,000

(a) Schedule 1, p. 4, Column (8)
(b) Schedule 1, p. 5, Column (3) + Schedule 1, p. 5a, Amortization Amount (1996 & Beyond)
(c) Schedule 1, p. 12, Column (3) + Schedule 1, p. 5a, Column (1)

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Schedule 2
Page 3 of 3

RECONCILIATION ADJUSTMENT ILLUSTRATION CALCULATION
BLACKSTONE VALLEY ELECTRIC SHARE

	ADJUSTMENTS TO MONTAUP ELECTRIC COMPANY COSTS		BLACKSTONE VALLEY 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 (4)	DEFERRAL OF CONTRACT TERM DATE (5)	CREDIT FOR DIFF BETWEEN 9.20%ROE & 11.4% ROE (6)	BUYOUT SAVINGS (8)	ANNUAL SHORTFALL/ (EXCESS) (7)	ANNUAL PRE TAX RETURN ON BALANCE (8)	COLLECTION OF PRIOR YR BAL INCL INTEREST (9)	END OF YR ACCOUNT BALANCE (10)
1997								0	0	0	0
1998	0	0	0	0	0	0	0	0	0	0	0
1999	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

COLUMN NOTES
(2) ASSUMED TO BE ZERO
(3) TO BE DETERMINED AT VALUATION
(4) SEE SCHEDULE 2, PG 2, COLUMN (23) X -1
(5) COLUMN (2) x BLACKSTONE'S % OF SALES
(6) COLUMN (3) x BLACKSTONE'S % OF SALES
(7) SUM OF COLUMN (4) THROUGH (6)
(8) COLUMN (10) PRIOR YEAR x RETURN @ BTWACC
(9) COLUMN (10) PRIOR YEAR x -1 COLUMN (8) CURRENT YEAR
(10) PRIOR YEAR COLUMN (10) + CURRENT YEAR SUM COLUMN (7) THROUGH (9)

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APPENDIX 1

FORMULA FOR CALCULATING CONTRACT TERMINATION CHARGES

RI (Newport)

12/5/97
SMD

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 Maine Yankee and Vermont Yankee Units, 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;
(v) Unamortized ITC; and
(vi) 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

[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.

facilities ("Divestiture Date")[3], and sufficient to provide an overall pretax return 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, excluding the unamortized ITC under 1.1.1(b)(v), 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

---

[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.

[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, and the difference between the 11.34 percent and 13.09 percent returns that occurs after the Divestiture Date shall be included in the Reconciliation Account. The 11.34 percent and 13.09 percent returns shall be used as the return wherever a return is referenced throughout this Appendix. However, the 13.09 percent return after the Divestiture Date shall be adjusted in accordance with Section 1.1.4(d). 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.

(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 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

[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.

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 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 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.

[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.

(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,[2] the cost of which is 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 Newport shall be calculated as follows:

(i) Newport's 11.85 percent allocated share of Total Proceeds[3]

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[2] 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.

[3] 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

equal to the sale price and other consideration received by Montaup excluding $15 million[2] which purchasers will be required to pay into an account for employee benefits pursuant to Section 1.2.2(f), 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 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

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.

[2] This figure consists of $11.8 million as shown on Schedule 5 and an estimated $3.2 million for Canal 2 based on Montaup's 25% share of employee costs for Canal Station. The parties agree to use a reasonable actual figure for Canal 2 when available from Canal Electric.

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.[10] 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.

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

[10] 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.

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 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.

The Reconciliation Account shall accumulate through December 31, 2000, and shall be used to adjust Montaup's Base Contract Termination Charges to Newport on January 1, 2001. Thus, effective January 1, 2001, 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. Thereafter, 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. Any Reconciliation Account adjustments occurring prior to January 1, 2001 that would otherwise cause the Contract

Termination Charge to increase or decrease by more than 0.2 cents per kilowatthour shall be implemented up to 0.2 cents per kilowatthour. The excess above 0.2 cents per kilowatthour shall be amortized with a return over the three years following January 1, 2001.

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 and Connecticut 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) Above Market Payments to Power Suppliers 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, Connecticut Yankee, Maine Yankee, 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. Montaup shall require purchasers of its generating assets to pay $15 million[11] for the costs under this paragraph incurred by Montaup or its affiliates. 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

[11] The parties agree that $11.8 million will be resrved 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 avilable from Canal Electric.

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 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, 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,[12] 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

[12] 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.

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 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).

SCHEDULE 1

SUMMARY OF CONTRACT TERMINATION CHARGES

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

Schedule1
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 TOT TERM CHARGE $ IN 000 (7)	BASE CONTRACT TERM CHARG CENTS/KWH (8)
1998	530,586	6,196	1 17	9,721	1 83	15,918	3 00
1999	536,555	6,663	1 24	9,434	1 76	16,097	3 00
2000	544,130	6,968	1 28	9,356	1.72	16,324	3.00
2001	549,613	5,350	0 97	9,391	1 71	14,741	2 68
2002	555,606	6,156	1 11	8,118	1 46	14,274	2 57
2003	563,367	6,569	1 17	7,294	1 29	13,863	2 46
2004	571,358	6,853	1 20	6,615	1 16	13,468	2 36
2005	580,288	6,186	1 07	6,916	1.19	13,102	2 26
2006	589,480	6,372	1 08	6,377	1 08	12,749	2 16
2007	596,369	5,628	0 94	6,726	1 13	12,354	2 07
2008	603,135	5,914	0 98	6,054	1 00	11,968	1 98
2009	609,079	4,974	0 82	6,603	1 08	11,577	1.90
2010	616,061	0	0 00	5,466	0 89	5,466	0 89
2011	622,439	0	0 00	5,119	0 82	5,119	0 82
2012	627,545	0	0 00	3,058	0 49	3,058	0 49
2013	636,621	0	0 00	1,622	0 25	1,622	0 25
2014	643,741	0	0 00	1,678	0 26	1,678	0 26
2015	649,276	0	0 00	1,140	0 18	1,140	0 18
2016	654,269	0	0 00	1,122	0 17	1,122	0.17
2017	661,599	0	0 00	870	0 13	870	0 13
2018	667,717	0	0 00	813	0 12	813	0.12
2019	673,767	0	0 00	821	0 12	821	0 12
2020	680,723	0	0 00	848	0 12	848	0 12
2021	687,311	0	0 00	731	0 11	731	0 11
2022	694,002	0	0 00	209	0 03	209	0 03
2023	700,796	0	0 00	215	0 03	215	0 03
2024	707,697	0	0 00	222	0.03	222	0 03
2025	714,705	0	0 00	228	0 03	228	0 03
2026	·721,821	0	0 00	82	0 01	82	0 01
2027	757,912	0	0 00	84	0 01	84	0 01
2028	795,808	0	0 00	87	0 01	87	0 01
2029	835,598	0	0 00	89	0 01	89	0 01

COLUMN NOTES
(2) PER 1996 LONG RANGE ENERGY & DEMAND FORECAST
(3) SCHEDULE 1, P2, COLUMN (8).
(4) COLUMN (3)/COLUMN (2)
(5) SEE SCHEDULE 1, P 3, COLUMN (18)
(6) COLUMN (5)/COLUMN (2)
(7) COLUMN (3) + COLUMN (5)
(8) COLUMN (7)/COLUMN (2)

NP30BAS2 WK4 10/23/97

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
1999	3,449	3,075	140	6,663	0	6,663
2000	3,178	3,656	134	6,968	0	6,968
2001	2,938	2,284	128	5,350	0	5,350
2002	2,711	3,323	122	6,156	0	6,156
2003	2,417	4,036	117	6,569	0	6,569
2004	2,071	4,671	111	6,853	0	6,853
2005	1,712	4,369	105	6,186	0	6,186
2006	1,344	4,928	99	6,372	0	6,372
2007	968	4,566	94	5,628	0	5,628
2008	580	5,247	88	5,914	0	5,914
2009	186	4,706	82	4,974	0	4,974

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

NP30BAS2.WK4 10/23/97

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

YEAR END (1)	NUCLEAR DECOMMISS AND OTHER POST SHUTDOWN COSTS (2)	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)	ASSUMED MARKET VALUE (8)	NET EXCESS OVER MARKET (9)	ABOVE MARKET FUEL TRANSPORT COSTS (10)	TRANSMISSION [illegible] (11)	[illegible] TAXES (12)	EMPLOYEE SEVERANCE AND RETRAINING COSTS (13)	DAMAGES COSTS [illegible] CLAIMS (14)	[illegible] VALUATION (15)	BASE TOTAL VARIABLE COMPONENT (16)	[illegible] (17)	TOTAL VARIABLE COMPONENT [illegible] (18)
1998	949	17 298	8 161	9 134	0	(575)	0	(575)	56	152	0	0	0	0	9 721	0	9 721
1999	875	17 311	8 432	8 879	0	(520)	0	(520)	53	154	0	0	0	0	9 434	0	9 434
2000	754	17 287	8 606	8 681	0	(281)	0	(281)	51	151	0	0	0	0	9 356	0	9 356
2001	612	16 508	7 739	8 767	0	(184)	0	(184)	49	148	0	0	0	0	9 391	0	9 391
2002	608	15 472	7 867	7 505	0	(184)	0	(184)	44	145	0	0	0	0	8 118	0	8 118
2003	618	12 991	6 319	6 671	0	(184)	0	(184)	41	148	0	0	0	0	7 294	0	7 294
2004	634	12 778	6 794	5 984	0	(184)	0	(184)	38	143	0	0	0	0	6 615	0	6 615
2005	647	15 011	6 733	8 278	0	(184)	0	(184)	34	141	0	0	0	0	8 916	0	8 916
2006	640	12 954	7 203	5 751	0	(184)	0	(184)	31	138	0	0	0	0	6 377	0	6 377
2007	567	13 333	7 154	6 179	0	(184)	0	(184)	28	136	0	0	0	0	6 720	0	6 720
2008	263	13 535	7 718	5 818	0	(184)	0	(184)	25	134	0	0	0	0	6 054	0	6 054
2009	207	14 070	7 627	6 443	0	(184)	0	(184)	22	115	0	0	0	0	6 603	0	6 603
2010	231	11 618	6 217	5 401	0	(184)	0	(184)	18	0	0	0	0	0	5 466	0	5 466
2011	235	10 875	5 811	5 064	0	(184)	0	(184)	4	0	0	0	0	0	5 119	0	5 119
2012	178	5 166	2 102	3 064	0	(184)	0	(184)	0	0	0	0	0	0	3 058	0	3 058
2013	190	2 917	1 271	1 646	0	(184)	0	(184)	0	0	0	0	0	0	1 652	0	1 652
2014	185	2 997	1 299	1 698	0	(184)	0	(184)	0	0	0	0	0	0	1 699	0	1 699
2015	170	2 397	1 243	1 154	0	(184)	0	(184)	0	0	0	0	0	0	1 140	0	1 140
2016	175	2 420	1 289	1 131	0	(184)	0	(184)	0	0	0	0	0	0	1 122	0	1 122
2017	180	1 772	1 082	690	0	0	0	0	0	0	0	0	0	0	870	0	870
2018	186	1 732	1 104	627	0	0	0	0	0	0	0	0	0	0	813	0	813
2019	191	1 704	1 074	630	0	0	0	0	0	0	0	0	0	0	821	0	821
2020	197	1 701	1 050	651	0	0	0	0	0	0	0	0	0	0	848	0	848
2021	203	1 594	1 066	528	0	0	0	0	0	0	0	0	0	0	731	0	731
2022	209	0	0	0	0	0	0	0	0	0	0	0	0	0	209	0	209
2023	215	0	0	0	0	0	0	0	0	0	0	0	0	0	215	0	215
2024	222	0	0	0	0	0	0	0	0	0	0	0	0	0	222	0	222
2025	228	0	0	0	0	0	0	0	0	0	0	0	0	0	228	0	228
2026	82	0	0	0	0	0	0	0	0	0	0	0	0	0	82	0	82
2027	84	0	0	0	0	0	0	0	0	0	0	0	0	0	84	0	84
2028	87	0	0	0	0	0	0	0	0	0	0	0	0	0	87	0	87
2029	89	0	0	0	0	0	0	0	0	0	0	0	0	0	89	0	89

COLUMN NOTES
COLUMN (2) THROUGH (10) REPRESENT 11.85% OF THE SAME COLUMN NUMBER ON P. 15
(16) SEE SCHEDULE 2 P. 1 COLUMN (9) X .1
(18) COLUMN (16) + COLUMN (17)

[illegible]

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)
FOSSIL FUEL UNITS							
SOMERSET 6 & JETS	SOMERSET, MA	1959	COAL/JET FUEL	153 2	28,032	23,716	2,158
CANAL 2	SANDWICH, MA	1976	OIL	233	41,041	35,207	2,917
WYMAN 4	YARMOUTH, ME	1978	OIL	12 2	2,030	1,806	112
NEWPORT DIESELS	JAMESTOWN/ PORTSMOUTH, RI/ YARMOUTH, ME	1961 1978 1978	DIESEL DIESEL OIL	8 8 8 3 4 1	1,803	1,499	152
NUCLEAR UNITS							
SEABROOK	SEABROOK, NH	1990	NUCLEAR	33.5	170,705	160,949	4,878
MILLSTONE III	WATERFORD, CT	1986	NUCLEAR	45 9	137,749	128,279	4,735
VERMONT YANKEE	BRATTLEBORO, VT.		NUCLEAR	12 0	3,786 (a)	3,092	347
MAINE YANKEE	BRUNSWICK, ME		NUCLEAR	31.6	7,439 (a)	6,105	667
PLANT HELD FOR FUTURE USE - LAND IN SOMERSET, MA					604	604	
- NET INVESTMENT IN SOMERSET UNIT 5					5,860	6,449	(b)
NONUTILITY PROPERTY (LAND IN PORTSMOUTH, RI & DIGHTON, MA)					2,610	2,610	
			TOTAL	542 6	401,659	370,316	15,966

(a) PLANT IN SERVICE AS OF 12/31/95 INCLUDING FUEL AND 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)

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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 1998 AND BEYOND (3)	BASIS FOR DEFERRAL (4)
FAS 109 - ASSET	39,916	37,466	1,225	FERC RATEMAKING POLICY
- LIABILITY	(14,583)	(8,717)	(2,933)	FERC RATEMAKING POLICY
FAS 106 DEFERRAL	1,313	538	387 (a)	FERC RATEMAKING POLICY
NET PENSION LIABILITY / (ASSET)	(485)	(415)	(35)	FAS 87
UNAMORTIZED DEBT PREMIUMS	13,879	10,665	1,607	FERC RATEMAKING POLICY
UNAMORTIZED ITC	(12,523)	(11,367)	(578)	FERC RATEMAKING POLICY
DREDGING	424	173	125 (b)	FERC RATEMAKING POLICY
TOTAL REG. ASSETS	27,941	28,343	(202)	

(a) REMAINING AMORTIZATION SCHEDULE: 416 IN 1998, 162 IN 1999.
(b) REMAINING AMORTIZATION SCHEDULE: 125 IN 1998, 48 IN 1999.

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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%

	AMORTIZATION (1)	INTEREST (2)	TOTAL EXPENSE (3)	UNAMORTIZED BALANCE (4)
				8,023
1998	669	557	1,226	7,354
1999	669	509	1,178	6,686
2000	669	460	1,129	6,017
2001	669	412	1,081	5,349
2002	669	364	1,032	4,680
2003	669	315	984	4,011
2004	669	267	935	3,343
2005	669	218	887	2,674
2006	669	170	838	2,006
2007	669	121	790	1,337
2008	669	73	741	669
2009	669	24	693	(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%
(3) Column (1) + Column (2)
(4) Prior Year Column (4) - Current Year Column (1)

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

(1)	MILLSTONE 3 (2)	SEABROOK 1 (3)	VERMONT YK (4)	MAINE YK (5)	TOTAL (6)
1998	0	0	0	0	0
1999	0	0	0	0	0
2000	0	0	0	0	0
2001	0	0	0	0	0
2002	0	0	0	0	0
2003	0	0	0	0	0
2004	0	0	0	0	0
2005	0	0	0	0	0
2006	0	0	0	0	0
2007	0	0	0	0	0
2008	0	0	0	0	0
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

	MILLSTONE 3	SEABROOK 1	CONNECTICUT YANKEE	VERMONT YANKEE	MAINE YANKEE	YANKEE ATOMIC	TOTAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1998	602	319	3,868	317	599	2,306	8,011
1999	621	328	3,102	318	711	2,306	7,386
2000	639	339	3,058	407	713	1,206	6,362
2001	658	349	2,972	408	716	58	5,161
2002	679	359	2,906	409	718	60	5,131
2003	699	370	2,823	456	803	63	5,214
2004	721	382	2,742	457	983	65	5,350
2005	743	394	2,681	585	986	68	5,457
2006	766	405	2,587	587	990	70	5,405
2007	770	409	2,013	578	967	52	4,789
2008	759	406	0	546	510	0	2,221
2009	782	418	0	546	0	0	1,746
2010	806	431	0	710	0	0	1,947
2011	830	444	0	710	0	0	1,984
2012	855	457	0	177	0	0	1,489
2013	880	471	0	0	0	0	1,351
2014	907	485	0	0	0	0	1,392
2015	934	499	0	0	0	0	1,433
2016	962	514	0	0	0	0	1,476
2017	991	530	0	0	0	0	1,521
2018	1,021	546	0	0	0	0	1,567
2019	1,051	562	0	0	0	0	1,613
2020	1,083	579	0	0	0	0	1,662
2021	1,115	596	0	0	0	0	1,711
2022	1,149	614	0	0	0	0	1,763
2023	1,183	633	0	0	0	0	1,816
2024	1;219	652	0	0	0	0	1,871
2025	1,255	671	0	0	0	0	1,926
2026	0	691	0	0	0	0	691
2027	0	712	0	0	0	0	712
2028	0	733	0	0	0	0	733
2029	0	755	0	0	0	0	755

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Purchase Power Total $000

	Pilgrim	Canal 1	Potter 2	Cleary	McNeil	OSP 1	OSP 2	NEA	Blackstone Hydro	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	10 862	150	550	(1 206)	145 955
1999	35,710	27 181	3 976	339	3 586	25,638	27,005	12 519	528	10 770	0	0	(1 146)	146 086
2000	36 174	27 040	4 023	347	3 612	24 978	27 541	12 632	531	10 096	0	0	(1 089)	145 885
2001	36 184	28 548	4 079	361	3 710	25,995	27 914	6 063	533	6 935	0	0	(1 034)	139 288
2002	35 333	21,448	4 137	376	3 818	27 847	27,097	6 380	536	3 731	0	0	(983)	129 720
2003	35 763	0	4 198	391	3 935	25 332	29 839	6 970	539	3 612	0	0	(934)	109 645
2004	34 910	0	4 261	408	4 057	25,953	27 792	7 290	541	3 508	0	0	(887)	107 831
2005	35,889	0	4 327	423	4 192	26,533	27 430	7 907	544	3 397	0	0	(842)	109 800
2006	34.488	0	4 395	440	4 335	26,001	28,508	8 179	547	3 225	0	0	(800)	109 318
2007	36 141	0	4 466	457	4 485	26,907	28,363	8 815	550	3 088	0	0	(760)	112 512
2008	33 952	0	4 540	476	4 643	30 870	27,976	8 937	553	2 997	0	0	(722)	114 222
2009	36,999	0	4,618	495	4 805	27,074	32,561	9 404	557	2 909	0	0	(686)	118 734
2010	34.533	0	4 698	514	4 969	28,398	29,600	9 479	560	2 823	0	0	(652)	114 920
2011	40.427	0	4 779	535	5 146	0	27,329	10 560	563	2 740	0	0	(303)	91 776
2012	19,360	0	4 865	556	5,331	0	0	10 270	567	2 659	0	0	0	43 608
2013	0	0	4 955	579	5,519	0	0	10 413	571	2 581	0	0	0	24 818
2014	0	0	5,049	602	5 717	0	0	10 841	575	2 505	0	0	0	25 289
2015	0	0	5,146	626	0	0	0	11 453	578	2 432	0	0	0	20 235
2016	0	0	5,247	651	0	0	0	11 586	582	2,360	0	0	0	20 426
2017	0	0	0	0	0	0	0	12 384	586	1 986	0	0	0	14 956
2018	0	0	0	0	0	0	0	12 095	591	1 927	0	0	0	14 613
2019	0	0	0	0	0	0	0	12 512	0	1,869	0	0	0	14 381
2020	0	0	0	0	0	0	0	12 769	0	1 584	0	0	0	14 353
2021	0	0	0	0	0	0	0	13 455	0	0	0	0	0	13 455
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

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Purchase Power MWh

Schedule 1
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	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
1999	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	324,157	2,710,592
2000	553,418	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	283,092	2,740,313
2001	482,632	588,304	36,979	10,234	17,420	508,543	541,959	194,911	5,453	134,017	2,520,452
2002	553,418	441,228	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	2,310,145
2003	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2004	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2005	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2006	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2007	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2008	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2009	482,632	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,798,131
2010	553,418	0	36,979	10,234	17,420	508,543	541,959	194,911	5,453	0	1,868,917
2011	482,632	0	36,979	10,234	17,420	0	541,959	194,911	5,453	0	1,289,588
2012	184,473	0	36,979	10,234	17,420	0	0	194,911	5,453	0	449,470
2013	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2014	0	0	36,979	10,234	17,420	0	0	194,911	5,453	0	264,997
2015	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2016	0	0	36,979	10,234	0	0	0	194,911	5,453	0	247,577
2017	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2018	0	0	0	0	0	0	0	194,911	5,453	0	200,364
2019	0	0	0	0	0	0	0	194,911	0	0	194,911
2020	0	0	0	0	0	0	0	194,911	0	0	194,911
2021	0	0	0	0	0	0	0	194,911	0	0	194,911
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

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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
1999	1,663	1,234	1,555	4,452
2000	0	815	1,555	2,370
2001	0	0	1,555	1,555
2002	0	0	1,555	1,555
2003	0	0	1,555	1,555
2004	0	0	1,555	1,555
2005	0	0	1,555	1,555
2006	0	0	1,555	1,555
2007	0	0	1,555	1,555
2008	0	0	1,555	1,555
2009	0	0	1,555	1,555
2010	0	0	1,555	1,555
2011	0	0	1,555	1,555
2012	0	0	1,555	1,555
2013	0	0	1,555	1,555
2014	0	0	1,555	1,555
2015	0	0	1,555	1,555
2016	0	0	1,555	1,555
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

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

(1)	SEABROOK (2)	MILLSTONE (3)	CANAL 2 (4)	WYMAN 4 (5)	MAINE YNK (6)	VERMONT YNK (7)	TOTAL (8)
1998	297	138	527	91	214	55	1,322
1999	292	138	507	91	214	55	1,297
2000	286	138	488	91	214	55	1,272
2001	280	138	470	91	214	55	1,248
2002	275	138	452	91	214	55	1,225
2003	269	138	435	91	238	61	1,232
2004	264	138	418	91	238	61	1,210
2005	259	138	402	91	238	61	1,189
2006	254	138	386	91	238	61	1,168
2007	249	138	371	91	238	61	1,148
2008	245	138	357	91	238	61	1,130
2009	240	138	443	91	0	61	973

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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
1999	29,101	25,950	1,178	56,229	0	56,229
2000	26,821	30,854	1,129	58,803	0	58,803
2001	24,796	19,273	1,081	45,149	0	45,149
2002	22,878	28,040	1,032	51,950	0	51,950
2003	20,395	34,059	984	55,437	0	55,437
2004	17,477	39,416	935	57,828	0	57,828
2005	14,451	36,865	887	52,203	0	52,203
2006	11,342	41,588	838	53,768	0	53,768
2007	8,169	38,536	790	47,494	0	47,494
2008	4,894	44,274	741	49,909	0	49,909
2009	1,573	39,711	693	41,977	0	41,977

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

NP30BAS2.WK4 10/23/97

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

YEAR END (1)	BALANCE NET BOOK VALUE OF GENERATION (2)	BOOK BASIS BALANCE GENERATION RELATED REG. ASSETS (3)	TOTAL NET BOOK BASIS (4)	BALANCE NET TAX VALUE OF GENERATION (5)	TAX BASIS 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
1999	327,546	25,069	352,615	60,328	0	60,328	292,287	114,649
2000	298,886	22,876	321,762	55,050	0	55,050	266,712	104,618
2001	280,983	21,506	302,489	51,752	0	51,752	250,736	98,351
2002	254,937	19,512	274,449	46,955	0	46,955	227,494	89,235
2003	223,300	17,091	240,391	41,128	0	41,128	199,263	78,161
2004	186,686	14,288	200,975	34,384	0	34,384	166,590	65,345
2005	152,442	11,667	164,109	28,077	0	28,077	136,032	53,359
2006	113,810	8,711	122,521	20,962	0	20,962	101,559	39,837
2007	78,015	5,971	83,986	14,369	0	14,369	69,617	27,307
2008	36,888	2,823	39,711	6,794	0	6,794	32,917	12,912
2009	0	0	0	0	0	0	0	0

COLUMN NOTES:
(2) SEE SCHEDULE 1, P. 4 COLUMN (7) FOR 1997 BALANCE.
(3) SEE SCHEDULE 1, P. 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.

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

Schedule 1
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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
1999	352,615	114,649	237,966	246,722	27,974	1,128	29,101
2000	321,762	104,618	217,144	227,555	25,801	1,020	26,821
2001	302,489	98,351	204,137	210,641	23,883	913	24,796
2002	274,449	89,235	185,215	194,676	22,073	806	22,878
2003	240,391	78,161	162,230	173,722	19,697	698	20,395
2004	200,975	65,345	135,630	148,930	16,886	591	17,477
2005	164,109	53,359	110,751	123,190	13,967	483	14,451
2006	122,521	39,837	82,685	96,718	10,966	376	11,342
2007	83,986	27,307	56,678	69,682	7,901	269	8,169
2008	39,711	12,912	26,799	41,739	4,732	161	4,894
2009	0	0	0	13,400	1,519	54	1,573

EECo 12/31/95

CAPITAL STRUCTURE			ATWACC	BTWACC
COMMON	48.45%	9.20% (a)	4.46%	7.33%
PFD	5.95%	9.83%	0.58%	0.96%
LTD	45.60%	6.67%	3.04%	3.04%
	100.00%		8.08%	11.338%
TAX RATE				39.225%

COLUMN NOTES:
(2) SEE SCHEDULE 1, P 13 COLUMN (4)
(3) SEE SCHEDULE 1, P 13 COLUMN (9)
(4) COLUMN (2) - COLUMN (3)
(5) COLUMN (4) PRIOR YEAR+COLUMN (4)/2
(6) COLUMN (5) x TOTAL RATE OF RETURN
(7) AVERAGE UNAMORT ITC (ASSUMING 12 YR S/L AMORT OF P. 5, COLUMN (2) * BTWACC)
(8) COLUMN (6) + COLUMN (7)
(a) PER NEP RI FILING

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

YEAR END (1)	NUCLEAR DECOMMISS 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 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)	PRR 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
1999	7,386	146,086	71,160	74,926	0	(4,452)	0	(4,452)	451	1,297	0	0	0	0	79,608
2000	6,362	145,885	72,628	73,257	0	(2,370)	0	(2,370)	430	1,272	0	0	0	0	78,951
2001	5,161	139,288	65,306	73,982	0	(1,555)	0	(1,555)	410	1,248	0	0	0	0	79,246
2002	5,131	129,720	66,390	63,330	0	(1,555)	0	(1,555)	373	1,225	0	0	0	0	68,504
2003	5,214	109,645	53,329	56,316	0	(1,555)	0	(1,555)	346	1,232	0	0	0	0	61,553
2004	5,350	107,831	57,331	50,500	0	(1,555)	0	(1,555)	319	1,210	0	0	0	0	55,824
2005	5,457	109,800	56,820	52,980	0	(1,555)	0	(1,555)	291	1,189	0	0	0	0	58,362
2006	5,405	109,318	60,784	48,534	0	(1,555)	0	(1,555)	264	1,168	0	0	0	0	53,816
2007	4,789	112,512	60,369	52,143	0	(1,555)	0	(1,555)	237	1,148	0	0	0	0	56,762
2008	2,221	114,222	65,139	49,083	0	(1,555)	0	(1,555)	209	1,130	0	0	0	0	51,088
2009	1,746	118,734	64,362	54,372	0	(1,555)	0	(1,555)	187	973	0	0	0	0	55,718
2010	1,947	114,920	69,338	45,582	0	(1,555)	0	(1,555)	155	0	0	0	0	0	46,128
2011	1,984	91,776	49,040	42,738	0	(1,555)	0	(1,555)	37	0	0	0	0	0	43,202
2012	1,489	43,608	17,737	25,871	0	(1,555)	0	(1,555)	0	0	0	0	0	0	25,805
2013	1,351	24,618	10,724	13,894	0	(1,555)	0	(1,555)	0	0	0	0	0	0	13,690
2014	1,392	25,289	10,962	14,327	0	(1,555)	0	(1,555)	0	0	0	0	0	0	14,164
2015	1,433	20,235	10,492	9,743	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,621
2016	1,478	20,426	10,879	9,547	0	(1,555)	0	(1,555)	0	0	0	0	0	0	9,468
2017	1,521	14,956	9,131	5,825	0	0	0	0	0	0	0	0	0	0	7,346
2018	1,567	14,613	9,319	5,294	0	0	0	0	0	0	0	0	0	0	6,861
2019	1,613	14,381	9,066	5,315	0	0	0	0	0	0	0	0	0	0	6,928
2020	1,662	14,353	8,860	5,493	0	0	0	0	0	0	0	0	0	0	7,155
2021	1,711	13,455	8,996	4,459	0	0	0	0	0	0	0	0	0	0	6,170
2022	1,763	0	0	0	0	0	0	0	0	0	0	0	0	0	1,763
2023	1,818	0	0	0	0	0	0	0	0	0	0	0	0	0	1,818
2024	1,871	0	0	0	0	0	0	0	0	0	0	0	0	0	1,871
2025	1,926	0	0	0	0	0	0	0	0	0	0	0	0	0	1,926
2026	691	0	0	0	0	0	0	0	0	0	0	0	0	0	691
2027	712	0	0	0	0	0	0	0	0	0	0	0	0	0	712
2028	733	0	0	0	0	0	0	0	0	0	0	0	0	0	733
2029	755	0	0	0	0	0	0	0	0	0	0	0	0	0	755

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

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SCHEDULE 2

CALCULATION OF ADJUSTMENT FOR DEFERRAL OF CONTRACT TERMINATION DATE

RECONCILIATION ADJUSTMENT ILLUSTRATION CALCULATION
NEWPORT ELECTRIC SHARE

[illegible]

Schedule 2
Page 3 of 3

RECONCILIATION ADJUSTMENT ILLUSTRATION 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 9 083%ROE & 11 4% ROE (3)	VARIABLE RECONCIL ADJUSTMENT (4)	DEFERRAL OF CONTRACT TERM DATE (5)	CREDIT FOR DIFF BETWEEN 9 083%ROE & 11 4% ROE (6)	ANNUAL SHORTFALL/ (EXCESS) (7)	ANNUAL PRE-TAX RETURN ON BALANCE (8)	COLLECTION OF PRIOR YR BAL INCL INTEREST (9)	END OF YR ACCOUNT BALANCE (10)
1997						0	0	0	0
1998	0	0	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0

COLUMN NOTES
(2) ASSUMED TO BE ZERO
(3) TO BE DETERMINED AT VALUATION
(4) SEE SCHEDULE 2, PG 2, COLUMN (23) X -1
(5) COLUMN (2) x NEWPORT'S % OF SALES
(6) COLUMN (3) x NEWPORT'S % OF SALES
(7) SUM OF COLUMN (4) THROUGH (6)
(8) COLUMN (10) PRIOR YEAR x RETURN @ BTWACC
(9) COLUMN (10) PRIOR YEAR x -1- COLUMN (8) CURRENT YEAR
(10) PRIOR YEAR COLUMN (10) + CURRENT YEAR SUM COLUMNS (7) THROUGH (9)

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PUC 2-9

Request:

Referencing the $10.4 million credit presented on Bates page 97, please describe the types of costs/revenues/credits that were incurred/received by NEP from which the $10.4 is derived and provide an explanation and schedule showing how the $10.4 million credit owed to Narragansett Electric was calculated pursuant to the CTC by NEP.

Response:

The $10.4 million credit consists of $1.6 million in excess revenues compared to estimates, and Narragansett Electric's share of NEP's following actual to estimated expense under/overs:

- $6.8 million credit for Nuclear Decommissioning and Other Post Shut-Down Costs. There were no cost estimates for the Connecticut Yankee, Maine Yankee, and Yankee Atomic Power nuclear units in calendar year 2011 and onwards. The actual costs charged by the Yankees included NEP's share of the costs associated with interim onsite storage of spent nuclear fuel and nuclear waste from the decommissioned power plants. These costs have been reduced by, and reflect proceeds paid to NEP, if any, associated with litigation awards received by the Yankees from the US Department of Energy (DOE). The litigation was for the DOE's failure to remove the Yankees' respective spent nuclear fuel stores and nuclear waste as required by the Nuclear Waste Policy Act of 1982 and contracts between the Yankees and the DOE.

- $13.4 million credit for Power Contracts. The Actual Power Contract Obligations and Market Value relate to NEP's share of the costs and revenues associated with the Hydro Quebec Phase I and Phase II transmission interconnection facilities. The Hydro- Quebec Phase I/II Interconnection facilities were developed as regional participant-funded transmission projects in the mid-1980s and consist of the United States portion of the 2,000 MW (nominal) High-Voltage Direct Current transmission facilities interconnecting the transmission systems operated by ISO New England Inc. ("ISO-NE") and Hydro-Québec TransÉnergie. The costs associated with this contract include support payments for the operation and maintenance of those facilities. Revenues for the use of these transmission facilities are derived by re-selling NEP's share of transmission use rights of the facilities. In addition, NEP receives its allocated share of the benefits under the ISO-NE Transmission, Markets, and Services Tariff (Hydro-Québec Interconnection Capability Credits) that serve as an off-set against its capacity obligations in the ISO-NE markets.

- $481,000 credit for Nuclear PBR business continuity (NEIL) credits for insurance policies held on NEP properties. The Nuclear PBR was initially estimated as zero in the original CTC settlement (Compiled Settlement, p. 233). Per the Settlement (Compiled Settlement, pp. 211-212), 80 percent of the net costs or income are recovered from or returned to customers.

- $190,000 credit for Vermont Yankee ongoing administrative services. The Vermont Yankee offering set the terms of the sale of the unit as a sale of assets only, with the Vermont Yankee Nuclear Power Corporation ("VYNPC") surviving to administer the existing, albeit-amended, wholesale purchased power contracts. VYNPC entered into a power purchase agreement with the new owner of the plant and sold the power to the original equity owners under the existing Vermont Yankee contracts. The power component assignment to a third party did not include the ongoing overhead and administrative costs of VYNPC.

- $9,000 for Environmental Response Costs. NEP remains liable for the estimated costs of one site located in Beverly, Massachusetts. Environmental Response Costs are collected from customers as incurred and are recoverable through the CTC pursuant to section 1.2.2 (i) of the CTC formula.

The impact of these costs/revenues/credits on the $10.4 million credit owed to Narragansett Electric Company is illustrated in Attachment PUC-2-9, which provides summary reconciliation schedules of The Narragansett Electric Company ("Narragansett"), the former Blackstone Valley Electric Company ("Blackstone"), and the former Newport Electric Corporation ("Newport"). Page 1 of the attachment provides a high-level overview of the CTC rate calculation. Page 2 provides an illustrative example of how that calculation applies to Narragansett's, Blackstone's, and Newport's respective summary reconciliation schedules on Pages 3 through 5. The reconciliation adjustment begins with a true-up of the previous year's October through December estimates. The prior end of year account balance from the previous filing is shown on Line 1 and the prior year return is reversed on Line 2. Then the estimated vs actual revenues and expenses shown on Lines 4 through 7 and the recalculated return on the balance shown on Line 8 are added to or subtracted from the original prior year end balance to calculate a new prior year end account balance. These steps are then rolled forward for January through September actuals in the current year on Lines 10 through 17 to calculate the current year end account balance at September 30 on Line 18. Estimates for the following year roll the balance forward again on Lines 19 and 20, arriving at the collection of prior year balance including interest on Line 21, which is then divided by the following year's estimated kilowatt-hours contained in the CTC settlement on Line 22 to arrive at the new CTC rate as shown on Line 23. The $10.4 million

PUC 2-9, page 3

credit is comprised of Narragansett's $7.0 million credit on Page 3, Line 21; Blackstone's $2.6 million credit on Page 4, Line 20; and Newport's $0.9 million credit on Page 5, Line 20.

How to calculate the CTC rates:

How to Calculate the new CTC Rates			
Oct-Dec 2019 Prior Year True- Up	1		End of the Year Account Balance
		+/-	Estimated Revenue VS Actuals
	2	+/-	Estimated Expenses VS Actuals
	3	+/-	Return on the balance
Jan-Sep 2020 Current Year Actuals; Oct-Dec 2020 Equal to Estimate	1	=	New end of the Year Account Balance
		+/-	Estimated Revenue VS Actuals
	2	+/-	Estimated Expenses VS Actuals
	3	+/-	Return on the balance
2021 The Following Year Estimates	1	=	New end of the Year Account Balance
		+/-	Estimated Revenue VS Actuals
	2	+/-	Estimated Expenses VS Actuals
	3	+/-	Return on the balance
	1	=	Collecion of Prior Year Including Interests
	4	Divided	Estimated KWHs
New Rate		=	New CTC Rate

Calculation of the New CTC Rate:

MONTAUP ELECTRIC COMPANY d/b/a NATIONAL GRID
RECONCILIATION OF THE FORMER BLACKSTONE VALLEY ELECTRIC COMPANY CTC CALCULATION
OCTOBER 1, 2018 THROUGH SEPTEMBER 30, 2019

		Revenues		Expenses						
Line		Kwhs (a)	Termination Charge (b)	Decom (c)	HQ (d)	PBR (e)	VT Yankee (f)	BVE Share (g)	Excess ADIT (h)	Total (i)
1	Prior End-of-Year Account Balance from Previous Filing									($2,486,740)
2	Less: Cumulative Pre-Tax Return from Previous Filing, October through December Prior Year									$73,782
3	Plus: Prior Year Adjustments									$0
4	Plus: Estimated Revenue, October through December Prior Year	428,486,500	($0.001460)							($625,706)
5	Less: Actual Revenue, October through December Prior Year	293,401,211	($0.001500)							$440,102
6	Less: Estimated Expense, October through December Prior Year				$481,750			29.13%		($140,334)
7	Plus: Actual Expense, October through December Prior Year			$4,747	($690,147)	$0	$6,704	29.13%	$488,880	$291,176
8	Plus: Cumulative Pre-Tax Return, October through December Prior Year									($77,886.56)
9	Prior End-of-Year Account Balance from Current Filing									($2,525,607)
10	Plus: Estimated Revenue, January through September Current Yea	1,304,322,750	($0.001192)							($1,554,253)
11	Less: Actual Revenue, December billed in January Current Year	63,288,432	($0.001500)							$94,933
12	Less: Actual Revenue, January billed in January Current Year	47,391,288	($0.001200)							$56,870
13	Less: Actual Revenue, February through September Current Year	846,641,363	($0.001200)							$1,015,970
14	Less: Estimated Expense, January through September Current Year				$1,401,750			29.13%		($408,330)
15	Plus: Actual Expense, January through September Current Year			$7,440	($2,900,823)	($40,463)	$3,533	29.13%		($853,600)
16	Plus: Cumulative Pre-Tax Return, Current Year									($248,340.47)
17	Plus: Current Year Collection of Prior Year Balance Including Interest									$2,616,777
18	Current End Of Year Account Balance									($1,805,581)
19	Plus: Estimated Expense, Following Year				$1,584,000			29.13%		$461,419
20	Plus: Cumulative Pre-Tax Return, Following Year									($94,418)
21	Collection of Prior Year Balance Including Interest									($1,438,580)
22	Estimated Kwhs									1,762,428,000
23	New CTC Rate									($0.0008)

Oct-Dec Prior Year True -Up

Jan-Sep Curr Year Actuals; Oct-Dec Equal to Est

The Following Year Estimates

Page 1

NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID
RECONCILIATION FOR THE FORMER NEW ENGLAND POWER COMPANY CTC CALCULATION
OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020

		Revenues		Expenses						
Line		Kwhs (a)	Termination Charge (b)	Decom (c)	HQ (d)	PBR (e)	Environ-ment (f)	VT Yankee (g)	NECO Share (h)	Total (i)
1	Prior End-of-Year Account Balance from Previous Filing									($5,222,284)
2	Less: Cumulative Pre-Tax Return from Previous Filing, October through December Prior Year									$162,738
3	Plus: Estimated Revenue, October through December Prior Year	1,638,456,049	($0.000860)							($1,408,343)
4	Less: Actual Revenue, October through December Prior Year	1,226,630,628	($0.000900)							$1,103,968
5	Less: Estimated Expense, October through December Prior Year				$1,127,500				22.4102%	($252,675)
6	Plus: Actual Expense, October through December Prior Year			($5,819,685)	($3,949,017)	$0	$2,876	$20,241	22.4102%	($2,184,001)
7	Plus: Cumulative Pre-Tax Return, October through December Prior Year									($176,201)
8	Prior End-of-Year Account Balance from Current Filing									($7,976,797)
9	Plus: Estimated Revenue, January through September Current Year	4,984,183,300	($0.000739)							($3,683,042)
10	Less: Actual Revenue, December billed in January Current Year	219,637,924	($0.000900)							$197,674
11	Less: Actual Revenue, January billed in January Current Year	167,662,242	($0.000700)							$117,364
12	Less: Actual Revenue, February through September Current Year	3,738,816,741	($0.000700)							$2,617,172
13	Less: Estimated Expense, January through September Current Year				$792,000				22.4102%	($177,488)
14	Plus: Actual Expense, January through September Current Year			$49,045.86	($9,989,444)	($387,073.60)	$6,214.64	($112,616.61)	22.4102%	($2,338,248)
15	Plus: Cumulative Pre-Tax Return, Current Year									($832,603)
16	Plus: Current Year Collection of Prior Year Balance Including Interest									$5,147,375
17	Current End Of Year Account Balance									($6,928,595)
18	Plus: Estimated Expense, Following Year				$0				22.4102%	$0
19	Plus: Cumulative Pre-Tax Return, Following Year									($362,320)
20	Less: Unbilled Revenue Adjustment	404,861,338	($0.000739)							$299,171
21	Collection of Prior Year Balance Including Interest									($6,991,744)
22	Estimated Kwhs									6,738,615,821
23	New CTC Rate									($0.0010)

Line Notes:

1	January 2019 filing, Schedule 2, Page 2, Column (7), Line (46) * 1,000,000
2	- January 2019 filing, Schedule 2, Page 2, Column (5), Sum of Lines (43) through (45) * 1,000,000
3(a)	Schedule 1, Page 1, Column (2), Sum of Lines (31) through (33) * 1,000,000
3(b)	Schedule 1, Page 1, Column (9), Line (34) / Schedule 1, Page 1, Column (2), Line (34)
3(i)	3(a) * 3(b)
4(a)	Schedule 2, Page 1a, Column (3), Sum of Lines (31) through (33) * 1,000,000
4(b)	Schedule 2, Page 1a, Column (5), Line (34) / 100
4(i)	4(a) * 4(b) * -1
5(d)	(Schedule 1, Page 8, Column Hydro Quebec, Line 2019 - Schedule 1, Page 9 , Column Hydro Quebec, Line 2019) * 25% * 1,000,000
5(i)	Sum of 5(d) through 5(h) * 5(h) * -1
6(c)	SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines October through December 2019 * 1000
6(d)	(SCHEDULE 5, PAGE 8, Column Actual Costs, Lines October through December 2019 - SCHEDULE 5, PAGE 8, Column Actual Revenues, Lines October through December 2019) * 1000
6(e)	SCHEDULE 6, PAGE 1, Column (3), Lines October through December, 2019 * 1000
6(f)	SCHEDULE 6, PAGE 1, Column (4), Lines October through December, 2019 * 1000
6(g)	SCHEDULE 6, PAGE 2, Column (3), Lines October through December 2019 * 1000
6(i)	Sum of 6(c) through 6(h) * 6(h)
7(i)	Schedule 2, Page 2, Column (8), Sum of Lines (31) through (33) * 1,000,000
8(i)	Sum of Lines 1(i) through 7(i); Schedule 2, Page 2, Column (7), Line (34) * 1,000,000
9(a)	Schedule 1, Page 1, Column (2), Sum of Lines (35) through (43) * 1,000,000
9(b)	Schedule 1, Page 1, Column (9), Line (47) / Schedule 1, Page 1, Column (2), Line (47)
9(i)	9(a) * 9(b)
10(a)-11(i)	CTC Invoice for the month of January 2020
12(a)	Schedule 2, Page 1a, Column (3), Sum of Lines (36) through (43) * 1,000,000
12(b)	Schedule 2, Oage 1a, Column (5), Line (47) / 100
12(i)	12(a) * 12(b) * -1
13(d)	(Schedule 1, Page 8, Column Hydro Quebec, Line 2020 - Schedule 1, Page 9 , Column Hydro Quebec, Line 2020) * 75% * 1,000,000
13(i)	13(d) * 13(h) * -1
14(c)	SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines January through September 2020 * 1000
14(d)	(SCHEDULE 5, PAGE 8, Column Actual Costs, Lines January through September 2020 - SCHEDULE 5, PAGE 8, Column Actual Revenues, Lines January through September 2020) * 1000
14(e)	SCHEDULE 6, PAGE 1, Column (3), Lines January through September, 2020 * 1000
14(f)	SCHEDULE 6, PAGE 1, Column (4), Lines January through September, 2020 * 1000
14(g)	SCHEDULE 6, PAGE 2, Column (3), Lines January through September 2020 * 1000
14(i)	Sum of 14(c) through 14(g) * 14(h)
15(i)	Schedule 2, Page 2, Column (5), Line (47) * 1,000,000
16(i)	Schedule 2, Page 2, Column (6), Line (47) * 1,000,000
17(i)	Sum of Lines 8(i) through 16(i); Schedule 2, Page 2, Column (7), Line (47) * 1,000,000
19(i)	Schedule 2, Page 2, Column (5), Line (48) * 1,000,000
20(b)	9(b)
20(i)	20(a) * 20(b) * -1
21(i)	Sum of Lines 17(i) through 20(i); Schedule 1, Page 1, Column (2), Line (48) * 1,000,000
22(i)	Schedule 1, Page 1, Column (2), Line (48) * 1,000,000
23(i)	21(i) / 22(i); Schedule 1, Page 1, Column (10), Line (48) / 100

MONTAUP ELECTRIC COMPANY d/b/a NATIONAL GRID
RECONCILIATION OF THE FORMER BLACKSTONE VALLEY ELECTRIC COMPANY CTC CALCULATION
OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020

		Revenues		Expenses					
Line		Kwhs (a)	Termination Charge (b)	Decom (c)	HQ (d)	PBR (e)	VT Yankee (f)	BVE Share (g)	Total (h)
1	Prior End-of-Year Account Balance from Previous Filing								($1,805,581)
2	Less: Cumulative Pre-Tax Return from Previous Filing, October through December Prior Year								$54,836
3	Plus: Estimated Revenue, October through December Prior Year	434,774,250	($0.001192)						($518,084)
4	Less: Actual Revenue, October through December Prior Year	274,552,575	($0.001200)						$329,463
5	Less: Estimated Expense, October through December Prior Year				$467,250			29.13%	($136,110)
6	Plus: Actual Expense, October through December Prior Year			($1,082,953)	($866,017)	$0	$2,530	29.13%	($566,998)
7	Plus: Cumulative Pre-Tax Return, October through December Prior Year								($64,047)
8	Prior End-of-Year Account Balance from Current Filing								($2,706,522)
9	Plus: Estimated Revenue, January through September Current Year	1,321,821,000	($0.000816)						($1,078,935)
10	Less: Actual Revenue, December billed in January Current Year	63,905,225	($0.001200)						$76,686
11	Less: Actual Revenue, January billed in January Current Year	48,782,529	($0.000800)						$39,026
12	Less: Actual Revenue, February through September Current Year	831,078,734	($0.000800)						$664,863
13	Less: Estimated Expense, January through September Current Year				$1,188,000			29.13%	($346,064)
14	Plus: Actual Expense, January through September Current Year			$10,446	($2,189,841)	($94,358)	($99,681)	29.13%	($691,381)
15	Plus: Cumulative Pre-Tax Return, Current Year								($285,377)
16	Plus: Current Year Collection of Prior Year Balance Including Interest								$1,899,999
17	Current End Of Year Account Balance								($2,427,705)
18	Plus: Estimated Expense, Following Year				$0			29.13%	$0
19	Plus: Cumulative Pre-Tax Return, Following Year								($126,949.87)
20	Collection of Prior Year Balance Including Interest								($2,554,655)
21	Estimated Kwhs								1,787,024,000
22	New CTC Rate								($0.0014)

Line Notes:

1(h)	January 2019 filing, Schedule 2, Page 2, Column (12), Line 2019 * 1,000
2(h)	- January 2019 filing, Schedule 2, Page 2, Column (10), Sum of Lines Oct-2019 through Dec-2019 * 1,000
3(a)	Schedule 1, Page 1, Column (2), Line 2019 * 25% * 1000
3(b)	Schedule 1, Page 1, Column (8), Line 2019 / 100
3(h)	3(a) * 3(b)
4(a)	Schedule 2, Page 1a, Column (3), Sum of Lines Oct-2019 through Dec-2019 * 1000
4(b)	Schedule 2, Page 1a, Column (5), Line Oct-2019 / 100
4(h)	4(a) * 4(b) * -1
5(d)	Schedule 1, Page 8, Column HQ, Line 2019 * 25% * 1000
5(h)	5(d) * 5(g) * -1
6(c)	ATTACHMENT 1, SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines Oct through Dec 2019 * 1000
6(d)	ATTACHMENT 1, SCHEDULE 5, PAGE 4, Columns (3) and (6), Sum of Lines Oct through Dec 2019 * 1000
6(e)	ATTACHMENT 1, SCHEDULE 6, Column (2), Sum of Lines Oct through Dec, 2019 * 1000
6(f)	ATTACHMENT 1, SCHEDULE 6, Column (4), Sum of Lines Oct through Dec, 2019 * 1000
6(h)	Sum of 6(c) through 6(f) * 6(g)
7(h)	Schedule 2, Page 2, Column (10), Sum of Lines Oct-2019 through Dec-2019 * 1000
8(h)	Sum of Lines 1(h) through 7(h); Schedule 2, Page 2, Column (12), Line 2019 * 1000
9(a)	Schedule 1, Page 1, Column (2), Line 2020 * 75% * 1000
9(b)	Schedule 1, Page 1, Column (8), Line 2020 / 100
9(h)	9(a) * 9(b)
10(a)-11(h)	CTC Invoice for the month of January 2020
12(a)	Schedule 2, Page 1a, Column (3), Sum of Lines Feb-2020 through Sep-2020 * 1000
12(b)	Schedule 2, Page 1a, Column (5), Line Feb-2020 / 100
12(h)	12(a) * 12(b) * -1
13(d)	Schedule 1, Page 8, Column HQ, Line 2020 * 75% * 1000
13(h)	13(d) * 13(g) * -1
14(c)	ATTACHMENT 1, SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines Jan through Sep, 2020 * 1000
14(d)	ATTACHMENT 1, SCHEDULE 5, PAGE 4, Columns (3) and (6), Sum of Lines Jan through Sep, 2020 * 1000
14(e)	ATTACHMENT 1, SCHEDULE 6, Column (2), Sum of Lines Jan through Sep, 2020 * 1000
14(f)	ATTACHMENT 1, SCHEDULE 6, Column (4), Sum of Lines Jan through Sep, 2020 * 1000
14(h)	Sum of 14(c) through 14(f) * 14(g)
15(h)	Schedule 2, Page 2, Column (10), Line 2020 * 1000
16(h)	Schedule 2, Page 2, Column (11), Line 2020 * 1000
17(h)	Sum of Lines 8(h) through 16(h); Schedule 2, Page 2, Column (12), Line 2020 * 1000
18(d)	Schedule 1, Page 8, Column HQ, Line 2021 * 1000
18(h)	18(d) * 18(g)
19(h)	Schedule 2, Page 2, Column (10), Line 2021 * 1000
20(h)	Sum of Lines 17(h) through 19(h); Schedule 1, Page 1, Column (7), Line 2020 * 1000
21(h)	Schedule 1, Page 1, Column (2), Line 2021 * 1000
22(h)	20(h) / 21(h); Schedule 1, Page 1, Column (8), Line 2021 / 100

MONTAUP ELECTRIC COMPANY d/b/a NATIONAL GRID
RECONCILIATION FOR THE FORMER NEWPORT ELECTRIC CORPORATION CTC CALCULATION
OCTOBER 1, 2019 THROUGH SEPTEMBER 30, 2020

		Revenues		Expenses					
Line		Kwhs (a)	Termination Charge (b)	Decom (c)	HQ (d)	PBR (e)	VT Yankee (f)	Nwpt Share (g)	Total (h)
1	Prior End-of-Year Account Balance from Previous Filing								($564,740)
2	Less: Cumulative Pre-Tax Return from Previous Filing, October through December Prior Year								$17,408
3	Plus: Estimated Revenue, October through December Prior Year	168,441,750	($0.001004)						($169,134)
4	Less: Actual Revenue, October through December Prior Year	134,390,297	($0.001000)						$134,390
5	Less: Estimated Expense, October through December Prior Year				$467,250			11.85%	($55,369)
6	Plus: Actual Expense, October through December Prior Year			($1,082,953)	($866,017)	$0	$2,530	11.85%	($230,653)
7	Plus: Cumulative Pre-Tax Return, October through December Prior Year								($20,603)
8	Prior End-of-Year Account Balance from Current Filing								($888,701)
9	Plus: Estimated Revenue, January through September Current Year	510,542,250	($0.000597)						($304,926)
10	Less: Actual Revenue, December billed in January Current Year	29,991,120	($0.001000)						$29,991
11	Less: Actual Revenue, January billed in January Current Year	22,893,945	($0.000600)						$13,736
12	Less: Actual Revenue, February through September Current Year	388,713,886	($0.000600)						$233,228
13	Less: Estimated Expense, January through September Current Year				$1,188,000			11.85%	($140,778)
14	Plus: Actual Expense, January through September Current Year			$10,446	($2,189,841)	($94,358)	($99,681)	11.85%	($281,252)
15	Plus: Cumulative Pre-Tax Return, Current Year								($95,960)
16	Plus: Current Year Collection of Prior Year Balance Including Interest								$594,272
17	Current End Of Year Account Balance								($840,390)
18	Plus: Estimated Expense, Following Year				$0			11.85%	$0
19	Plus: Cumulative Pre-Tax Return, Following Year								($43,946)
20	Collection of Prior Year Balance Including Interest								($884,336)
21	Estimated Kwhs								687,311,000
22	New CTC Rate								($0.0013)

Line Notes:

1(h)	January 2019 filing, Schedule 2, Page 2, Column (12), Line 2019 * 1,000
2(h)	- January 2019 filing, Schedule 2, Page 2, Column (10), Sum of Lines Oct-2019 through Dec-2019 * 1,000
3(a)	Schedule 1, Page 1, Column (2), Line 2019 * 25% * 1000
3(b)	Schedule 1, Page 1, Column (8), Line 2019 / 100
3(h)	3(a) * 3(b)
4(a)	Schedule 2, Page 1a, Column (3), Sum of Lines Oct-2019 through Dec-2019 * 1000
4(b)	Schedule 2, Page 1a, Column (5), Line Oct-2019 / 100
4(h)	4(a) * 4(b) * -1
5(d)	Schedule 1, Page 8, Column HQ, Line 2019 * 25% * 1000
5(h)	5(d) * 5(g) * -1
6(c)	ATTACHMENT 1, SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines Oct through Dec 2019 * 1000
6(d)	ATTACHMENT 1, SCHEDULE 5, PAGE 4, Columns (3) and (6), Sum of Lines Oct through Dec 2019 * 1000
6(e)	ATTACHMENT 1, SCHEDULE 6, Column (2), Sum of Lines Oct through Dec, 2019 * 1000
6(f)	ATTACHMENT 1, SCHEDULE 6, Column (4), Sum of Lines Oct through Dec, 2019 * 1000
6(h)	Sum of 6(c) through 6(f) * 6(g)
7(h)	Schedule 2, Page 2, Column (10), Sum of Lines Oct-2019 through Dec-2019 * 1000
8(h)	Sum of Lines 1(h) through 7(h); Schedule 2, Page 2, Column (12), Line 2019 * 1000
9(a)	Schedule 1, Page 1, Column (2), Line 2020 * 75% * 1000
9(b)	Schedule 1, Page 1, Column (8), Line 2020 / 100
9(h)	9(a) * 9(b)
10(a)-11(h)	CTC Invoice for the month of January 2020
12(a)	Schedule 2, Page 1a, Column (3), Sum of Lines Feb-2020 through Sep-2020 * 1000
12(b)	Schedule 2, Page 1a, Column (5), Line Feb-2020 / 100
12(h)	12(a) * 12(b) * -1
13(d)	Schedule 1, Page 8, Column HQ, Line 2020 * 75% * 1000
13(h)	13(d) * 13(g) * -1
14(c)	ATTACHMENT 1, SCHEDULE 4, Columns (3), (6), and (9), Sum of Lines Jan through Sep, 2020 * 1000
14(d)	ATTACHMENT 1, SCHEDULE 5, PAGE 4, Columns (3) and (6), Sum of Lines Jan through Sep, 2020 * 1000
14(e)	ATTACHMENT 1, SCHEDULE 6, Column (2) , Sum of Lines Jan through Sep, 2020 * 1000
14(f)	ATTACHMENT 1, SCHEDULE 6, Column (4) , Sum of Lines Jan through Sep, 2020 * 1000
14(h)	Sum of 14(c) through 14(f) * 14(g)
15(h)	Schedule 2, Page 2, Column (10), Line 2020 * 1000
16(h)	Schedule 2, Page 2, Column (11), Line 2020 * 1000
17(h)	Sum of Lines 8(h) through 16(h); Schedule 2, Page 2, Column (12), Line 2020 * 1000
18(d)	Schedule 1, Page 8, Column HQ, Line 2020 * 1000
18(h)	18(d) * 18(g)
19(h)	Schedule 2, Page 2, Column (10), Line 2021 * 1000
20(h)	Sum of Lines 17(h) through 19(h); Schedule 1, Page 1, Column (7), Line 2021 * 1000
21(h)	Schedule 1, Page 1, Column (2), Line 2021 * 1000
22(h)	20(h) / 21(h); Schedule 1, Page 1, Column (8), Line 2021 / 100

PUC 2-10

Request:

Is the $10.4 million credit on Bates page 97 a component of an overall larger credit due to NEP's wholesale customers to whom the CTC settlement applies? If yes, please identify each entity being credited by NEP, the total value of the credit allocable to the customers and explain the basis by which the credit is allocated across the applicable entities to whom the CTC settlement applies.

Response:

Yes, the $10.4 million credit on Bates page 97 is the Company's share of an overall credit due to NEP's wholesale customers to whom the CTC settlement applies. The total amount of the credit that NEP is allocating to its wholesale customers under the CTC settlement is $40.3 million.

The share of all amounts that NEP passes on to its wholesale customers under the CTC settlement is fixed and was based on each customer's amount of purchased power generation. . Accordingly, NEP is crediting Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid $24.2 million and Granite State Electric Company d/b/a Liberty Utilities $836,000. The former Montaup Electric Company (now a part of NEP) is crediting the former Eastern Edison Company (now a part of Massachusetts Electric Company) $4.8 million. Please refer to the Company's responses and attachments to PUC 2-9 for a detailed explanation of the CTC calculation.

Prepared by or under the supervision of: Kathleen M. Hammer

PUC 2-11

Request:

Assuming the Company's delivery forecast predicts actual deliveries for the FY 22 rate period, what is the Company's estimate of the amount that will be credited to Narragansett Electric's delivery customers in FY 22 pursuant to the proposed transition charge? Please provide the calculation.

Response:

Assuming the Company's delivery forecast predicts actual deliveries for the FY22 rate period, the Company estimates that the total amount credited to Narragansett Electric's delivery customers would be $7,903,843, as shown below:

6,994,551,209 kWh x ($0.00113) per kWh = $7,903,843

Prepared by or under the supervision of: Adam S. Crary

PUC 2-12

Request:

Assuming actual deliveries equal forecast deliveries of 6.9 billion kWh and the Narragansett transition factor was recalculated based on forecast deliveries of 6.9 billion kWh and credited to retail customers at the resulting factor:

a. What total amount would Narragansett credit ratepayers?
b. What total amount would NEP credit to Narragansett?
c. If the answers to (a) and (b) above are not equal, is it correct that NEP will compensate Narragansett at a weighted cost of capital (WACC)? If so, would it be the WACC of NEP or Narragansett?

Response:

Please see Attachment PUC 2-12, which illustrates the requested calculations in sections a. and b.

a. Assuming actual kWh deliveries equal forecast kWh deliveries of 6.9 billion kWh and Narragansett Electric's Non-bypassable Transition Charge was recalculated based on forecast kWh deliveries of 6.9 billion kWh and credited to retail delivery customers, the resulting illustrative Base Non-bypassable Transition Charge would be a credit of \$0.00149 per kWh, as shown in Section 1, Column (e). This charge would credit customers \$10,421,881 as shown in Section 2, Column (k).

b. Section 2 illustrates that NEP would credit Narragansett Electric \$7,863,598 using the assumption that actual kWh deliveries equal forecasted kWh deliveries of 6.9 billion kWh during FY22. This amount is shown on Section 2, Column (i), line (8).

c. NEP will compensate Narragansett Electric at NEP's 10.46 percent WACC, as shown in NEP's 2020 CTC Reconciliation Report submitted in response to PUC 1-30, Attachment PUC-1-30-2, Page 31. Montaup Electric Company ("Montaup") will compensate Blackstone Valley Electric Company and Newport Electric Corporation at Montaup's 10.458 percent WACC, as shown in Montaup's 2020 CTC Reconciliation Report submitted in response to PUC 1-30, Attachment PUC-1-30-3, Pages 32 and 65. The WACCs were established in the Settlements provided in PUC 2-8, Attachments PUC-2-8-1, Page 52; PUC-2-8-4, Page 3; and PUC-2-8-5, Page 3; and adjusted over time for changes to state and federal tax rates.

The Narragansett Electric Company

Section 1: Individual CTC Amounts

		2021 CTC Rate	Forecasted GWhs	Expected CTC Costs	Retail Forecast	Illustrative Transition Charge
		(a)	(b)	(c)	(d)	(e)
(1)	Narragansett	($0.00104)	6,738.616	($6,991,744)		
(2)	BVE	($0.00143)	1,787.024	($2,554,655)		
(3)	Newport	($0.00129)	687.311	($884,336)		
(4)	Total			($10,430,735)	6,994,551,209	($0.00149)

Section 2: Total Estimated CTC Billings and Transition Charge Billings

		2021 CTC Rate	Allocation of Forecast to Service Area	Retail Forecast	Estimated CTC Billings to NECO	Illustrative Transition Charge	Estimated Transition Charge Billings to Customers
		(f) = (a)	(g)	(h)	(i) = (f) x (h)	(j) = (e)	(k) = (g) x (j)
(5)	Narragansett	($0.0010)	75.0%	5,243,956,730	($5,243,957)		
(6)	BVE	($0.0014)	17.0%	1,188,682,938	($1,664,156)		
(7)	Newport	($0.0013)	8.0%	561,911,541	($730,485)		
(8)	Total			6,994,551,209	($7,638,598)	($0.00149)	($10,421,881)

(1)(a) January 2021 NEP CTC Reconciliation Report, Schedule 1, page 1, line (48), Column (10)
(2)(a) January 2021 BVE/NWPT Combined CTC Reconciliation Report, Schedule 1 BVE, page 1, Column (8)
(3)(a) January 2021 BVE/NWPT Combined CTC Reconciliation Report, Schedule 1 NWPT, page 1, Column (8)
Column (a) x Column (b) x 1,000,000
(1)(b) January 2021 NEP CTC Reconciliation Report, Schedule 1, page 1, line (47), Column (2)
(2)(b) January 2021 BVE/NWPT Combined CTC Reconciliation Report, Schedule 1 BVE, page 1, Column (2)
(3)(b) January 2021 BVE/NWPT Combined,CTC Reconciliation Report, Schedule 1, NWPT page 1, Column (2)
Column (a) x Column (b) x 1,000,000
(1)(c) January 2021 NEP CTC Reconciliation Report, Schedule 1, page 1, line (47), Column (9)
(2)(c) January 2021 BVE/NWPT Combined CTC Reconciliation Report, Schedule 1 BVE, page 1, Column (7)
(3)(c) January 2021 BVE/NWPT Combined CTC Reconciliation Report, Schedule 1, NWPT page 1, Column (7)
Column (a) x Column (b) x 1,000,000
(4)(d) Company forecast per Schedule ELF-1
(4)(e) Line (4)(c) ÷ Line (4)(d), truncated to 5 decimal places
(f) Actual billed CTC rates are rounded to the 4th decimal
(g) Allocation based on actual 2020 kWh deliveries billed to customers as reflected in CTC bills to the Company during 2020