nationalgrid

Thomas G. Robinson
Deputy General Counsel
National Grid

November 15, 2005

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: <u>January 2006 Retail Rate Filing and Request for Approval of Dispensation of Settlement Proceeds</u>

Dear Ms. Massaro:

Enclosed on behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company") are ten copies of two separate filings. The first is the Company's Request for Approval of Dispensation of Settlement Proceeds. The second is the Company's January 2006 Retail Rate Filing that we file each year at this time, related to our annual reconciliations. Each is briefly summarized below.

In the first filing, National Grid is making a proposal regarding the dispensation of $16.5 million in proceeds to be received by the Company for the benefit of its customers. This filing is supported by the testimony and exhibits of Ronald T. Gerwatowski and Jeanne A. Lloyd. In summary, the Company is proposing to use $8 million of the settlement proceeds to implement an "Enhanced Low Income Discount Program" for customers receiving service on the Company's Residential Low-Income Rate A-60 for a period of four years. The discount would be applied against the first 450 kWh of monthly use and would be reflected on customer bills as a lower distribution energy charge. National Grid is proposing this discount, which is essentially the same as that proposed by the Division of Public Utilities and Carriers in Docket No. 3689, to help mitigate the rising cost of electricity to customers on Rate A-60. Also included in this filing is a proposal for the return of the balance of $8.5 million to customers through a reduction in the non-bypassable transition charge during 2006.

The second filing is the Company's January 2006 Retail Rate Filing which presents the reconciliation of its tariff adjustment provisions through September 2005, the estimate of its 2006 transmission expenses pursuant to its Transmission Service Cost Adjustment Provision, and the calculation of its weighted average non-bypassable transition charge pursuant to its Non-Bypassable Transition Charge Adjustment Provision. National Grid's filing proposes rate changes resulting from these reconciliations, estimates and calculations effective for use on and after January 1, 2006. The Company's filing contains the direct testimony and exhibits of Jeanne A. Lloyd, Michael D. Laflamme and Susan L. Hodgson in support of the proposed rate changes.

As set forth in the testimony and exhibits contained in the second filing, the Company is reconciling its actual revenue and expenses for the 12 months ending September 30, 2005 under its Non-Bypassable Transition Charge Adjustment Provision and its Transmission Service Cost Adjustment Provision. The Company has also estimated its 2006 annual expenses under its Transmission Service Cost Adjustment Provision. The forecast of 2006 transmission costs is described in the testimony of Ms. Hodgson. In addition, the Company is also reflecting the impact of a settlement reached with various Rhode Island parties for the flow-through of proceeds received by New England Power Company associated with the bankruptcy of USGen New England, Inc. This settlement and its treatment is described by Mr. Laflamme in his testimony. As a result, the Company is proposing to decrease its Transition Charge for 2006 from the present level of 0.845¢ per kWh to 0.575¢ per kWh. The Company is also proposing to increase its Transmission Service Adjustment Factor for 2006 from 0.239¢ per kWh to 0.371¢ per kWh.

The rate changes presented by the Company's January 2006 Retail Rate Filing and the proposed reduction to the non-bypassable transition charge contained in the Dispensation of Settlement Proceeds Filing would decrease the total bill of a 500 kWh residential customer by $0.72, or 1.0%, from $70.58 to $69.86. When taken with the scheduled termination of the Customer Credit, extended through December 31, 2005 by the Commission, the same 500 kWh residential customer would see a monthly increase of $0.99, or 1.4%, from $70.58 to $71.57.

Thank you for your attention to this matter. If you have any questions, please feel free to contact me at (508) 389-2877.

Very truly yours,

Thomas G. Robinson

Thomas G. Robinson

Enclosures

cc: Docket 3706 Service List

Certificate of Service

I hereby certify that a copy of the cover letter and accompanying material(s) have been hand-delivered or sent via U.S. mail to the parties listed below.

Joanne M. Scanlon
National Grid

November 15, 2005
Date

Narragansett Electric Co. – Standard Offer Rate Filing – Docket No. 3706
Service list as 11/03/05

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National Grid

January 2006 Retail Rate Filing

Testimony and Exhibits
Of
Jeanne A. Lloyd,
Michael D. LaFlamme, and
Susan L. Hodgson

November 15, 2005

Submitted to:
Rhode Island Public Utilities Commission
R.I.P.U.C. Docket No. _____

Submitted by:

DIRECT TESTIMONY

OF

JEANNE A. LLOYD

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I. <u>Introduction and Qualifications</u>

Q. Please state your full name and business address.

A. My name is Jeanne A. Lloyd, and my business address is 55 Bearfoot Road, Northborough, Massachusetts 01532.

Q. Please state your position.

A. I am a Principal Financial Analyst in the Distribution Regulatory Services Department of National Grid USA Service Company, Inc. The Distribution Regulatory Services Department provides rate related support to The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Company").

Q. Please describe your educational background and training.

A. In 1980, I graduated from Bradley University in Peoria, Illinois with a Bachelor's Degree in English. In December 1982, I received a Master of Arts Degree in Economics from Northern Illinois University in De Kalb, Illinois.

Q. Please describe your professional experience?

A. I was employed by EUA Service Corporation in December 1990 as an Analyst in the Rate Department. I was promoted to Senior Rate Analyst on January 1, 1993. My responsibilities included the study, analysis and design of the retail electric service rates, rate riders and special contracts for the EUA retail companies. I assumed my present position after the merger of New England Electric System and Eastern Utilities Associates in April 2000. Prior to my employment at EUA, I was on the staff of the

Missouri Public Service Commission in Jefferson City, Missouri in the position of research economist. My responsibilities included presenting both written and oral testimony before the Missouri Commission in the areas of cost of service and rate design for electric and natural gas rate proceedings.

Q. Have you previously testified before Rhode Island Public Utilities Commission ("Commission")?

A. Yes.

II. Purpose of Testimony

Q. What is the purpose of the Company's filing?

A. The Company is requesting Commission approval of the Company's proposed base non-bypassable transition charge ("transition charge"), transition charge adjustment factor, and transmission service adjustment factor effective for usage on and after January 1, 2006. The Company is also presenting the results of the annual reconciliations: Last Resort Service, non-bypassable transition charge, and transmission service. The Company's annual Standard Offer Service reconciliation and Standard Offer Service rate proposal are pending before the Commission in Docket No. 3706.

Q. Please describe the changes being proposed to each component of the Company's charges.

A. The Company is proposing to decrease its transition charge from its current level of 0.845¢ per kWh to 0.575¢ per kWh for calendar year 2006. The proposed charge is based upon three components. The first component is New England Power Company's ("NEP") annual Contract Termination Charge ("CTC") for 2006 for Narragansett Electric Company, the former Blackstone Valley Electric Company ("BVE") and the former Newport Electric Corporation ("Newport"). The 2006 CTC charges are explained more fully in the testimony of Mr. Michael D. LaFlamme. At the time of this filing, NEP has not finalized its 2006 CTCs, but expects to do so by way of a reconciliation report that will be issued to the Commission and other parties to the wholesale restructuring settlements by December 1, 2005. The Company intends to update its proposed transition charge prior to the hearing in this proceeding if the final CTCs result in a transition charge that is different from those included in this filing.

The second component is the Company's request to reflect in the calculation of the transition charge $8.5 million of $20 million the Company will receive from NEP. The $20 million to be paid by NEP is pursuant to two settlements among the Company, NEP, the Commission, the Rhode Island Division of Public Utilities and Carriers (the "Division") and the Rhode Island Attorney General ("RIAG"), (the "FERC Settlements"). One of the settlements is more fully described in the testimony of Mr. Laflamme and the second agreement is included as an attachment to a separate settlement by and among the Company, the Division, the Commission, and the RIAG (the "State Settlement"), which is being submitted by the Company concurrent with this filing. The Company's proposal to include $8.5 million in the 2006 transition charge contributes to a reduction to the transition charge of 0.105¢ per kWh.

The third component is the proposed transition charge adjustment factor resulting from the annual reconciliation of the transition charge, which is a charge of 0.001¢ per kWh.

The Company is proposing a transmission service adjustment factor of 0.371¢ per kWh, an increase of 0.132¢ per kWh from the current factor of 0.239¢ per kWh. The increase in the factor is due primarily to an increase in the forecast of transmission expenses for 2006 and an under collection of transmission expenses incurred for the period October 2004 through September 2005.

Exhibit JAL-1 presents a summary of the proposed rate changes. The effect of these proposed rate changes is a net decrease of 0.138¢ per kWh.

III. Transition Charge

Base Transition Charge

Q. Please describe the Company's transition charge.

A. The transition charge is intended to recover from all retail delivery service customers the CTC billed to the Company by NEP, including charges in effect under the former Montaup Electric Company ("Montaup") CTC. The transition charge was originally designed to change annually as NEP and Montaup established their CTCs for the upcoming calendar year. In addition, the Company reconciles the revenue it bills under its transition charge against the CTC billed to it by NEP and can propose to implement a transition charge adjustment factor to refund an over recovery of CTC costs or collect an under recovery of CTC costs.

Q. What is the Company's proposal in this proceeding?

A. The Company is proposing a transition charge during 2006 of 0.575¢ per kWh. The charge represents (i) the weighted average base transition charge of 0.679¢ per kWh, (ii) a transition charge adjustment factor of 0.001¢ per kWh designed to collect the transition charge under recovery for the period October 2004 through September 2005, and (iii) a credit of 0.105¢ per kWh due to the application of the $8.5 million credit referred to earlier in my testimony.

Q. How is the weighted average base transition charge calculated?

A. Exhibit JAL-2, page 1, shows the calculation of the weighted average base transition charge for 2006. The preliminary individual CTCs and estimated GWhs for Narragansett, BVE and Newport, shown in Section I of page 1, are based upon the most recent estimate of NEP's 2006 CTCs. The individual company CTCs determined in Section I are aggregated in Section II and divided by the total GWh deliveries to arrive at a weighted average base transition charge of 0.679¢ per kWh.

<u>Transition Charge Reconciliation</u>

Q. Please describe how the Company reconciles its transition charge.

A. The Company reconciles transition charge revenue and CTC expense in accordance with its Non-Bypassable Transition Charge Adjustment Provision, which provides for an annual reconciliation of the Company's total CTC expense against the Company's total revenue from its transition charge. The excess or deficiency is to be refunded to or collected from customers with interest accruing at the rate in effect for customer deposits.

The reconciliation is prepared on a monthly basis and for this filing covers the reconciliation period October 2004 through September 2005, as reflected in Exhibit JAL-3. Page 1 shows a summary of the reconciliation for the combined company. Pages 2 through 4 show individual reconciliations for Narragansett, BVE, and Newport.

Q. What is the total Company transition charge reconciliation balance for the year ending September 30, 2005?

A. The balance for the period October 2004 through September 2005, shown in Exhibit JAL-3, page 1, reflects an under recovery of $142,922.

Q. How is the Company proposing to treat the under recovery for the period October 2004 through September 2005?

A. As discussed earlier, the Company is proposing to increase the weighted average transition charge of 0.679¢ per kWh, calculated on Exhibit JAL-2, page 1, by a transition charge adjustment factor of 0.001¢ per kWh, as calculated in Exhibit JAL-2, page 2. The transition charge under recovery, including interest during the recovery period, of $146,036 on Line (2) on page 2 of Exhibit JAL-2, is divided by the 2006 forecasted kWh deliveries, resulting in a charge of 0.001¢ per kWh. This charge, when added to the weighted average transition charge of 0.679¢ per kWh, produces a net transition charge of 0.680¢ per kWh, as shown on Line (5).

Q. What does page 5 of Exhibit JAL-3 reflect?

A. Page 5 of Exhibit JAL-3 presents the status of the approximately $437,000 refund of a transition charge over recovery from the period October 2003 through September 2004. The Company is refunding this over recovery during 2005 through the 2005 transition charge. Page 5 of Exhibit JAL-3 shows that as of October 31, 2005, the balance remaining to be refunded is approximately $134,000. The Company will continue to refund customers through December 2005 and any residual balance, positive or negative, will be credited or charged to the base transition reconciliation in the month of January 2006.

Transition Charge Credit

Q. Please describe the Company's proposal to provide a credit to the transition charge.

A. As explained in a separate filing to the Commission, the Company is proposing to apply a credit to the transition charge of $8.5 million of the $20 million the Company will receive from NEP pursuant to the FERC Settlements. This would reduce the 2006 base transition charge from 0.680¢ per kWh to 0.575¢ per kWh. This calculation is shown on Exhibit JAL-2, Section 2.

IV. Transmission Charge

Q. What is the Company's proposed Transmission Adjustment Factor?

A. The Company's proposed Transmission Adjustment Factor is 0. 371¢ per kWh as shown on Exhibit JAL-4, Line (8). This factor, if implemented, will result in a total Company average transmission charge of 0.765¢ per kWh, as shown on Line (6) of Exhibit JAL-4, consisting of the following individual components:

1) A factor of 0.653¢ per kWh, representing the Company's 2006 forecasted transmission expenses,

2) A factor of 0.088¢ per kWh designed to collect an under recovery of approximately $7.0 million incurred for the period October 2004 through September 2005, and

3) A factor of 0.024¢ per kWh, designed to collect the Company's share of uplift expenses incurred from January 1999 through May 2004.

Each of these adjustments is discussed in more detail below. Subtracting from the total Company average transmission charge of 0.765¢ per kWh the base transmission charge of 0.394¢ per kWh, as calculated on page 2 of Exhibit JAL-4, results in a proposed transmission adjustment factor of 0.371¢ per kWh

<u>Transmission Cost Forecast</u>

Q. Has the Company prepared a forecast of transmission costs for 2006?

A. Yes, it has. It is included in the testimony and exhibits of Ms. Susan L. Hodgson, who will explain the forecast and how it was derived.

Q. What is the result of the forecast?

A. The average transmission cost per kWh of 0.653¢ per kWh as shown on Line (3) of Exhibit JAL-4 is calculated by dividing forecasted transmission cost for 2006 of approximately $52.8 million by the Company's forecast of kWh deliveries during 2006.

<u>Transmission Service Reconciliation</u>

Q. Please discuss the Company's current transmission service reconciliation.

A. The Company's transmission service reconciliation is shown in Exhibit JAL-5. This reconciliation reflects actual transmission revenue for the period October 2004 through September 2005, actual transmission expenses for the period October 2004 through July 2005 and estimated expenses for August and September 2005. This reconciliation is provided in accordance with the Company's Transmission Service Cost Adjustment Provision, which allows for the reconciliation, along with interest on any balance, and the recovery or refund of any under collection or over collection, respectively.

Q. What is the balance of the transmission reconciliation as of September 2005?

A. Exhibit JAL-5, page 1, shows that the balance of the transmission reconciliation as of September 2005 is an under recovery of approximately $7.0 million.

Q. Please describe the calculation of the recovery factor designed to collect the under recovery incurred for the period October 2004 through September 2005.

A. The under recovery of $7.0 million plus interest accrued through December 2006 of approximately $152,000, translates to a recovery factor of 0.088¢ per kWh, which is calculated by dividing the amount to be collected, including an estimate of interest incurred during the recovery period, by estimated kWh deliveries for the period January 2006 through December 2006. This calculation is shown on page 14 of Exhibit JAL-5.

Q. How does the Company plan to reconcile estimated expenses for August and September 2005 to actual expenses?

A. Actual expenses for August and September 2005 will be compared to the estimated expenses included in this period's reconciliation. The difference, positive or negative, will be included as an adjustment in October 2005 to the transmission reconciliation for the period October 2005 through September 2006 to be filed with the Commission at this time next year.

Q. What is the status of the 2005 transmission under recovery as shown on Exhibit JAL-5, page 8?

A. The 2005 transmission under recovery factor of 0.048¢ per kWh was implemented on January 1, 2005 and designed to collect an under recovery of approximately $3.8 million incurred during the period October 2003 through September 2004. The 2005 factor was approved in Docket No. 3648 and was intended to be a 12-month factor. Page 8 of Exhibit JAL-5 shows that as of October 31, 2005, the balance remaining to be recovered is approximately $766,000. The Company will continue to charge customers through December 2005 and any residual balance, positive or negative, will be credited or charged to the base transmission reconciliation in the month of January 2006.

Q. What does page 5 of Exhibit JAL-5 reflect?

A. Page 5 of Exhibit JAL-5 presents the final balance of the approximately $4.8 million refund of a transmission over recovery from the period October 2002 through September 2003. This over recovery was credited to customers during 2004 through the 2004 transmission adjustment factor. Page 5 shows that of the $4.8 million to be passed back to customers, all but $4,600 was credited to customers. The Company has reflected this final amount as a credit to customers on page 1 of Exhibit JAL-5 in column (c) in the month of January 2005.

Q. What does page 11 of Exhibit JAL-5 reflect?

A. Page 11 of Exhibit JAL-5 shows the status of the recovery of the Company's share of uplift costs that had been incurred for the period January 1999 through May 2004. This recovery mechanism was approved by the Commission in Docket No. 3617. The approximately $5.6 million allowed to be recovered is to be recovered over three years, from January 2005 through December 2007.

V. <u>Last Resort Service Reconciliation</u>

Q. Has the Company prepared a Last Resort Service reconciliation for the year ending September 2005?

A. Yes. The Company's Last Resort Service reconciliation for the period October 2004 through September 2005 is shown in Exhibit JAL-6. This exhibit shows that the balance is an over recovery of $631,413.

Q. Please describe the Last Resort Service reconciliation in more detail.

A. The Last Resort Service reconciliation compares the total cost of purchased power for Last Resort Service to revenue billed to Last Resort Service customers. Any excess or deficiency is to be refunded to or collected from customers, with interest, under a methodology approved by the Commission at the time of the Company's annual reconciliation filing.

Included in this year's reconciliation are separate reconciliations for residential Last Resort Service, shown on Exhibit JAL-6, page 2 and for commercial and industrial ("C&I") Last Resort Service, shown on page 3.

Q. Why has the Company prepared separate reconciliations for residential and C&I Last Resort Service?

A. The Company is now tracking the recovery of Last Resort Service expenses separately for the residential and C&I classes because the retail rates charged to each class and the monthly wholesale prices incurred by each class are different. Beginning in September 2003, the Company began procuring Last Resort Service for residential and C&I customers under separate contracts. Each contract specifies monthly prices for Last Resort Service, but the prices for residential service are different from those contained in the C&I contract. Pursuant to the Last Resort Service tariff, R.I.P.U.C. No. 1165, residential customers are charged the Standard Offer Service rate for Last Resort Service while C&I customers are charged the monthly prices specified in the C&I Last Resort Service contract, adjusted for losses.

Q. What are the results of the reconciliations?

A. The residential reconciliation on page 2 of Exhibit JAL-6 shows an over recovery of $45,059 for the period October 2004 through September 2005. The C&I reconciliation on page 3 of Exhibit JAL-6 shows for the same period an over recovery of $586,355. The total over recovery for Last Resort Service is $631,413.

Q. How is the Company proposing to treat the Last Resort Service over recovery?

A. The Company proposes to use the Last Resort Service over recovery to offset fuel index payments in the Standard Offer Service reconciliation. The Company made a similar request in Docket No. 3479 which was approved by the Commission.

VI. Revised Tariff Cover Sheets

Q. Has the Company prepared revised tariff cover sheets?

A. Yes. The revised tariff cover sheets reflecting rate changes effective January 1, 2006 are included in Exhibit JAL-7. Exhibit JAL-7 also includes a marked to show changes version of the revised tariff cover sheets. In addition to the changes to the transition charge and the transmission adjustment factor, the cover sheets also reflect the elimination of the Customer Credit effective January 1, 2006. It should also be noted that for some rate classes, approved scheduled changes in distribution charges also occur effective January 1, 2006. These rate changes were approved by the Commission in Docket No. 3617, and are the result of the “phased-in” consolidation of several of the Company’s existing rate classes.

VII. Typical Bills

Q. Has the Company provided a typical bill analysis to illustrate the impact of the proposed rate changes?

A. Yes it has. The first typical bill is a simplified analysis which attempts to isolate the impacts of the proposed rates in this filing for a 500 kWh customer taking service on Residential Rate A-16. Exhibit JAL-8, Line 1 shows the impact of the Company's proposed transition charge of 0.575¢ per kWh and proposed transmission adjustment factor of 0.371¢ per kWh is a decrease of $0.72, or (1.0%) as compared to the rates currently in effect. It does not reflect the scheduled rate changes I mention above. Line 2 of Exhibit JAL-8 shows the impact of the proposed transition charge excluding the proposed transition charge credit, yielding a transition charge of 0.680¢ per kWh, and the proposed transmission adjustment factor of 0.371¢ per kWh is a decrease of $0.17, or 0.2%. Lines 3 and 4 show the monthly bill impacts using the same rate assumptions as in Lines 1 and 2, respectively, but this time including the scheduled change in the distribution charge and the elimination of the Customer Credit effective December 31, 2005. Lines 3 and 4 show an overall increase of $0.99 or 1.4% and $1.53 or 2.2%, respectively.

Q. Has the Company prepared a typical bill analysis for all rate classes and all rate changes for January 1, 2006?

A. Yes. Exhibit JAL-9 contains the monthly bill impact analysis for each rate class and reflects all scheduled and proposed rate changes for rates effective January 1, 2006.

Q. Do the bill impact analyses presented in Exhibits JAL-8 and JAL-9 reflect the proposed increase in the Standard Offer Service rate proposed for December 1, 2005?

A. No. The typical bill analyses shown in Exhibits JAL-8 and JAL-9 do not reflect any changes to the Standard Offer Service rate, as there is currently a proposal before the Commission in Docket No. 3706 that could result in a Standard Offer Service rate change on January 1, 2006. The Company will update its analysis for its proposed Standard Offer Service rate for January 1, 2006 based upon more current fuel markets and will file this update with the Commission by November 30, 2005 in that docket. Therefore, the Company is presenting only the bill impacts of the rate changes proposed for January 1, 2006 as part of this filing as well as the known, scheduled rate changes discussed above.

VIII. Conclusion

Q. Does this conclude your testimony?

A. Yes it does.

Exhibits

Exhibit JAL-1

Summary of Proposed Rate Changes

Summary of Proposed Rate Changes
Effective for All Rate Classes

		Current Rate (a)	Proposed Change in Rate (b)	Proposed Transition Credit (c)	Proposed Rate (d)
(1)	Transition Charge	$0.00845	($0.00165)	($0.00105)	$0.00575
(2)	Transmission Adjustment Factor	$0.00239	$0.00132	n/a	$0.00371
	Net Rate Change				($0.00138)

Column (a):
(1) per current tariff
(2) per current tariff

Column (b):
(1) Line (1), Column (d) - Line (1), Column (a) - Line (1), Column (c)
(2) Line (2), Column (d) - Line (2), Column (a)

Column (c):
(1) proposed transition credit

Column (d):
(1) Exhibit JAL-2, page 2
(2) Exhibit JAL-4, page 1

Exhibit JAL-2

Calculation of Proposed Non-Bypassable Transition Charge for January 2006

Calculation of Proposed Non-bypassable Transition Charge for January 2006

Section 1: Individual CTC Amounts

	CTC (1)	GWhs (2)	Expected CTC Costs (3)
Narragansett			
2006	\$0.00610	5,496	\$33,525,600
BVE			
2006	\$0.00920	1,452.574	\$13,363,681
Newport			
2006	\$0.00740	589.480	\$4,362,152
Total CTC Costs			\$51,251,433

Section 2: Total Estimated CTC Costs and Transition Charge Calculation

Total	Total Company GWhs (4)	Total Company CTC Costs (5)
2006	7,538.054	\$51,251,433
(6) 2006 Transition Charge		0.679

(1) Per preliminary November 2005 NEP and Montaup CTC Reconciliation Reports, Schedule 1 for 2006
(2) Per preliminary November 2005 NEP and Montaup CTC Reconciliation Reports, Schedule 1 for 2006
(3) (1) x (2)
(4) Sum of Narragansett, BVE and Newport GWhs for appropriate year
(5) Sum of Narragansett, BVE and Newport CTC Costs for appropriate year
(6) (5) ÷ (4)

Calculation of Proposed Non-bypassable Transition Charge for January 2006

Section 1. Calculation of 2006 Non-Bypassable Transition Charge

(1)	2006 Transition Charge		$0.00679
(2)	Transition Charge Under Recovery at September 30, 2005	$146,036	
(3)	divided by: forecasted kWh deliveries for 2006	8,079,436,209	
(4)	Transition charge kWh Recovery Factor		$0.00001
(5)	Proposed Transition Charge for January 1, 2006		$0.00680

Section 2. Calculation of 2006 Non-Bypassable Transition Charge Including Proposed Reconciliation Credit

(6)	Proposed Transition Charge for January 1, 2006		$0.00680
(7)	Proposed Transition Charge Credit	($8,500,000)	
(8)	divided by: forecasted kWh deliveries for 2006	8,079,436,209	
(9)	Transition charge kWh credit		($0.00105)
(10)	Proposed Transition Charge for January 1, 2006 Including Reconciliation Credit		$0.00575

(1) Page 1 of 2, (6)
(2) Exhibit JAL-3, page 1 of 4; 2005 under recovery of $142,922 plus interest during refund period of $3,114.
(3) from Company forecast
(4) Line (2) ÷ Line (3), truncated after 5 decimal places
(5) Line (1) - Line (4)
(6) Line (5)
(7) Proposed Transition Reconciliation Credit
(8) from Company forecast
(9) Line (7) ÷ Line (8), truncated after 5 decimal places
(10) Line (6) - Line (9)

Exhibit JAL-3

Non-Bypassble Transition Charge Reconciliation

Non-Bypassable Transition Charge Reconciliation - Total Company

Company	(Under)/Over Beginning Balance (a)	Transition Charge Revenue (b)	Contract Termination Expense (c)	(Under)/Over (d)	(Under)/Over Ending Balance (e)	Interest (f)	(Under)/Over Ending Balance (g)
Narragansett	$0	$50,248,543	$38,984,839	$11,263,704	$11,263,704	$240,761	$11,504,465
Blackstone Valley Electric	$0	$11,300,806	$20,021,448	($8,720,641)	($8,720,641)	($232,642)	($8,953,284)
Newport	$0	$5,148,575	$7,767,907	($2,619,332)	($2,619,332)	($74,772)	($2,694,103)
Total Company	$0	$66,697,925	$66,774,194	($76,269)	($76,269)	($66,653)	($142,922)

Column (a)	From Pages 2, 3 and 4, column (a): October 2004
Column (b)	From Pages 2, 3 and 4, column (b): Total
Column (c)	From Pages 2, 3 and 4, column (c): Total
Column (d)	column (b) - column (c)
Column (e)	column (a) + column (d)
Column (f)	From Pages 2, 3 and 4, column (h): Total
Column (g)	column (e) + column (f)

Non-Bypassable Transition Charge Reconciliation - Narragansett Electric Company

Month	(Under)/Over Beginning Balance (a)	Transition Charge Revenue (b)	Contract Termination Expense (c)	Monthly (Under)/Over (d)	(Under)/Over Ending Balance (e)	Interest Balance (f)	Monthly Interest Rate (g)	Monthly Interest (h)	Adjustments (i)	Ending Balance (j)
Oct-04	$0	$3,999,097	$2,968,390	$1,030,707	$1,030,707	$515,353	4.010%	$1,691		$1,032,398
Nov-04	$1,032,398	$3,822,189	$2,810,897	$1,011,293	$2,043,691	$1,538,044	4.010%	$5,048		$2,048,738
Dec-04	$2,048,738	$4,309,351	$3,170,172	$1,139,178	$3,187,917	$2,618,327	4.010%	$8,593		$3,196,509
Jan-05	$3,196,509	$4,283,415	$3,259,630	$1,023,784	$4,220,294	$3,708,402	4.010%	$12,170		$4,232,464
Feb-05	$4,232,464	$4,077,861	$3,227,671	$850,190	$5,082,654	$4,657,559	4.010%	$15,285		$5,097,939
Mar-05	$5,097,939	$4,153,415	$3,288,058	$865,357	$5,963,296	$5,530,617	4.270%	$19,305		$5,982,601
Apr-05	$5,982,601	$3,752,281	$2,970,238	$782,043	$6,764,644	$6,373,622	4.270%	$22,247		$6,786,891
May-05	$6,786,891	$3,532,392	$2,799,392	$733,000	$7,519,891	$7,153,391	4.270%	$24,969		$7,544,860
Jun-05	$7,544,860	$3,885,083	$3,062,674	$822,409	$8,367,269	$7,956,064	4.270%	$27,771		$8,395,040
Jul-05	$8,395,040	$4,583,398	$3,627,485	$955,913	$9,350,953	$8,872,996	4.270%	$30,972		$9,381,924
Aug-05	$9,381,924	$4,961,672	$3,928,930	$1,032,741	$10,414,665	$9,898,295	4.270%	$34,550	($25,425)	$10,423,791
Sep-05	$10,423,791	$4,888,390	$3,871,301	$1,017,089	$11,440,880	$10,932,335	4.270%	$38,160		$11,479,040
Total	$0	$50,248,543	$38,984,839	$11,263,704	$11,263,704			$240,761	($25,425)	$11,479,040

Column (a) Column (j) from previous row; beginning balance from Docket No. 3648, filed November 10, 2004

Column (b) From Transition Revenues to Narragansett Electric Company
Column (c) From CTC Bills to Narragansett Electric Company
Column (d) Column (b) - Column (c)
Column (e) Column (a) + Column (d)
Column (f) (Column (a) + Column (e))÷ 2
Column (g) Customer Deposit Rate
Column (h) Column (f) * (1 + Column (g)^(1/12))
Column (i) Aug 2005: Adjustment due to billing error resulting in a reduction to transition charge revenue
Column (j) Column (e) + Column (h) + Column (i)

Non-Bypassable Transition Charge Reconciliation - former Blackstone Valley Electric

	Month	(Under)/Over Beginning Balance (a)	Transition Charge Revenue (b)	Contract Termination Expense (c)	Monthly (Under)/Over (d)	(Under)/Over Ending Balance (e)	Interest Balance (f)	Monthly Interest Rate (g)	Monthly Interest (h)	Adjustments (i)	Ending Balance (j)
*	Oct-04	$0	$365,700	$1,705,070	($1,339,370)	($1,339,370)	($669,685)	4.010%	($2,198)		($1,341,568)
	Nov-04	($1,341,568)	$924,547	$1,654,719	($730,171)	($2,071,739)	($1,706,653)	4.010%	($5,601)		($2,077,340)
	Dec-04	($2,077,340)	$1,007,702	$1,803,670	($795,969)	($2,873,308)	($2,475,324)	4.010%	($8,123)		($2,881,432)
	Jan-05	($2,881,432)	$977,501	$1,692,148	($714,647)	($3,596,079)	($3,238,755)	4.010%	($10,629)		($3,606,708)
	Feb-05	($3,606,708)	$942,617	$1,561,677	($619,061)	($4,225,768)	($3,916,238)	4.010%	($12,852)		($4,238,621)
	Mar-05	($4,238,621)	$966,954	$1,601,512	($634,557)	($4,873,178)	($4,555,899)	4.270%	($15,903)		($4,889,080)
	Apr-05	($4,889,080)	$910,176	$1,507,457	($597,281)	($5,486,361)	($5,187,721)	4.270%	($18,108)		($5,504,469)
	May-05	($5,504,469)	$839,858	$1,391,476	($551,618)	($6,056,087)	($5,780,278)	4.270%	($20,176)		($6,076,263)
	Jun-05	($6,076,263)	$940,437	$1,558,111	($617,674)	($6,693,937)	($6,385,100)	4.270%	($22,287)		($6,716,224)
	Jul-05	($6,716,224)	$1,038,271	$1,720,225	($681,955)	($7,398,179)	($7,057,201)	4.270%	($24,633)		($7,422,812)
	Aug-05	($7,422,812)	$636,843	$1,918,355	($1,281,512)	($8,704,324)	($8,063,568)	4.270%	($28,146)		($8,732,470)
	Sep-05	($8,732,470)	$1,151,092	$1,907,028	($755,936)	($9,488,406)	($9,110,438)	4.270%	($31,800)		($9,520,206)
**	Oct-05	($9,520,206)	$599,107		$599,107	($8,921,099)	($9,220,652)	4.270%	($32,185)		($8,953,284)
	Total	$0	$11,300,806	$20,021,448	($8,720,641)				($232,642)		

* Indicates prorated revenues for usage on and after October 1, 2004
** Indicates estimated revenues for September 2005 billed in October 2005.

Column (a) Column (j) from previous row; beginning balance from Docket No. 3648, filed November 10, 2004
Column (b) From Transition Revenues to Narragansett Electric Company for the former Blackstone Valley Electric
Column (c) From CTC Bills to Narragansett Electric Company for the former Blackstone Valley Electric
Column (d) Column (b) - Column (c)
Column (e) Column (a) + Column (d)
Column (f) (Column (a) + Column (e)) ÷ 2
Column (g) Customer Deposit Rate
Column (h) Column (f) * (1 + Column (g)^(1/12))
Column (i)
Column (j) Column (e) + Column (h) + Column (i)

Non-Bypassable Transition Charge Reconciliation - former Newport Electric Corporation

	Month	(Under)/Over Beginning Balance (a)	Transition Charge Revenue (b)	Contract Termination Expense (c)	Monthly (Under)/Over (d)	(Under)/Over Ending Balance (e)	Interest Balance (f)	Monthly Interest Rate (g)	Monthly Interest (h)	Adjustments (i)	Ending Balance (j)
*	Oct-04	$0	$170,796	$687,936	($517,140)	($517,140)	($258,570)	4.010%	($849)		($517,989)
	Nov-04	($517,989)	$408,139	$630,197	($222,058)	($740,046)	($629,017)	4.010%	($2,064)		($742,111)
	Dec-04	($742,111)	$463,693	$715,856	($252,163)	($994,274)	($868,192)	4.010%	($2,849)		($997,123)
	Jan-05	($997,123)	$473,446	$701,548	($228,102)	($1,225,225)	($1,111,174)	4.010%	($3,647)		($1,228,872)
	Feb-05	($1,228,872)	$445,658	$627,630	($181,972)	($1,410,844)	($1,319,858)	4.010%	($4,331)		($1,415,176)
	Mar-05	($1,415,176)	$456,825	$643,374	($186,549)	($1,601,725)	($1,508,450)	4.270%	($5,265)		($1,606,990)
	Apr-05	($1,606,990)	$412,416	$580,695	($168,279)	($1,775,270)	($1,691,130)	4.270%	($5,903)		($1,781,172)
	May-05	($1,781,172)	$371,547	$523,283	($151,736)	($1,932,909)	($1,857,041)	4.270%	($6,482)		($1,939,391)
	Jun-05	($1,939,391)	$379,551	$534,522	($154,971)	($2,094,362)	($2,016,877)	4.270%	($7,040)		($2,101,402)
	Jul-05	($2,101,402)	$477,583	$672,605	($195,022)	($2,296,424)	($2,198,913)	4.270%	($7,675)		($2,304,100)
	Aug-05	($2,304,100)	$282,269	$722,747	($440,478)	($2,744,578)	($2,524,339)	4.270%	($8,811)		($2,753,389)
	Sep-05	($2,753,389)	$516,597	$727,513	($210,916)	($2,964,305)	($2,858,847)	4.270%	($9,979)		($2,974,284)
**	Oct-05	($2,974,284)	$290,057		$290,057	($2,684,228)	($2,829,256)	4.270%	($9,876)		($2,694,103)
	Total	$0	$5,148,575	$7,767,907	($2,619,332)				($74,772)		

* Indicates prorated revenues for usage on and after October 1, 2004
** Indicates estimated revenues for September 2005 billed in October 2005.

Column (a) Column (j) from previous row; beginning balance from Docket No. 3648, filed November 10, 2004
Column (b) From Transition Revenues to Narragansett Electric Company for the former Newport Electric
Column (c) From CTC Bills to Narragansett Electric Company for the former Newport Electric
Column (d) Column (b) - Column (c)
Column (e) Column (a) + Column (d)
Column (f) (Column (a) + Column (e)) ÷ 2
Column (g) Customer Deposit Rate
Column (h) Column (f) * (1 + Column (g)^(1/12))
Column (i)
Column (j) Column (e) + Column (h) + Column (i)

Transition Charge Over Recovery
Incurred October 2003 through September 2004

Month	Beginning Over Recovery Balance (a)	Transition Charge Over Recovery Refund (b)	Ending Over Recovery Balance (c)		Interest Balance (d)	Monthly Interest Rate (e)	Monthly Interest (f)	Ending Balance w/ Interest (g)
Nov-2004	$437,110	$0	$437,110		$437,110	4.010%	$1,435	$438,545
Dec-2004	$438,545	$0	$438,545	(1)	$438,545	4.010%	$1,439	$439,984
Jan-05	$439,984	($15,593)	$424,391	(1)	$432,187	4.010%	$1,418	$425,809
Feb-05	$425,809	($32,302)	$393,508		$409,659	4.010%	$1,344	$394,852
Mar-05	$394,852	($32,961)	$361,891		$378,372	4.270%	$1,321	$363,212
Apr-05	$363,212	($29,990)	$333,223		$348,217	4.270%	$1,215	$334,438
May-05	$334,438	($28,059)	$306,379		$320,408	4.270%	$1,118	$307,497
Jun-05	$307,497	($30,666)	$276,831		$292,164	4.270%	$1,020	$277,851
Jul-05	$277,851	($36,041)	$241,810		$259,830	4.270%	$907	$242,717
Aug-05	$242,717	($39,208)	$203,509		$223,113	4.270%	$779	$204,287
Sep-05	$204,287	($38,758)	$165,530		$184,909	4.270%	$645	$166,175
Oct-05	$166,175	($32,529)	$133,646		$149,911	4.270%	$523	$134,169
Nov-05	$134,169	$0	$134,169		$134,169	4.270%	$468	$134,638
Dec-05	$134,638	$0	$134,638		$134,638	4.270%	$470	$135,108
Jan-06	$135,108	$0	$135,108	(2)	$135,108	4.270%	$472	$135,579

(1) Percentage of kWhs consumed on and after Jan 1, 2005 = 46.29%
(2) Percentage of kWhs billed in Jan 2006 and consumed prior to Jan 1, 2006 = n/a

(a) Prior Month Column (c); beginning balance per R.I.P.U.C. Docket No. 3648, Schedule JAL-3, page 1
(b) from Page 6
(c) Column (a) - Column (b)
(d) (Column (a) + Column (c)) ÷ 2
(e) Customer Deposit Rate
(f) Column (f) * (1 + Column (g)^(1/12))
(g) Column (c) + Column (f)

January 2005 Transition Charge Over Recovery Revenue

	kWh Sales (a)	Jan-05 Transition Over Recovery Factor (b)	Total Jan-05 Transition Over Recovery Revenue (c)
Jan-05	673,697,850	($0.00005)	($33,685)
Feb-05	646,032,306	($0.00005)	($32,302)
Mar-05	659,213,682	($0.00005)	($32,961)
Apr-05	599,792,608	($0.00005)	($29,990)
May-05	561,184,203	($0.00005)	($28,059)
Jun-05	613,326,982	($0.00005)	($30,666)
Jul-05	720,810,371	($0.00005)	($36,041)
Aug-05	784,167,871	($0.00005)	($39,208)
Sep-05	775,157,934	($0.00005)	($38,758)
Oct-05	650,577,703	($0.00005)	($32,529)
Nov-05		($0.00005)	$0
Dec-05		($0.00005)	$0
Jan-06		($0.00005)	$0
	6,683,961,510		($334,198)

(a) kWhs per Monthly SMB702 Report, Monthly Standard Offer, Open Access, Last Resort Service Revenue Reports
(b) Approved Transition Charge Over Recovery Factor for January 2005
(c) Column (a) x Column (b)

Exhibit JAL-4

Calculation of Proposed Transmission Adjustment Factor for January 2006

Calculation of Proposed Transmission Adjustment Factor for January 2006
Effective January 1, 2006 - December 31, 2006

(1)	Forecasted 2006 Transmission Expense	$52,832,798	
(2)	2006 Forecasted kWh Sales	8,079,436,209	
(3)	Average 2006 Transmission Expense per kWh		$0.00653
(4)	Uplift Recovery Factor		$0.00024
(5)	Implementation of 2006 under recovery factor		$0.00088
(6)	Estimated Average 2006 Transmission Charge		$0.00765
(7)	Projected Average Base Transmission Charge Revenue		$0.00394
(8)	Proposed 2006 Transmission Adjustment Factor		$0.00371
(9)	Current 2005 Transmission Adjustment Factor		$0.00239
(10)	Increase(Decrease) in 2006 Factor		$0.00132

(1) from Exhibit SLH-1
(2) from Company forecast
(3) Line (1) ÷ Line (2)
(4) from Exhibit JAL-5, Page 12
(5) from Exhibit JAL-5, Page 14
(6) Line (3) + Line (4) + Line (5)
(7) from Page 2
(8) Line (6) - Line (7)
(9) Current factor
(10) Line (8) - Line (9)

Projected 2006 Base Transmission Revenue

		A16	A60	E30	E40	C06	T	G02	G32	G62	R02	X01	Strlts	Total
	Projected Billing Determinants													
(1)	kW Demand							4,167,900.0	6,031,465.6	1,373,982.0		227,191.3		11,800,539.0
(2)	kWh Deliveries	2,818,133,472	237,617,777	1,723,104	7,088,274	542,930,045	16,018,847	1,503,206,314	2,201,484,954	652,641,470	4,578,720	26,127,000	67,886,131	8,079,436,108
	Base Transmission Charges													
(3)	Demand charges							$1.40	$1.27	$1.39		$1.34		
(4)	kWh charge	$0.00436	$0.00338	$0.00261	$0.00141	$0.00536	$0.00361				$0.00259		$0.00259	
	Base Transmission Revenue													
(5)	Demand Revenue							$5,835,060	$7,659,961	$1,909,835	$0	$304,436		$15,709,293
(6)	kWh Revenue	$12,287,062	$803,148	$4,497	$9,994	$2,910,105	$57,828	$0	$0	$0	$11,859	$0	$175,825	$16,260,319
(7)	Projected Base Transmission Revenue Before Discounts	$12,287,062	$803,148	$4,497	$9,994	$2,910,105	$57,828	$5,835,060	$7,659,961	$1,909,835	$11,859	$304,436	$175,825	$31,969,612
	Discounts													
(8)	kW Demand - Customers with HVM							55,141.3	1,536,817.4	1,313,526.8				
(9)	Demand Charge							$1.40	$1.27	$1.39				
(10)	Discount							($772)	($19,518)	($18,258)				($38,548)
(11)	kWh Deliveries - Customer with HVM							$18,639,758	$573,266,682	$626,666,339				
(12)	Transmission Adj Factor							$0.00239	$0.00239	$0.00239				
(13)	Discount							($445)	($13,701)	($14,977)				($29,124)
(14)	Total HVM Discount							($1,217)	($33,219)	($33,235)				($67,671)
(15)	Total Projected Base Transmission Revenue	$12,287,062	$803,148	$4,497	$9,994	$2,910,105	$57,828	$5,833,843	$7,626,743	$1,876,600	$11,859	$304,436	$175,825	$31,901,940
													Total Projected kWhs	8,079,436,108
													Average Base Transmission Revenue	$0.00394

(1) Projected kWhs times estimated class average load factor based on historical usage for the period November 2004 through October 2005.
(2) per Company forecast
(3) per current tariff
(4) per current tariff
(5) Line (1) x Line (3)
(6) Line (2) x Line (4)
(7) Line (5) + Line (6)
(8) Estimated based on histroical usage for the period November 2004 through October 2005
(9) per current tariff
(10) Line (8) x Line (9) x -0.01%
(11) Estimated based on histroical usage for the period November 2004 through October 2005
(12) per current tariff
(13) Line (11) x Line (12) x -0.01%
(14) Line (10) + Line (13)
(15) Line (7) + Line (14)

Exhibit JAL-5

Transmission Service Reconciliation

Transmission Service Reconciliation
October 2004 through September 2005

Base Transmission Reconciliation Balance @September 30, 2005

	Month	Over/(Under) Beginning Balance (a)	Transmission Revenue (b)	Transmission Adjustment (c)	Transmission Expense (d)	Monthly Over/(Under) (e)	Over/(Under) Ending Balance (f)
(1)	Oct-04	$0	$1,949,568	$213,668	$4,020,069	($1,856,833)	($1,856,833)
	Nov-04	($1,856,833)	$2,982,437		$4,253,498	($1,271,061)	($3,127,894)
	Dec-04	($3,127,894)	$3,314,722		$4,922,146	($1,607,424)	($4,735,318)
	Jan-05	($4,735,318)	$3,450,176	$4,575	$3,573,561	($118,810)	($4,854,128)
	Feb-05	($4,854,128)	$3,657,206		$3,962,337	($305,131)	($5,159,260)
	Mar-05	($5,159,260)	$3,671,135		$4,143,227	($472,092)	($5,631,351)
	Apr-05	($5,631,351)	$3,366,994		$3,967,781	($600,787)	($6,232,139)
	May-05	($6,232,139)	$3,181,800		$4,383,181	($1,201,381)	($7,433,520)
	Jun-05	($7,433,520)	$3,485,530		$5,213,318	($1,727,788)	($9,161,307)
	Jul-05	($9,161,307)	$4,050,112		$4,684,812	($634,700)	($9,796,007)
	Aug-05	($9,796,007)	$4,394,570	($7,570)	$4,658,493	($271,493)	($10,067,501)
	Sep-05	($10,067,501)	$4,493,145		$3,721,332	$771,813	($9,295,687)
(2)	Oct-05	($9,295,687)	$2,460,557			$2,460,557	($6,835,130)
	Total	$0	$44,457,952	$210,673	$51,503,755	($6,835,130)	($6,835,130)
	Interest through September 2005						($142,228)
	Base Transmission Reconciliation Balance with Interest						**($6,977,358)**

(1) Indicates estimated revenues for consumption on and after October 2004
(2) Indicates estimated revenues for September 2005 usage billed in October 2005

Column Descriptions:

(a) Prior Month Column (f); beginning balance per order in RIPUC Docket No. 3648.
(b) from Page 2
(c) October 2004: True-up of estimated September 2004 expenses of $3,334,733 to actual expenses of $3,121,064
Jan 2005: from page 5
Aug 2005: Customer billing error resulting in reduction of transmission revenues
(d) from Page 4; expenses for August 2005 and September 2005 have been estimated
(e) Column (b) + Column (c) - Column (d)
(f) Column (a) + Column (e)

Total Transmission Revenue

	Total Transmission Revenue (a)	Less 2004 Transmission Adjustment Revenue (b)	Less 2005 Transmission Adjustment Revenue (c)	Less Uplift Recovery Revenue (c)	Base Transmission Revenue (d)	Less HVM Credit (e)	Net Base Transmission Revenue (f)
Oct-04	$2,751,521	($405,584)	$0	$0	$3,157,104	($4,186)	$3,152,918
Nov-04	$2,601,580	($384,712)	$0	$0	$2,986,292	($3,855)	$2,982,437
Dec-04	$2,887,084	($431,577)	$0	$0	$3,318,662	($3,940)	$3,314,722
Jan-05	$3,486,901	($191,935)	$149,440	$74,720	$3,454,677	($4,501)	$3,450,176
Feb-05	$4,126,530	$0	$309,642	$155,048	$3,661,840	($4,634)	$3,657,206
Mar-05	$4,150,096	$0	$315,929	$158,211	$3,675,955	($4,820)	$3,671,135
Apr-05	$3,802,953	$0	$287,442	$143,950	$3,371,561	($4,567)	$3,366,994
May-05	$3,589,838	$0	$268,928	$134,684	$3,186,226	($4,426)	$3,181,800
Jun-05	$3,931,310	$0	$293,933	$147,198	$3,490,178	($4,648)	$3,485,530
Jul-05	$4,573,711	$0	$345,466	$172,994	$4,055,251	($5,139)	$4,050,112
Aug-05	$4,963,772	$0	$375,880	$188,200	$4,399,691	($5,121)	$4,394,570
Sep-05	$4,869,873	$0	$371,548	$186,038	$4,498,325	($5,180)	$4,493,145
Oct-05	$4,113,798	$0	$311,782	$156,139	$3,802,017	($4,861)	$3,797,156
Total	$49,848,966	($1,413,808)	$3,029,988	$1,517,183	$47,057,780	($59,878)	$46,997,902

(a) Monthly SMB702 Report, Monthly Standard Offer, Open Access, Last Resort Service Revenue Reports
(b) from Page 6, Column (c)
(c) from Page 9, Column (c)
(d) Column (a) - Column (b) - Column (c)
(e) from Page 3
(f) Column (d) - Column (e)

Transmission Revenue - HVM Discount

	Transmission Revenues - Primary Metered Customers (a)	Transmission kWh Deliveries - Primary Metered Customers (b)	HVM Discount (c)	Less 2004 Transmission Adjustment HVM Revenue (d)	Less 2005 Transmission Adjustment HVM Revenue (e)	Less Uplift Adjustment HVM Revenue (f)	Base HVM Discount (g)
Oct-04	$354,114	100,761,107	($3,541)	$645			($4,186)
Nov-04	$324,411	95,475,065	($3,244)	$611			($3,855)
Dec-04	$331,179	98,126,220	($3,312)	$628			($3,940)
Jan-05	$459,103	112,855,310	($4,591)	$722	(542)	(271)	($4,501)
Feb-05	$531,454	94,474,830	($5,315)		(453)	(227)	($4,634)
Mar-05	556,014	102,794,160	($5,560)		(493)	(247)	($4,820)
Apr-05	525,469	95,523,390	($5,255)		(459)	(229)	($4,567)
May-05	508,766	91,853,710	($5,088)		(441)	(220)	($4,426)
Jun-05	534,420	96,689,690	($5,344)		(464)	(232)	($4,648)
Jul-05	592,382	109,024,610	($5,924)		(523)	(262)	($5,139)
Aug-05	590,224	108,439,455	($5,902)		(521)	(260)	($5,121)
Sep-05	597,208	110,017,525	($5,972)		(528)	(264)	($5,180)
Oct-05	560,443	103,277,535	($5,604)		(496)	(248)	($4,861)

Notes:

(a) CIS System Data
(b) CIS System Data
(c) Column (a) x -1%
(d) from Page 7
(e) from Page 10
(f) from Page 13
(g) Column (c) - Column (d) - Column (e) - Column (f

Transmission Expense

	NEPOOL PTF Expenses	NEP Non-PTF Expenses	Other NEPOOL Charges	ISO Tariff Expenses	Total Transmission Expense
October-04	$1,726,127	$1,217,254	$982,174	$94,514	$4,020,069
November-04	$1,812,263	$1,340,767	$877,071	$223,397	$4,253,498
December-04	$2,123,439	$2,166,921	$448,511	$183,275	$4,922,146
January-05	$2,045,825	$1,013,897	$334,214	$179,625	$3,573,561
February-05	$2,009,742	$1,471,897	$379,906	$100,792	$3,962,337
March-05	$2,057,045	$1,201,942	$791,429	$92,811	$4,143,227
April-05	$1,728,599	$1,065,045	$1,100,256	$73,881	$3,967,781
May-05	$1,701,966	$1,462,178	$1,113,337	$105,700	$4,383,181
June-05	$2,807,326	$1,751,169	$536,159	$118,664	$5,213,318
July-05	$3,085,368	$986,289	$480,642	$132,513	$4,684,812
August-05 (estimated)	$3,108,850	$1,214,765	$192,469	$142,409	$4,658,493
September-05 (estimated)	$2,358,098	$1,180,967	$0	$182,267	$3,721,332
Total	$26,564,648	$16,073,091	$7,236,168	$1,629,848	$51,503,755

Source: Monthly NEP, NEPOOL and ISO Bills

Transmission Over Recovery Reconciliation
Incurred October 2002 - September 2003

Month	Beginning Over Recovery Balance (a)	Transmission Adjustment Revenue (b)	Ending Over Recovery Balance (c)	
Jan-04	$4,851,962	$210,281	$4,641,681	(1)
Feb-04	$4,641,681	$421,945	$4,219,735	
Mar-04	$4,219,735	$405,063	$3,814,673	
Apr-04	$3,814,673	$380,353	$3,434,320	
May-04	$3,434,320	$361,451	$3,072,868	
Jun-04	$3,072,868	$398,888	$2,673,980	
Jul-04	$2,673,980	$433,958	$2,240,022	
Aug-04	$2,240,022	$451,741	$1,788,281	
Sep-04	$1,788,281	$467,691	$1,320,591	
Oct-04	$1,320,591	$405,584	$915,007	
Nov-04	$915,007	$384,712	$530,295	
Dec-04	$530,295	$431,577	$98,718	
Jan-05	$98,718	$191,935	($93,217)	(2)

Ending Balance	($93,217)
Interest for the period January 2004 through December 2004	$97,792
Ending Balance with Interest	$4,575

(1) Percentage kWhs consumed on or after January 1, 2004 = 46.40%
(2) Percentage kWhs consumed prior to January 1, 2005 = 44.59%

(a) Prior Month Column (c); beginning balance from Docket No. 3571, Hearing Update, Exhibit JAL-5, page 12 of 12
(b) from Page 6
(c) Column (a) - Column (b)

January 2004 Transmission Cost Adjustment Recovery

	kWh Sales (a)	Jan-2004 Transmission Adjustment Factor (b)	Total Jan-2004 Transmission Adjustment Revenue (c)	Less HMV Discount (d)	Net 2004 Transmission Adjustment Revenue (e)
Jan-04	709,525,073	($0.00064)	($454,096)	($903)	($453,193)
Feb-04	660,606,962	($0.00064)	($422,788)	($843)	($421,945)
Mar-04	634,260,689	($0.00064)	($405,927)	($864)	($405,063)
Apr-04	595,612,924	($0.00064)	($381,192)	($839)	($380,353)
May-04	566,108,513	($0.00064)	($362,309)	($858)	($361,451)
Jun-04	624,802,955	($0.00064)	($399,874)	($986)	($398,888)
Jul-04	679,563,014	($0.00064)	($434,920)	($963)	($433,958)
Aug-04	707,343,909	($0.00064)	($452,700)	($959)	($451,741)
Sep-04	732,335,738	($0.00064)	($468,695)	($1,004)	($467,691)
Oct-04	634,731,915	($0.00064)	($406,228)	($645)	($405,584)
Nov-04	602,067,795	($0.00064)	($385,323)	($611)	($384,712)
Dec-04	675,320,438	($0.00064)	($432,205)	($628)	($431,577)
Jan-05	673,697,850	($0.00064)	($431,167)	($722)	($430,444)
Total	7,125,845,740		($4,560,541)	($9,079)	($4,551,462)

(a) kWhs per Monthly SMB702 Report, Monthly Standard Offer, Open Access, Last Resort Service Revenue Reports
(b) RIPUC Docket No. 3571, Hearing Update, Exhibit JAL-5, page 12 of 12
(c) Column (a) x Column (b)
(d) from Page 7
(e) Column (c) - Column (d)

High Voltage Metering Discount Relating to January 2004 Transmission Adjustment Factor Recovery
kWh's Subject to Discount

	kWh (a)	1% Discount (b)	Jan-2004 Transmission Adjustment Factor (c)	HVM Discount (d)
Jan-04	141,126,024	1,411,260	($0.00064)	($903)
Feb-04	131,755,843	1,317,558	($0.00064)	($843)
Mar-04	135,042,146	1,350,421	($0.00064)	($864)
Apr-04	131,124,246	1,311,242	($0.00064)	($839)
May-04	134,074,026	1,340,740	($0.00064)	($858)
Jun-04	154,013,045	1,540,130	($0.00064)	($986)
Jul-04	150,404,414	1,504,044	($0.00064)	($963)
Aug-04	149,847,765	1,498,478	($0.00064)	($959)
Sep-04	156,921,262	1,569,213	($0.00064)	($1,004)
Oct-04	100,761,107	1,007,611	($0.00064)	($645)
Nov-04	95,475,065	954,751	($0.00064)	($611)
Dec-04	98,126,220	981,262	($0.00064)	($628)
Jan-05	112,855,310	1,128,553	($0.00064)	($722)
Total	1,418,644,606	14,186,446		($9,079)

(a) from CIS
(b) Column (a) x 1%
(c) Approved Transmission Adjustment Factor for Jan 2004
(d) Column (b) x Column (c)

Transmission Under Recovery Reconciliation
Incurred October 2003 - September 2004

Approved under collection:	$3,758,084
Interest through Dec 2004:	$37,675
Under Recovery Beginning Balance:	$3,795,759

Month	Beginning Under Recovery Balance (a)	Transmission Adjustment Revenue (b)	Ending Under Recovery Balance (c)	
Jan-05	$3,795,759	$149,440	$3,646,319	(1)
Feb-05	$3,646,319	$309,642	$3,336,677	
Mar-05	$3,336,677	$315,929	$3,020,748	
Apr-05	$3,020,748	$287,442	$2,733,306	
May-05	$2,733,306	$268,928	$2,464,379	
Jun-05	$2,464,379	$293,933	$2,170,446	
Jul-05	$2,170,446	$345,466	$1,824,980	
Aug-05	$1,824,980	$375,880	$1,449,100	
Sep-05	$1,449,100	$371,548	$1,077,552	
Oct-05	$1,077,552	$311,782	$765,771	
Nov-05	$765,771	$0	$765,771	
Dec-05	$765,771	$0	$765,771	
Jan-06	$765,771	$0	$765,771	(2)

Ending Balance	$765,771
Interest through December 2005	$96,400
Total Ending Balance w/ Interest	$862,171

(1) Percentage of kWhs consumed on and after Jan 1, 2005 = 46.29%
(2) Percentage of kWhs billed in Jan 2005 and consumed prior to Jan 1, 2006 = n/a

(a) Prior Month Column (c); beginning balance per R.I.P.U.C. Docket No. 3648, Schedule JAL-5, page 11
(b) from Page 9
(c) Column (a) - Column (b)

January 2005 Transmission Cost Adjustment Recovery

	kWh Sales (a)	Jan-05 Transmission Adjustment Factor (b)	Total Jan-05 Transmission Adjustment Revenue (c)	Less HMV Discount (d)	Net Jan-05 Transmission Adjustment Revenue (e)
Jan-05	673,697,850	$0.00048	$323,375	$542	$322,833
Feb-05	646,032,306	$0.00048	$310,096	$453	$309,642
Mar-05	659,213,682	$0.00048	$316,423	$493	$315,929
Apr-05	599,792,608	$0.00048	$287,900	$459	$287,442
May-05	561,184,203	$0.00048	$269,368	$441	$268,928
Jun-05	613,326,982	$0.00048	$294,397	$464	$293,933
Jul-05	720,810,371	$0.00048	$345,989	$523	$345,466
Aug-05	784,167,871	$0.00048	$376,401	$521	$375,880
Sep-05	775,157,934	$0.00048	$372,076	$528	$371,548
Oct-05	650,577,703	$0.00048	$312,277	$496	$311,782
Nov-05		$0.00048	$0	$0	$0
Dec-05		$0.00048	$0	$0	$0
Jan-06		$0.00048	$0	$0	$0
Total	6,683,961,510		$3,208,302	$4,920	$3,203,382

(a) kWhs per Monthly SMB702 Report, Monthly Standard Offer, Open Access, Last Resort Service Revenue Reports
(b) Approved Transmission Adjustment Factor for January 2005
(c) Column (a) x Column (b)
(d) from Page 10
(e) Column (c) - Column (d)

High Voltage Metering Discount Relating to January 2005 Transmission Adjustment Factor Recovery
kWh's Subject to Discount

	kWh (a)	1% Discount (b)	Jan-05 Transmission Adjustment Factor (c)	HVM Discount (d)
Jan-05	112,855,310	1,128,553	$0.00048	$542
Feb-05	94,474,830	944,748	$0.00048	$453
Mar-05	102,794,160	1,027,942	$0.00048	$493
Apr-05	95,523,390	955,234	$0.00048	$459
May-05	91,853,710	918,537	$0.00048	$441
Jun-05	96,689,690	966,897	$0.00048	$464
Jul-05	109,024,610	1,090,246	$0.00048	$523
Aug-05	108,439,455	1,084,395	$0.00048	$521
Sep-05	110,017,525	1,100,175	$0.00048	$528
Oct-05	103,277,535	1,032,775	$0.00048	$496
Nov-05	0	0	$0.00048	$0
Dec-05	0	0	$0.00048	$0
Jan-06	0	0	$0.00048	$0
Total	1,024,950,215	10,249,502		$4,920

(a) from CIS
(b) Column (a) x 1%
(c) Approved Transmission Adjustment Factor for 2005
(d) Column (b) x Column (c)

Recovery of Deferred Uplift Charges
Incurred January 1999 through May 2004

Month	Beginning Under Recovery Balance (a)	Transmission Adjustment Revenue (b)	Ending Under Recovery Balance (c)		Interest Balance (d)	Monthly Interest Rate (e)	Monthly Interest (f)	Ending Balance w/ Interest (g)
Jan-05	$5,649,701	$74,720	$5,574,981	(1)	$5,612,341	0.334%	$18,755	$5,593,736
Feb-05	$5,593,736	$154,821	$5,438,915		$5,516,325	0.334%	$18,434	$5,457,348
Mar-05	$5,457,348	$157,965	$5,299,384		$5,378,366	0.356%	$19,138	$5,318,522
Apr-05	$5,318,522	$143,721	$5,174,801		$5,246,661	0.356%	$18,669	$5,193,470
May-05	$5,193,470	$134,464	$5,059,006		$5,126,238	0.356%	$18,241	$5,077,247
Jun-05	$5,077,247	$146,966	$4,930,281		$5,003,764	0.356%	$17,805	$4,948,086
Jul-05	$4,948,086	$172,733	$4,775,353		$4,861,720	0.356%	$17,300	$4,792,653
Aug-05	$4,792,653	$187,940	$4,604,713		$4,698,683	0.356%	$16,719	$4,621,432
Sep-05	$4,621,432	$185,774	$4,435,658		$4,528,545	0.356%	$16,114	$4,451,772
Oct-05	$4,451,772	$155,891	$4,295,882		$4,373,827	0.356%	$15,564	$4,311,445
Nov-05	$4,311,445	$0	$4,311,445		$4,311,445	0.356%	$15,342	$4,326,787
Dec-05	$4,326,787	$0	$4,326,787		$4,326,787	0.356%	$15,396	$4,342,183
Jan-06	$4,342,183	$0	$4,342,183	(2)	$4,342,183	0.356%	$15,451	$4,357,634

(1) Percentage of kWhs consumed on and after Jan 1, 2005 = 46.29%
(2) Percentage of kWhs billed in Jan 2006 and consumed prior to Jan 1, 2006 = n/a

(a) Prior Month Column (c); beginning balance per R.I.P.U.C. Docket No. 3648, Schedule JAL-5, page 11
(b) from Page 12
(c) Column (a) - Column (b)
(d) (Column (a) + Column (c)) ÷ 2
(e) Customer deposits rate ÷ 12
(f) Column (d) * Column (e)
(g) Column (c) + Column (f)

January 2005 Transmission Cost Adjustment Recovery

	kWh Sales (a)	Jan-05 Transmission Adjustment Factor (b)	Total Jan-05 Transmission Adjustment Revenue (c)	Less HMV Discount (d)	Net Jan-05 Transmission Adjustment Revenue (e)
Jan-05	673,697,850	$0.00024	$161,687	($271)	$161,417
Feb-05	646,032,306	$0.00024	$155,048	($227)	$154,821
Mar-05	659,213,682	$0.00024	$158,211	($247)	$157,965
Apr-05	599,792,608	$0.00024	$143,950	($229)	$143,721
May-05	561,184,203	$0.00024	$134,684	($220)	$134,464
Jun-05	613,326,982	$0.00024	$147,198	($232)	$146,966
Jul-05	720,810,371	$0.00024	$172,994	($262)	$172,733
Aug-05	784,167,871	$0.00024	$188,200	($260)	$187,940
Sep-05	775,157,934	$0.00024	$186,038	($264)	$185,774
Oct-05	650,577,703	$0.00024	$156,139	($248)	$155,891
Nov-05		$0.00024	$0	$0	$0
Dec-05		$0.00024	$0	$0	$0
Jan-06		$0.00024	$0	$0	$0
Total	6,683,961,510		$1,604,151	($2,460)	$1,601,691

(a) kWhs per Monthly SMB702 Report, Monthly Standard Offer, Open Access, Last Resort Service Revenue Reports
(b) Approved Factor for January 2005 through December 2007
(c) Column (a) x Column (b)
(d) from Page 13
(e) Column (c) - Column (d)

High Voltage Metering Discount Relating to January 2005 Transmission Adjustment Factor Recovery
kWh's Subject to Discount

	kWh (a)	1% Discount (b)	Jan-05 Transmission Adjustment Factor (c)	HVM Discount (d)
Jan-05	112,855,310	1,128,553	$0.00024	($271)
Feb-05	94,474,830	944,748	$0.00024	($227)
Mar-05	102,794,160	1,027,942	$0.00024	($247)
Apr-05	95,523,390	955,234	$0.00024	($229)
May-05	91,853,710	918,537	$0.00024	($220)
Jun-05	96,689,690	966,897	$0.00024	($232)
Jul-05	109,024,610	1,090,246	$0.00024	($262)
Aug-05	108,439,455	1,084,395	$0.00024	($260)
Sep-05	110,017,525	1,100,175	$0.00024	($264)
Oct-05	103,277,535	1,032,775	$0.00024	($248)
Nov-05	0	0	$0.00024	$0
Dec-05	0	0	$0.00024	$0
Jan-06	0	0	$0.00024	$0
Total	1,024,950,215	10,249,502		($2,460)

(a) from CIS
(b) Column (a) x 1%
(c) Approved Factor for January 2005 through December 2007
(d) Column (b) x Column (c)

Calculation of Interest and Under Recovery Factor for the period October 2004 through September 2005

Month	Beginning Balance (1)	Surcharge/ (Refund) (2)	Ending Balance (3)	Interest Rate (4)	Interest (5)
Nov-2005	$6,977,358	$0	$6,977,358	0.356%	$24,828
Dec-2005	$7,002,186	$0	$7,002,186	0.356%	$24,916
Jan-2006	$7,027,102	$585,592	$6,441,510	0.356%	$23,963
Feb-2006	$6,465,473	$587,770	$5,877,703	0.356%	$21,961
Mar-2006	$5,899,663	$589,966	$5,309,697	0.356%	$19,943
Apr-2006	$5,329,640	$592,182	$4,737,458	0.356%	$17,911
May-2006	$4,755,369	$594,421	$4,160,948	0.356%	$15,864
Jun-2006	$4,176,812	$596,687	$3,580,124	0.356%	$13,801
Jul-2006	$3,593,925	$598,988	$2,994,938	0.356%	$11,723
Aug-2006	$3,006,660	$601,332	$2,405,328	0.356%	$9,629
Sep-2006	$2,414,957	$603,739	$1,811,218	0.356%	$7,519
Oct-2006	$1,818,737	$606,246	$1,212,491	0.356%	$5,393
Nov-2006	$1,217,884	$608,942	$608,942	0.356%	$3,250
Dec-2006	$612,192	$612,192	$0	0.356%	$1,089
					$152,045

Total Surcharge/(Refund) to Customers with Interest	$7,129,403
Total Forecasted kWh Sales for 12 months ending Dec 2006	8,079,436,209
Reconciliation Transmission Adjustment Factor per kWh	$0.00088

Notes:

1 Column (3) + Column (5) of previous month
2 For Jan 2006, (Column (1)) ÷ 12. For Feb 2006, (Column (1))÷11, etc.
3 Column (1) - Column (2)
4 Current Rate for Customer Deposits
5 ((Column (1) + Column (3))÷2)* Column (4)

Exhibit JAL-6

Last Resort Service Reconciliation

Last Resort Service Reconciliation

	Month	(Under)/Over Beginning Balance (a)	Last Resort Revenue (b)	Last Resort Expense (c)	Monthly (Under)/Over (d)	Adjustments (e)	(Under)/Over Ending Balance (g)
*	Oct-04	$72,937	$226,724	$734,265	($507,542)		($434,605)
	Nov-04	($434,605)	$1,003,075	$597,338	$405,737		($28,867)
	Dec-04	($28,867)	$819,009	$986,347	($167,338)		($196,205)
	Jan-05	($196,205)	$1,282,698	$1,422,523	($139,825)		($336,030)
	Feb-05	($336,030)	$1,329,431	$1,059,675	$269,756		($66,274)
	Mar-05	($66,274)	$971,573	$770,129	$201,444		$135,170
	Apr-05	$135,170	$629,075	$600,441	$28,633		$163,804
	May-05	$163,804	$622,848	$681,299	($58,450)		$105,353
	Jun-05	$105,353	$761,502	$853,396	($91,895)		$13,459
	Jul-05	$13,459	$954,476	$974,748	($20,272)		($6,813)
	Aug-05	($6,813)	$971,267	$1,055,188	($83,921)		($90,734)
	Sep-05	($90,734)	$1,049,453	$1,020,209	$29,245		($61,489)
**	Oct-05	($61,489)	$678,545	$0	$678,545		$617,056
	Totals	$72,937	$11,299,676	$10,755,557	$544,119	$0	$617,056
	Interest						$14,358
	Ending Balance with Interest						$631,413

* Indicates revenue for consumption on and after October 1, 2004 (28.77%)
** Indicates revenue for consumption in September 2004 but billed in October 2005 (65.43%)

Column (a) Column (g) from previous row; October 2003 beginning balance per RIPUC Docket No. 3648.
Column (b) Pages 2 and 3
Column (c) Last Resort bills
Column (d) Column (b) - Column (c)
Column (e)
Column (g) Column (a) + Column (d) + Column (e)

Last Resort Service Reconciliation - Residential

	Month	(Under)/Over Beginning Balance (a)	Last Resort Revenue (b)	Last Resort Expense (c)	Monthly (Under)/Over (d)	Adjustments (e)	(Under)/Over Ending Balance (g)
*	Oct-04	($1,767)	$8,841	$26,343	($17,502)		($19,269)
	Nov-04	($19,269)	$28,462	$32,481	($4,020)		($23,288)
	Dec-04	($23,288)	$46,511	$44,659	$1,851		($21,437)
	Jan-05	($21,437)	$45,708	$47,391	($1,683)		($23,120)
	Feb-05	($23,120)	$47,476	$39,483	$7,994		($15,126)
	Mar-05	($15,126)	$52,461	$33,032	$19,429		$4,303
	Apr-05	$4,303	$41,096	$26,029	$15,066		$19,370
	May-05	$19,370	$34,496	$27,053	$7,443		$26,813
	Jun-05	$26,813	$35,244	$37,747	($2,504)		$24,309
	Jul-05	$24,309	$44,966	$47,452	($2,487)		$21,822
	Aug-05	$21,822	$48,410	$57,417	($9,007)		$12,815
	Sep-05	$12,815	$46,150	$40,470	$5,680		$18,495
**	Oct-05	$18,495	$25,681	$0	$25,681		$44,176
	Totals	($1,767)	$505,502	$459,558	$45,943	$0	$44,176
	Interest						$882
	Ending Balance with Interest						$45,059

* Indicates revenue for consumption on and after October 1, 2004 (28.77%)
** Indicates revenue for consumption in September 2004 but billed in October 2005 (65.43%)

Column (a) Column (g) from previous row; October 2003 beginning balance per RIPUC Docket No. 3648.
Column (b) Monthly revenue reports
Column (c) Last Resort bills
Column (d) Column (b) - Column (c)
Column (e)
Column (g) Column (a) + Column (d) + Column (e)

Last Resort Service Reconciliation - Commercial & Industrial

	Month	(Under)/Over Beginning Balance (a)	Last Resort Revenue (b)	Last Resort Expense (c)	Monthly (Under)/Over (d)	Adjustments (e)	(Under)/Over Ending Balance (g)
*	Oct-04	$74,704	$217,882	$707,922	($490,040)		($415,336)
	Nov-04	($415,336)	$974,613	$564,856	$409,757		($5,579)
	Dec-04	($5,579)	$772,498	$941,688	($169,189)		($174,769)
	Jan-05	($174,769)	$1,236,991	$1,375,133	($138,142)		($312,911)
	Feb-05	($312,911)	$1,281,955	$1,020,192	$261,763		($51,148)
	Mar-05	($51,148)	$919,112	$737,097	$182,015		$130,867
	Apr-05	$130,867	$587,979	$574,412	$13,567		$144,434
	May-05	$144,434	$588,352	$654,245	($65,893)		$78,541
	Jun-05	$78,541	$726,258	$815,649	($89,391)		($10,850)
	Jul-05	($10,850)	$909,510	$927,295	($17,785)		($28,635)
	Aug-05	($28,635)	$922,858	$997,771	($74,913)		($103,549)
	Sep-05	($103,549)	$1,003,303	$979,739	$23,564		($79,984)
**	Oct-05	($79,984)	$652,864	$0	$652,864		$572,880
	Totals	$74,704	$10,794,175	$10,295,999	$498,176	$0	$572,880
	Interest						$13,475
	Ending Balance with Interest						$586,355

* Indicates revenue for consumption on and after October 1, 2004 (28.77%)
** Indicates revenue for consumption in September 2004 but billed in October 2005 (65.43%)

Column (a) Column (g) from previous row; October 2003 beginning balance per RIPUC Docket No. 3648.
Column (b) Monthly revenue reports
Column (c) Last Resort bills
Column (d) Column (b) - Column (c)
Column (e)
Column (g) Column (a) + Column (d) + Column (e)

Summary of Last Resort Service Revenues

	Residential Last Resort Revenues (a)	C&I Last Resort Revenues (b)	C&I HVM Discount (c)	C&I Net Revenues (d)	Total Last Resort Revenues (e)
Oct-04	$30,730	$759,870	(2,545)	757,325	$788,056
Nov-04	$28,462	$979,909	(5,296)	974,613	$1,003,075
Dec-04	$46,511	$776,778	(4,279)	772,498	$819,009
Jan-05	$45,708	$1,242,287	(5,297)	1,236,991	$1,282,698
Feb-05	$47,476	$1,287,990	(6,036)	1,281,955	$1,329,431
Mar-05	$52,461	$923,950	(4,838)	919,112	$971,573
Apr-05	$41,096	$590,653	(2,674)	587,979	$629,075
May-05	$34,496	$590,945	(2,593)	588,352	$622,848
Jun-05	$35,244	$728,799	(2,541)	726,258	$761,502
Jul-05	$44,966	$913,825	(4,315)	909,510	$954,476
Aug-05	$48,410	$927,067	(4,209)	922,858	$971,267
Sep-05	$46,150	$1,007,655	(4,352)	1,003,303	$1,049,453
Oct-05	$39,249	$1,001,801	(3,996)	997,805	$1,037,055
	$540,959	$11,731,529	($52,970)	$11,678,559	$12,219,518

(a) Company revenue reports
(b) Company revenue reports
(c) from CIS

Last Resort Service Revenue - HVM Discount

	Last Resort Revenues - Primary Metered Customers	HVM Discount
	(a)	(b)
Oct-04	$254,527	$2,545
Nov-04	$529,569	$5,296
Dec-04	$427,949	$4,279
Jan-05	$529,674	$5,297
Feb-05	$603,572	$6,036
Mar-05	$483,786	$4,838
Apr-05	$267,385	$2,674
May-05	$259,312	$2,593
Jun-05	$254,074	$2,541
Jul-05	$431,481	$4,315
Aug-05	$420,909	$4,209
Sep-05	$435,236	$4,352
Oct-05	$399,574	$3,996

Notes:

(a) CIS System Data
(b) Column (a) x 1%

Exhibit JAL-7

Tariff Cover Sheets

R.I.P.U.C. No. 1170

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$2.75
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.436¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	3.379¢ (Eff. Jan 1, 2006) 3.378¢ (Eff. Jan 1, 2007) 3.377¢ (Eff. Jan 1, 2008) 3.376¢ (Eff. Jan 1, 2009)
Minimum Charge per month	$2.75
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.338¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charges per kWh	
December through March	
First 450 kWhs	1.688¢
Next 750 kWhs	3.055¢
kWhs in excess of 1200 kWhs	2.548¢
April through November	
First 450 kWhs	1.688¢
kWhs in excess of 450 kWhs	3.055¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
C&I Back-Up Service Rate (B-32)
Retail Delivery Service

Effective
January 1, 2006

R.I.P.U.C. No. 1172

Monthly Charge As Adjusted

	Rates for Back-Up Service	Rates for Supplemental Service
Rates for Retail Delivery Service		
Customer Charge per month	$236.43	n/a
Transmission Demand Charge per kW	n/a	$1.27
Distribution Demand Charge per kW	$5.15	$2.02 (Eff. January 1, 2006)
	$5.13	$2.01 (Eff. January 1, 2007)
	$5.12	$2.00 (Eff. January 1, 2008)
	$5.11	$1.99 (Eff. January 1, 2009)
Distribution Demand Charge per kW (Applicable to former Auxiliary Service Customers)		
	$2.07	$2.02 (Eff. January 1, 2006)
	$3.09	$2.01 (Eff. January 1, 2007)
	$4.11	$2.00 (Eff. January 1, 2008)
	$5.11	$1.99 (Eff. January 1, 2009)
Transmission Adjustment Factor per kWh	n/a	0.371¢
Distribution Energy Charge per kWh	n/a	0.889¢
Non-bypassable Transition Charge per kWh	n/a	0.575¢
C&LM Adjustment per kWh	n/a	0.230¢
Rates for Standard Offer Service or Last Resort Service (Optional)		
Standard Offer per kWh	n/a	per Standard Offer Service tariff
Last Resort per kWh	n/a	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
3,000 kW Back-Up Service Rate (B-62)
Retail Delivery Service

Effective
January 1, 2006

R.I.P.U.C. No. 1173

Monthly Charge As Adjusted

	Rates for Back-Up Service	Rates for Supplemental Service
Rates for Retail Delivery Service		
Customer Charge per month	$17,118.72	n/a
Distribution Demand Charge per kW	$2.26	$2.26 (Eff. January 1, 2006)
	$2.25	$2.25 (Eff. January 1, 2007)
	$2.24	$2.24 (Eff. January 1, 2008)
	$2.22	$2.22 (Eff. January 1, 2009)
Distribution Demand Charge per kW (Applicable to former Auxiliary Service Customers)		
	$0.89	$2.26 (Eff. January 1, 2006)
	$1.33	$2.25 (Eff. January 1, 2007)
	$1.77	$2.24 (Eff. January 1, 2008)
	$2.22	$2.22 (Eff. January 1, 2009)
Transmission Demand Charge per kW	n/a	$1.39
Transmission Adjustment Factor per kWh	n/a	0.371¢
Non-bypassable Transition Charge per kWh	n/a	0.575¢
C&LM Adjustment per kWh	n/a	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	n/a	per Standard Offer Service tariff
Last Resort per kWh	n/a	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

R.I.P.U.C. No. 1174

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$6.00
Unmetered Charge per month	$1.83
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.536¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	3.652¢ (Eff. January 1, 2006) 3.643¢ (Eff. January 1, 2007) 3.634¢ (Eff. January 1, 2008) 3.624¢ (Eff. January 1, 2009)
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

R.I.P.U.C. No. 1175

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$2.75
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.261¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	2.300¢ (Eff. January 1, 2006) 2.658¢ (Eff. January 1, 2007) 3.017¢ (Eff. January 1, 2008) 3.376¢ (Eff. January 1, 2009)
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Storage Cooling Rate (E-40)
Retail Delivery Service

Effective
January 1, 2006

R.I.P.U.C. No 1190

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$75.15
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.141¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	
Peak/Shoulder	2.536¢
Off Peak	0.949¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
General C&I Rate (G-02)
Retail Delivery Service

Effective
January 1, 2006

R.I.P.U.C. No. 1176

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$103.41
Transmission Charge per kW in excess of 10 kW	$1.40
Distribution Charge per kW in excess of 10 kW	$3.22
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	0.777¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

R.I.P.U.C. No. 1177

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$236.43
Transmission Charge per kW	$1.27
Distribution Charge per kW	$2.02 (Eff. January 1, 2006) $2.01 (Eff. January 1, 2007) $2.00 (Eff. January 1, 2008) $1.99 (Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	0.889¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

R.I.P.U.C. No. 1178

Monthly Charge As Adjusted

Rates for Retail Delivery Services

Customer Charge per month	$17,118.72
Transmission Charge per kW	$1.39
Distribution Charge per kW	$2.26 (Eff. January 1, 2006) $2.25 (Eff. January 1, 2007) $2.24 (Eff. January 1, 2008) $2.22 (Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

Monthly Charge as Adjusted

Rates for Retail Delivery Service

Unmetered Charge per month	$0.72	(Eff. January 1, 2006)
	$1.08	(Eff. January 1, 2007)
	$1.44	(Eff. January 1, 2008)
	$1.83	(Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢	
Transmission Charge per kWh	0.259¢	
Transmission Adjustment Factor per kWh	0.371¢	
Distribution Charge per kWh	1.969¢	(Eff. January 1, 2006)
	2.520¢	(Eff. January 1, 2007)
	3.071¢	(Eff. January 1, 2008)
	3.624¢	(Eff. January 1, 2009)
Conservation and Load Management Adjustment per kWh	0.230¢	

Rates for Standard Offer Service or Last Resort (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

Effective
January 1, 2006

Limited Service - Private Lighting (S-10)
Retail Delivery Service

R.I.P.U.C. No. 1180

Luminaire Type/Lumens		Code	Annual kWh
Incandescent			
1,000		10	440
Mercury Vapor			
8,000	Post Top	2	908
4,000		3	561
8,000		4	908
22,000		5	1,897
63,000		6	4,569
22,000 FL		23	1,897
63,000 FL		24	4,569
Sodium Vapor			
4,000		70	248
5,800		71	349
9,600		72	490
27,500		74	1,284
50,000		75	1,968
27,500	FL	77	1,284
50,000	FL	78	1,968
9,600	Post Top	79	490
27,500	(24 hr)	84	2,568

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.259¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation & Load Management Adjustment per kWh	0.230¢

	Narragansett Zone	Blackstone Zone	Newport Zone
Streetlight Credit per kWh	0.000¢	4.420¢	2.918¢

Standard Offer	per Standard Offer Service tariff (Optional)
Last Resort	per Last Resort Service tariff (Optional)

Tax Note:The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.
Other Rate Clauses apply as usual.

R.I.P.U.C. No. 1181

Luminaire Type/Lumens	Code	Annual kWh
Incandescent		
1,000	10	440
1,500	11	845
Mercury Vapor		
8,000 Post Top	02	908
4,000	03	561
8,000	04	908
15,000	17, 18	1,874
22,000	05	1,897
63,000	06	4,569
Sodium Vapor		
4,000	70, 710, 711, 750, 755, 756	248
5,800	71	349
9,600	72	490
27,500	74	1,284
50,000	75	1,968
27,500 (24 hr)	84	2,568
50,000 FL	78	1,968
9,600 Post Top	79	490

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.259¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation & Load Management Adj. per kWh	0.230¢

	Narragansett Zone	Blackstone Zone	Newport Zone
Streetlight Credit per kWh	0.000¢	4.420¢	2.918¢

Standard Offer Service	per Standard Offer Service tariff (Optional)
Last Resort Service	per Last Resort Service tariff (Optional)

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

Monthly Charge As Adjusted

Rates for Retail Delivery Service
Residential:

Customer Charge per month	$2.75
Distribution Charge per kWh	2.699¢ (Eff. January 1, 2006) 2.924¢ (Eff. January 1, 2007) 3.150¢ (Eff. January 1, 2008) 3.376¢ (Eff. January 1, 2009)
Minimum Charge per month	$2.75

Commercial:

Customer Charge per month	$6.00
Distribution Charge per kWh	2.797¢ (Eff. January 1, 2006) 3.072¢ (Eff. January 1, 2007) 3.347¢ (Eff. January 1, 2008) 3.624¢ (Eff. January 1, 2009)
Minimum Charge per month	$6.00

All Classes:

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.361¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

Effective
January 1, 2006

Electric Propulsion Rate (X-01)
High Voltage Delivery Service

R.I.P.U.C. No. 1183

Monthly Charge As Adjusted

Rates for High Voltage Delivery Service

Customer Charge per month	$10,000.00
Transmission Demand Charge per kW	$1.34
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Energy Charge per kWh	0.312¢
Conservation and Load Management Adjustment per kWh	0.230¢

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

Effective
January 1, 2006

Station Power Delivery and Reliability Service Rate (M-1)
Retail Delivery Service

R.I.P.U.C. No. 1184

Rates for Station Power Delivery and Reliability Service

Eligible Customers must select one of the two rate Options A or B below:

Monthly Charges

OPTION A

Distribution Delivery Service Charge	$3,406.18 per month
Non-Bypassable Transition Charge	Higher of: 0.575¢ per kWh or $3,500
Conservation and Load Management Charge	Higher of 0.230¢ per kWh or $800

OPTION B

Distribution Delivery Service Charge	$3,406.18 per month
Non-Bypassable Transition Charge	0.575¢ per kWh
Conservation and Load Management Charge	0.230¢ per kWh

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

THE NARRAGANSETT ELECTRIC COMPANY
Basic Residential Rate (A-16)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1170

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$2.75
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.436¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	3.379¢ (Eff. Jan 1, 2006) 3.378¢ (Eff. Jan 1, 2007) 3.377¢ (Eff. Jan 1, 2008) 3.376¢ (Eff. Jan 1, 2009)
Minimum Charge per month	$2.75
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: 845

Deleted: 239

Deleted: 3.380¢ (Eff. October 28, 2004)

Deleted: Customer Credit per kWh 0.329¢ (Eff. November 1, 2004)¶
¶
Customer Credit per kWh (former Rate A-32) 0.820¢¶
¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Low Income Rate (A-60)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1171

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.338¢
Transmission Adjustment Factor per kWh	0.371¢

Deleted: .845

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Distribution Charges per kWh

December through March	
First 450 kWhs	1.688¢
Next 750 kWhs	3.055¢
kWhs in excess of 1200 kWhs	2.548¢
April through November	
First 450 kWhs	1.688¢
kWhs in excess of 450 kWhs	3.055¢

Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: Customer Credit per kWh 0.329¢ (Eff. November 1, 2004)¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

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THE NARRAGANSETT ELECTRIC COMPANY
C&I Back-Up Service Rate (B-32)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1172

Monthly Charge As Adjusted

	Rates for Back-Up Service	Rates for Supplemental Service
Rates for Retail Delivery Service		
Customer Charge per month	$236.43	n/a
Transmission Demand Charge per kW	n/a	$1.27
Distribution Demand Charge per kW	$5.15	$2.02 (Eff. January 1, 2006)
	$5.13	$2.01 (Eff. January 1, 2007)
	$5.12	$2.00 (Eff. January 1, 2008)
	$5.11	$1.99 (Eff. January 1, 2009)
Distribution Demand Charge per kW (Applicable to former Auxiliary Service Customers)		
	$2.07	$2.02 (Eff. January 1, 2006)
	$3.09	$2.01 (Eff. January 1, 2007)
	$4.11	$2.00 (Eff. January 1, 2008)
	$5.11	$1.99 (Eff. January 1, 2009)
Transmission Adjustment Factor per kWh	n/a	0.371¢
Distribution Energy Charge per kWh	n/a	0.889¢
Non-bypassable Transition Charge per kWh	n/a	0.575¢
C&LM Adjustment per kWh	n/a	0.230¢
Rates for Standard Offer Service or Last Resort Service (Optional)		
Standard Offer per kWh	n/a	per Standard Offer Service tariff
Last Resort per kWh	n/a	per Last Resort Service tariff

Deleted: $5.33 $2.10 (Eff. October 28, 2004)

Deleted: $1.05 $2.10 (Eff. October 28, 2004)

Deleted: .239

Deleted: .845

Deleted: Customer Credit per kWh n/a 0.231¢ (Eff. November 1, 2004)¶
¶

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
3,000 kW Back-Up Service Rate (B-62)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1173

Monthly Charge As Adjusted

Rates for Retail Delivery Service	Rates for Back-Up Service	Rates for Supplemental Service
Customer Charge per month	$17,118.72	n/a
Distribution Demand Charge per kW	$2.26	$2.26 (Eff. January 1, 2006)
	$2.25	$2.25 (Eff. January 1, 2007)
	$2.24	$2.24 (Eff. January 1, 2008)
	$2.22	$2.22 (Eff. January 1, 2009)
Distribution Demand Charge per kW (Applicable to former Auxiliary Service Customers)		
	$0.89	$2.26 (Eff. January 1, 2006)
	$1.33	$2.25 (Eff. January 1, 2007)
	$1.77	$2.24 (Eff. January 1, 2008)
	$2.22	$2.22 (Eff. January 1, 2009)
Transmission Demand Charge per kW	n/a	$1.39
Transmission Adjustment Factor per kWh	n/a	0.371¢
Non-bypassable Transition Charge per kWh	n/a	0.575¢
C&LM Adjustment per kWh	n/a	0.230¢

Deleted: $2.34 $2.34 (Eff. October 28, 2004)

Deleted: $0.45 $2.34 (Eff. October 28, 2004)

Deleted: .239

Deleted: .845

Deleted: Customer Credit per kWh n/a 0.212¢ (Eff. November 1, 2004)¶

Rates for Standard Offer Service or Last Resort Service (Optional)		
Standard Offer per kWh	n/a	per Standard Offer Service tariff
Last Resort per kWh	n/a	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

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THE NARRAGANSETT ELECTRIC COMPANY
Small C&I Rate (C-06)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1174

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$6.00	
Unmetered Charge per month	$1.83	
Non-Bypassable Transition Charge per kWh	0.575¢	**Deleted:** .845
Transmission Charge per kWh	0.536¢	
Transmission Adjustment Factor per kWh	0.371¢	**Deleted:** .239
Distribution Charge per kWh	3.652¢ (Eff. January 1, 2006) 3.643¢ (Eff. January 1, 2007) 3.634¢ (Eff. January 1, 2008) 3.624¢ (Eff. January 1, 2009)	**Deleted:** 3.662¢ (Eff. October 28, 2004)
Conservation and Load Management Adjustment per kWh	0.230¢	

Deleted: Customer Credit per kWh 0.365¢ (Eff. November 1, 2004)¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Residential Storage Heating Rate (E-30)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1175

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$2.75
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.261¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	2.300¢ (Eff. January 1, 2006) 2.658¢ (Eff. January 1, 2007) 3.017¢ (Eff. January 1, 2008) 3.376¢ (Eff. January 1, 2009)
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: .845

Deleted: .239

Deleted: 1.941¢ (Eff. October 28, 2004)

Deleted: Customer Credit per kWh 0.329¢ (Eff. November 1, 2004)¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Storage Cooling Rate (E-40)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No 1190

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$75.15
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.141¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	
Peak/Shoulder	2.536¢
Off Peak	0.949¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: .845

Deleted: .239

Deleted: Customer Credit per kWh 0.231¢ (Eff. November 1, 2004)¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
General C&I Rate (G-02)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1176

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$103.41
Transmission Charge per kW in excess of 10 kW	$1.40
Distribution Charge per kW in excess of 10 kW	$3.22
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	0.777¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: $3.23 (Eff. October 28, 2004)

Deleted: (Eff. January 1, 2006)

Deleted: .845

Deleted: .239

Deleted: Customer Credit per kWh 0.277¢ (Eff. November 1, 2004)¶
¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes. However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
200 kW Demand Rate (G-32)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1177

Monthly Charge As Adjusted

Rates for Retail Delivery Service

Customer Charge per month	$236.43
Transmission Charge per kW	$1.27
Distribution Charge per kW	$2.02 (Eff. January 1, 2006) $2.01 (Eff. January 1, 2007) $2.00 (Eff. January 1, 2008) $1.99 (Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	0.889¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: $2.10 (Eff. October 28, 2004)

Deleted: .845

Deleted: .239

Deleted: Customer Credit per kWh 0.231¢ (Eff. November 1, 2004)¶
¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

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THE NARRAGANSETT ELECTRIC COMPANY
3000 kW Demand Rate (G-62)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1178

Monthly Charge As Adjusted

Rates for Retail Delivery Services

Customer Charge per month	$17,118.72
Transmission Charge per kW	$1.39
Distribution Charge per kW	$2.26 (Eff. January 1, 2006) $2.25 (Eff. January 1, 2007) $2.24 (Eff. January 1, 2008) $2.22 (Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: $2.34 (Eff. October 28, 2004)

Deleted: .845

Deleted: .239

Deleted: Customer Credit per kWh 0.212¢ (Eff. November 1, 2004)¶
¶
¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Limited Traffic Signal Service (R-02)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1179

Monthly Charge as Adjusted

Rates for Retail Delivery Service

Unmetered Charge per month	$0.72 (Eff. January 1, 2006) $1.08 (Eff. January 1, 2007) $1.44 (Eff. January 1, 2008) $1.83 (Eff. January 1, 2009)
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.259¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Charge per kWh	1.969¢ (Eff. January 1, 2006) 2.520¢ (Eff. January 1, 2007) 3.071¢ (Eff. January 1, 2008) 3.624¢ (Eff. January 1, 2009)
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: $0.36 (Eff. October 28, 2004)

Deleted: .845

Deleted: .239

Deleted: 1.418¢ (Eff. October 28, 2004)

Deleted: Customer Credit per kWh 0.365¢ (Eff. November 1, 2004)¶
¶

Rates for Standard Offer Service or Last Resort (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

Effective
January 1, 2006

Deleted: January 1, 2005

Limited Service - Private Lighting (S-10)
Retail Delivery Service

R.I.P.U.C. No. 1180

Luminaire Type/Lumens		Code	Annual kWh
Incandescent			
1,000		10	440
Mercury Vapor			
8,000	Post Top	2	908
4,000		3	561
8,000		4	908
22,000		5	1,897
63,000		6	4,569
22,000 FL		23	1,897
63,000 FL		24	4,569
Sodium Vapor			
4,000		70	248
5,800		71	349
9,600		72	490
27,500		74	1,284
50,000		75	1,968
27,500	FL	77	1,284
50,000	FL	78	1,968
9,600	Post Top	79	490
27,500	(24 hr)	84	2,568

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.259¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation & Load Management Adjustment per kWh	0.230¢

Deleted: 845

Deleted: 239

	Narragansett Zone	Blackstone Zone	Newport Zone
Streetlight Credit per kWh	0.000¢	4.420¢	2.918¢

Deleted: Customer Credit per kWh (Eff. November 1, 2004)
0.811¢ 0.811¢ 0.811¢¶

Standard Offer	per Standard Offer Service tariff (Optional)
Last Resort	per Last Resort Service tariff (Optional)

Tax Note:The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.
Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

General Streetlighting Service (S-14)

Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1181

Luminaire Type/Lumens	Code	Annual kWh
Incandescent		
1,000	10	440
1,500	11	845
Mercury Vapor		
8,000 Post Top	02	908
4,000	03	561
8,000	04	908
15,000	17, 18	1,874
22,000	05	1,897
63,000	06	4,569
Sodium Vapor		
4,000	70, 710, 711, 750, 755, 756	248
5,800	71	349
9,600	72	490
27,500	74	1,284
50,000	75	1,968
27,500 (24 hr)	84	2,568
50,000 FL	78	1,968
9,600 Post Top	79	490

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.259¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation & Load Management Adj. per kWh	0.230¢

Deleted: 845

Deleted: 239

	Narragansett Zone	Blackstone Zone	Newport Zone
Streetlight Credit per kWh	0.000¢	4.420¢	2.918¢

Deleted: Customer Credit per kWh (Eff. November 1, 2004) 0.811¢ 0.811¢ 0.811¢¶
¶

Standard Offer Service	per Standard Offer Service tariff (Optional)
Last Resort Service	per Last Resort Service tariff (Optional)

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY
Limited Service All-Electric Living (T-06)
Retail Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1182

Monthly Charge As Adjusted

Rates for Retail Delivery Service
Residential:

Customer Charge per month	$2.75
Distribution Charge per kWh	2.699¢ (Eff. January 1, 2006) 2.924¢ (Eff. January 1, 2007) 3.150¢ (Eff. January 1, 2008) 3.376¢ (Eff. January 1, 2009)
Minimum Charge per month	$2.75

Deleted: 2.473¢ (Eff. October 28, 2004)

Deleted: Customer Credit per kWh 0.329¢ (Eff. November 1, 2004)¶

Commercial:

Customer Charge per month	$6.00
Distribution Charge per kWh	2.797¢ (Eff. January 1, 2006) 3.072¢ (Eff. January 1, 2007) 3.347¢ (Eff. January 1, 2008) 3.624¢ (Eff. January 1, 2009)
Minimum Charge per month	$6.00

Deleted: 2.522¢ (Eff. October 28, 2004)

Deleted: Customer Credit per kWh 0.365¢ (Eff. November 1, 2004)¶

All Classes:

Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Charge per kWh	0.361¢
Transmission Adjustment Factor per kWh	0.371¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: .845

Deleted: .239

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

Electric Propulsion Rate (X-01)
High Voltage Delivery Service

Effective
January 1, 2006

Deleted: January 1, 2005

R.I.P.U.C. No. 1183

Monthly Charge As Adjusted

Rates for High Voltage Delivery Service

Customer Charge per month	$10,000.00
Transmission Demand Charge per kW	$1.34
Non-Bypassable Transition Charge per kWh	0.575¢
Transmission Adjustment Factor per kWh	0.371¢
Distribution Energy Charge per kWh	0.312¢
Conservation and Load Management Adjustment per kWh	0.230¢

Deleted: .845

Deleted: .239

Deleted: Customer Credit per kWh 0.190¢ (Eff. November 1, 2004)¶
¶

Rates for Standard Offer Service or Last Resort Service (Optional)

Standard Offer per kWh	per Standard Offer Service tariff
Last Resort per kWh	per Last Resort Service tariff

Tax Note: The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

Effective
January 1, 2006

Deleted: January 1, 2005

Station Power Delivery and Reliability Service Rate (M-1)
Retail Delivery Service

R.I.P.U.C. No. 1184

Rates for Station Power Delivery and Reliability Service

Eligible Customers must select one of the two rate Options A or B below:

Monthly Charges

OPTION A

Distribution Delivery Service Charge	$3,406.18 per month
Non-Bypassable Transition Charge	Higher of: 0.575¢ per kWh or $3,500
Conservation and Load Management Charge	Higher of 0.230¢ per kWh or $800

Deleted: .845

Deleted: Customer Credit per kWh 0.231¢ (Eff. November 1, 2004)¶
¶

OPTION B

Distribution Delivery Service Charge	$3,406.18 per month
Non-Bypassable Transition Charge	0.575¢ per kWh
Conservation and Load Management Charge	0.230¢ per kWh

Deleted: .845

Deleted: Customer Credit per kWh 0.231¢ (Eff. November 1, 2004)¶
¶

Tax Note: **The rates listed above do not reflect gross earnings tax or sales taxes (when applicable). However, such taxes, when applicable, will appear on bills sent to customers.**

Exhibit JAL-8

Typical Bill Analysis for Residential Customer

Typical Bill Analysis for Residential Customer
Rate A-16 Customer Using 500 kWhs per month

Present Rates @ 10/31/05:

Customer Charge		$2.75
Transmission Energy Charge (1)	kWh x	$0.00675
Distribution Energy Charge	kWh x	$0.03380
Transition Energy Charge	kWh x	$0.00845
Conservation	kWh x	$0.00230
Customer Credit	kWh x	($0.00329)
Standard Offer Charge	kWh x	$0.08200
Gross Earnings Tax		4.0%

(1) Inlcudes adj factor of $0.00239 per kWh

Monthly Bill Impacts of Rate Changes Proposed in Filing:

		Proposed Charges											
		Customer Charge	Distribution kWh Charge	Transmission kWh Charge (2)	Transition Charge	Transition Reconciliation Credit	Conservation Charge	Customer Credit	Standard Offer	Present Bill	Proposed Bill	Difference	Percentage Difference
1.		$2.75	$0.03380	$0.00807	$0.00680	($0.00105)	$0.00230	($0.00329)	$0.08200	$70.58	69.86	($0.72)	-1.0%
2.		$2.75	$0.03380	$0.00807	$0.00680	$0.00000	$0.00230	($0.00329)	$0.08200	$70.58	70.41	($0.17)	-0.2%
3.	(3)	$2.75	$0.03379	$0.00807	$0.00680	($0.00105)	$0.00230	$0.00000	$0.08200	$70.58	71.57	$0.99	1.4%
4.	(3)	$2.75	$0.03379	$0.00807	$0.00680	$0.00000	$0.00230	$0.00000	$0.08200	$70.58	72.11	$1.53	2.2%

(2) Transmission kWh charge includes proposed adjustment factor of $0.00371 per kWh

(3) Rate changes already approved for January 1, 2006 include the elimination of the Customer Credit effective December 31, 2005 and changes to the distribution kWh charge approved in Docket 3617.

Exhibit JAL-9

Typical Bill Analysis for All Rate Classes

File: S:\RADATA1\2005 neco\Year End Filing\[TYPBILLS.RECON.XLS]Input Section

Date: 14-Nov-05
Time: 06:12 PM

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-16 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
120	$19.12	$10.25	$8.87	$19.35	$10.25	$9.10	$0.23	1.2%	9.0%
240	$35.37	$20.50	$14.87	$35.84	$20.50	$15.34	$0.47	1.3%	15.7%
500	$70.58	$42.71	$27.87	$71.57	$42.71	$28.86	$0.99	1.4%	38.2%
700	$97.66	$59.79	$37.87	$99.05	$59.79	$39.26	$1.39	1.4%	20.2%
950	$131.52	$81.15	$50.37	$133.40	$81.15	$52.25	$1.88	1.4%	14.6%
1,000	$138.30	$85.42	$52.88	$140.27	$85.42	$54.85	$1.97	1.4%	2.3%

Present Rates: A-16

Customer Charge		$2.75
Transmission Energy Charge (1)	kWh x	$0.00675
Distribution Energy Charge	kWh x	$0.03380
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit		-$0.00329
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: A-16

Customer Charge		$2.75
Transmission Energy Charge (2)	kWh x	$0.00807
Distribution Energy Charge	kWh x	$0.03379
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

File: S:\RADATA1\2005 neco\Year End Filing\[TYPBILLS.RECON.XLS]Input Section

Date: 14-Nov-05
Time: 06:12 PM

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-16 (former A-32) Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
500	$68.02	$42.71	$25.31	$71.57	$42.71	$28.86	$3.55	5.2%	5.3%
1,000	$133.18	$85.42	$47.76	$140.27	$85.42	$54.85	$7.09	5.3%	12.7%
2,500	$328.64	$213.54	$115.10	$346.38	$213.54	$132.84	$17.74	5.4%	39.1%
5,000	$654.42	$427.08	$227.34	$689.89	$427.08	$262.81	$35.47	5.4%	35.1%
7,500	$980.21	$640.63	$339.58	$1,033.42	$640.63	$392.79	$53.21	5.4%	7.8%

Present Rates:	A-16 (former A-32)		Proposed Rates:	A-16	
Customer Charge		$2.75	Customer Charge		$2.75
Transmission Energy Charge (1)	kWh x	$0.00675	Transmission Energy Charge (2)	kWh x	$0.00807
Distribution Energy Charge	kWh x	$0.03380	Distribution Energy Charge	kWh x	$0.03379
Transition Energy Charge	kWh x	$0.00845	Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230	C&LM Adjustment	kWh x	$0.00230
Customer Credit		-$0.00820			
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge		$0.08200	Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

File: S:\RADATA1\2005 neco\Year End Filing\[TYPBILLS.RECON.XLS]Input Section

Date: 14-Nov-05
Time: 06:12 PM

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers - Winter (December through March)
Without Control Credit for Water Heater

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
100	$11.68	$8.54	$3.14	$11.88	$8.54	$3.34	$0.20	1.7%
200	$23.35	$17.08	$6.27	$23.75	$17.08	$6.67	$0.40	1.7%
300	$35.04	$25.63	$9.41	$35.64	$25.63	$10.01	$0.60	1.7%
500	$59.10	$42.71	$16.39	$60.10	$42.71	$17.39	$1.00	1.7%
750	$91.86	$64.06	$27.80	$93.35	$64.06	$29.29	$1.49	1.6%
1250	$157.10	$106.77	$50.33	$159.59	$106.77	$52.82	$2.49	1.6%

Present Rates:	A-60		Proposed Rates:	A-60	
Customer Charge		$0.00	Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.00577	Transmission Energy Charge (2)	kWh x	$0.00709
Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688	Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688
Second Block Energy Charge (next 750 kWl	kWh x	$0.03055	Second Block Energy Charge (next 750 kWl	0	$0.03055
Tail Block Energy Charge	kWh x	$0.02548	Tail Block Energy Charge	0	$0.02548
Transition Energy Charge		$0.00845	Transition Energy Charge	0	$0.00575
C&LM Adjustment	kWh x	$0.00230	C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00329			
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200	Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers - Winter (December through March)
With Control Credit for Water Heater

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Difference Amount	Difference % of Total	
100	$11.13	$8.54	$2.59	$11.46	$8.54	$2.92	$0.33	3.0%	
200	$22.25	$17.08	$5.17	$22.93	$17.08	$5.85	$0.68	3.1%	
300	$33.39	$25.63	$7.76	$34.40	$25.63	$8.77	$1.01	3.0%	
500	$56.35	$42.71	$13.64	$58.04	$42.71	$15.33	$1.69	3.0%	
750	$87.73	$64.06	$23.67	$90.25	$64.06	$26.19	$2.52	2.9%	
1250	$152.98	$106.77	$46.21	$156.50	$106.77	$49.73	$3.52	2.3%	

Present Rates:	A-60		
Customer Charge			$0.00
Transmission Energy Charge (1)	kWh x		$0.00577
Initial Block Energy Charge (1st 450 kWh)	kWh x		$0.01688
Second Block Energy Charge (next 750 kWl	kWh x		$0.03055
Tail Block Energy Charge	kWh x		$0.02548
Transition Energy Charge		0	$0.00845
C&LM Adjustment	kWh x		$0.00230
Customer Credit	kWh x		-$0.00329
Water Heating Credit	kWh x		-$0.00528
Gross Earnings Tax			4.00%
Standard Offer Charge	kWh x		$0.08200

Proposed Rates:	A-60		
Customer Charge			$0.00
Transmission Energy Charge (2)	kWh x		$0.00709
Initial Block Energy Charge (1st 450 kWh)	kWh x		$0.01688
Second Block Energy Charge (next 750 kWl		0	$0.03055
Tail Block Energy Charge		0	$0.02548
Transition Energy Charge		0	$0.00575
C&LM Adjustment	kWh x		$0.00230
Water Heating Credit	kWh x		-$0.00396
Gross Earnings Tax			4.00%
Standard Offer Charge			$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers - Non-Winter (April through November)
Without Control Credit for Water Heater

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Difference Amount	Difference % of Total
100	$11.68	$8.54	$3.14	$11.88	$8.54	$3.34	$0.20	1.7%
200	$23.35	$17.08	$6.27	$23.75	$17.08	$6.67	$0.40	1.7%
300	$35.04	$25.63	$9.41	$35.64	$25.63	$10.01	$0.60	1.7%
500	$59.10	$42.71	$16.39	$60.10	$42.71	$17.39	$1.00	1.7%
750	$91.86	$64.06	$27.80	$93.35	$64.06	$29.29	$1.49	1.6%
1250	$157.37	$106.77	$50.60	$159.85	$106.77	$53.08	$2.48	1.6%

<u>Present Rates:</u> A-60

Customer Charge		$0.00
Transmission Energy Charge (1)	kWh x	$0.00577
Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688
Tail Block Energy Charge	kWh x	$0.03055
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00329
Gross Earnings Tax		4.0%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> A-60

Customer Charge		$0.00
Transmission Energy Charge (2)	kWh x	$0.00709
Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688
Tail Block Energy Charge	0	$0.03055
Transition Energy Charge	0	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.0%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers - Non-Winter (April through November)
With Control Credit for Water Heater

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Difference Amount	Difference % of Total
100	$11.13	$8.54	$2.59	$11.26	$8.54	$2.72	$0.13	1.2%
200	$22.25	$17.08	$5.17	$22.53	$17.08	$5.45	$0.28	1.3%
300	$33.39	$25.63	$7.76	$33.80	$25.63	$8.17	$0.41	1.2%
500	$56.35	$42.71	$13.64	$57.04	$42.71	$14.33	$0.69	1.2%
750	$87.73	$64.06	$23.67	$88.76	$64.06	$24.70	$1.03	1.2%
1250	$153.24	$106.77	$46.47	$154.27	$106.77	$47.50	$1.03	0.7%

<u>Present Rates:</u> A-60

Customer Charge		$0.01
Transmission Energy Charge (1)	kWh x	$0.00577
Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688
Tail Block Energy Charge	kWh x	$0.03055
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00329
Water Heating Credit	kWh x	-$0.00528
Gross Earnings Tax		4.0%
Standard Offer Charge		$0.08200

<u>Proposed Rates:</u> A-60

Customer Charge		$0.01
Transmission Energy Charge (2)	kWh x	$0.00709
Initial Block Energy Charge (1st 450 kWh)	kWh x	$0.01688
Tail Block Energy Charge	0	$0.03055
Transition Energy Charge	0	$0.00575
C&LM Adjustment	kWh x	$0.00230
Water Heating Credit	kWh x	-$0.00396
Gross Earnings Tax		4.0%
Standard Offer Charge		$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on C-06 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
250	$41.00	$21.35	$19.65	$41.57	$21.35	$20.22	$0.57	1.4%	35.2%
500	$75.77	$42.71	$33.06	$76.90	$42.71	$34.19	$1.13	1.5%	17.0%
1,000	$145.28	$85.42	$59.86	$147.55	$85.42	$62.13	$2.27	1.6%	19.0%
1,500	$214.80	$128.13	$86.67	$218.19	$128.13	$90.06	$3.39	1.6%	9.8%
2,000	$284.31	$170.83	$113.48	$288.83	$170.83	$118.00	$4.52	1.6%	19.1%

Present Rates: C-06

Customer Charge		$6.00
Transmission Energy Charge (1)	kWh x	$0.00775
Distribution Energy Charge	kWh x	$0.03662
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00365
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: C-06

Customer Charge		$6.00
Transmission Energy Charge (2)	kWh x	$0.00907
Distribution Energy Charge	kWh x	$0.03652
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on R-02 (Phase-out to C-06) Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
250	$28.56	$21.35	$7.21	$30.96	$21.35	$9.61	$2.40	8.4%	15.6%
500	$56.76	$42.71	$14.05	$61.19	$42.71	$18.48	$4.43	7.8%	23.1%
1,000	$113.15	$85.42	$27.73	$121.63	$85.42	$36.21	$8.48	7.5%	49.2%
1,500	$169.54	$128.13	$41.41	$182.07	$128.13	$53.94	$12.53	7.4%	10.3%
2,000	$225.91	$170.83	$55.08	$242.50	$170.83	$71.67	$16.59	7.3%	1.8%

<u>Present Rates:</u> R-02 (Phase-out to C-06)

Unmetered Charge		$0.36
Transmission Energy Charge (1)	kWh x	$0.00498
Distribution Energy Charge	kWh x	$0.01418
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00365
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> R-02 (Phase-out to C-06)

Unmetered Charge		$0.72
Transmission Energy Charge (2)	kWh x	$0.00630
Distribution Energy Charge	kWh x	$0.01969
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on E-30 (Phase-out to A-16) Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
1,000	$121.48	$85.42	$36.06	$127.21	$85.42	$41.79	$5.73	4.7%	15.4%
2,500	$299.40	$213.54	$85.86	$313.72	$213.54	$100.18	$14.32	4.8%	15.4%
5,000	$595.93	$427.08	$168.85	$624.58	$427.08	$197.50	$28.65	4.8%	38.5%
10,000	$1,189.01	$854.17	$334.84	$1,246.31	$854.17	$392.14	$57.30	4.8%	0.0%
25,000	$2,968.23	$2,135.42	$832.81	$3,111.46	$2,135.42	$976.04	$143.23	4.8%	7.7%
50,000	$5,933.59	$4,270.83	$1,662.76	$6,220.05	$4,270.83	$1,949.22	$286.46	4.8%	23.1%

<u>Present Rates:</u> E-30 (Phase-out to A-16)

Customer Charge		$2.75
Transmission Energy Charge (1)	kWh x	$0.00500
Distribution Energy Charge	kWh x	$0.01941
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00329
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> E-30 (Phase-out to A-16)

Customer Charge		$2.75
Transmission Energy Charge (2)	kWh x	$0.00632
Distribution Energy Charge	kWh x	$0.02300
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$573.20	$341.67	$231.53	$578.89	$341.67	$237.22	$5.69	1.0%
50	10,000	$1,343.76	$854.17	$489.59	$1,357.83	$854.17	$503.66	$14.07	1.0%
100	20,000	$2,628.03	$1,708.33	$919.70	$2,656.05	$1,708.33	$947.72	$28.02	1.1%
150	30,000	$3,912.30	$2,562.50	$1,349.80	$3,954.28	$2,562.50	$1,391.78	$41.98	1.1%

Present Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge-xcs 10 kW	kW x	$3.23
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00277
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$781.82	$512.50	$269.32	$790.41	$512.50	$277.91	$8.59	1.1%
50	15,000	$1,865.32	$1,281.25	$584.07	$1,886.63	$1,281.25	$605.38	$21.31	1.1%
100	30,000	$3,671.16	$2,562.50	$1,108.66	$3,713.66	$2,562.50	$1,151.16	$42.50	1.2%
150	45,000	$5,476.99	$3,843.75	$1,633.24	$5,540.69	$3,843.75	$1,696.94	$63.70	1.2%

<u>Present Rates:</u> G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge-xcs 10 kW	kW x	$3.23
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00277
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$990.44	$683.33	$307.11	$1,001.92	$683.33	$318.59	$11.48	1.2%
50	20,000	$2,386.88	$1,708.33	$678.55	$2,415.42	$1,708.33	$707.09	$28.54	1.2%
100	40,000	$4,714.28	$3,416.67	$1,297.61	$4,771.26	$3,416.67	$1,354.59	$56.98	1.2%
150	60,000	$7,041.68	$5,125.00	$1,916.68	$7,127.09	$5,125.00	$2,002.09	$85.41	1.2%

Present Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge-xcs 10 kW	kW x	$3.23
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00277
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,199.08	$854.17	$344.91	$1,213.45	$854.17	$359.28	$14.37	1.2%
50	25,000	$2,908.45	$2,135.42	$773.03	$2,944.23	$2,135.42	$808.81	$35.78	1.2%
100	50,000	$5,757.40	$4,270.83	$1,486.57	$5,828.86	$4,270.83	$1,558.03	$71.46	1.2%
150	75,000	$8,606.36	$6,406.25	$2,200.11	$8,713.50	$6,406.25	$2,307.25	$107.14	1.2%

Present Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge-xcs 10 kW	kW x	$3.23
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00277
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,407.70	$1,025.00	$382.70	$1,424.97	$1,025.00	$399.97	$17.27	1.2%
50	30,000	$3,430.01	$2,562.50	$867.51	$3,473.03	$2,562.50	$910.53	$43.02	1.3%
100	60,000	$6,800.53	$5,125.00	$1,675.53	$6,886.47	$5,125.00	$1,761.47	$85.94	1.3%
150	90,000	$10,171.05	$7,687.50	$2,483.55	$10,299.91	$7,687.50	$2,612.41	$128.86	1.3%

Present Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge-xcs 10 kW	kW x	$3.23
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit	kWh x	-$0.00277
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-02

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,186.70	$3,416.67	$1,770.03	$5,208.78	$3,416.67	$1,792.11	$22.08	0.4%
750	150,000	$18,772.84	$12,812.50	$5,960.34	$18,855.66	$12,812.50	$6,043.16	$82.82	0.4%
1,000	200,000	$24,948.36	$17,083.33	$7,865.03	$25,058.78	$17,083.33	$7,975.45	$110.42	0.4%
1,500	300,000	$37,299.41	$25,625.00	$11,674.41	$37,465.03	$25,625.00	$11,840.03	$165.62	0.4%
2,500	500,000	$62,001.49	$42,708.33	$19,293.16	$62,277.53	$42,708.33	$19,569.20	$276.04	0.4%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.10
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00231
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.02
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$7,305.86	$5,125.00	$2,180.86	$7,347.32	$5,125.00	$2,222.32	$41.46	0.6%
750	225,000	$26,719.72	$19,218.75	$7,500.97	$26,875.19	$19,218.75	$7,656.44	$155.47	0.6%
1,000	300,000	$35,544.20	$25,625.00	$9,919.20	$35,751.49	$25,625.00	$10,126.49	$207.29	0.6%
1,500	450,000	$53,193.16	$38,437.50	$14,755.66	$53,504.09	$38,437.50	$15,066.59	$310.93	0.6%
2,500	750,000	$88,491.07	$64,062.50	$24,428.57	$89,009.30	$64,062.50	$24,946.80	$518.23	0.6%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.10
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00231
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.02
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$9,425.03	$6,833.33	$2,591.70	$9,485.86	$6,833.33	$2,652.53	$60.83	0.6%
750	300,000	$34,666.59	$25,625.00	$9,041.59	$34,894.72	$25,625.00	$9,269.72	$228.13	0.7%
1,000	400,000	$46,140.03	$34,166.67	$11,973.36	$46,444.20	$34,166.67	$12,277.53	$304.17	0.7%
1,500	600,000	$69,086.91	$51,250.00	$17,836.91	$69,543.16	$51,250.00	$18,293.16	$456.25	0.7%
2,500	1,000,000	$114,980.66	$85,416.67	$29,563.99	$115,741.08	$85,416.67	$30,324.41	$760.42	0.7%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.10
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00231
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.02
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$11,544.20	$8,541.67	$3,002.53	$11,624.41	$8,541.67	$3,082.74	$80.21	0.7%
750	375,000	$42,613.47	$32,031.25	$10,582.22	$42,914.25	$32,031.25	$10,883.00	$300.78	0.7%
1,000	500,000	$56,735.86	$42,708.33	$14,027.53	$57,136.90	$42,708.33	$14,428.57	$401.04	0.7%
1,500	750,000	$84,980.66	$64,062.50	$20,918.16	$85,582.22	$64,062.50	$21,519.72	$601.56	0.7%
2,500	1,250,000	$141,470.24	$106,770.83	$34,699.41	$142,472.84	$106,770.83	$35,702.01	$1,002.60	0.7%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.10
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00231
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.02
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$13,663.36	$10,250.00	$3,413.36	$13,762.95	$10,250.00	$3,512.95	$99.59	0.7%
750	450,000	$50,560.34	$38,437.50	$12,122.84	$50,933.78	$38,437.50	$12,496.28	$373.44	0.7%
1,000	600,000	$67,331.70	$51,250.00	$16,081.70	$67,829.61	$51,250.00	$16,579.61	$497.91	0.7%
1,500	900,000	$100,874.41	$76,875.00	$23,999.41	$101,621.28	$76,875.00	$24,746.28	$746.87	0.7%
2,500	1,500,000	$167,959.82	$128,125.00	$39,834.82	$169,204.61	$128,125.00	$41,079.61	$1,244.79	0.7%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.10
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00231
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.02
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 200

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	600,000	$87,625.75	$51,250.00	$36,375.75	$87,838.25	$51,250.00	$36,588.25	$212.50	0.2%
5,000	1,000,000	$134,154.92	$85,416.67	$48,738.25	$134,509.09	$85,416.67	$49,092.42	$354.17	0.3%
7,500	1,500,000	$192,316.38	$128,125.00	$64,191.38	$192,847.63	$128,125.00	$64,722.63	$531.25	0.3%
10,000	2,000,000	$250,477.83	$170,833.33	$79,644.50	$251,186.16	$170,833.33	$80,352.83	$708.33	0.3%
20,000	4,000,000	$483,123.67	$341,666.67	$141,457.00	$484,540.34	$341,666.67	$142,873.67	$1,416.67	0.3%

Present Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.34
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00212
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.26
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 300

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	% of Total
3,000	900,000	$116,694.50	$76,875.00	$39,819.50	$117,138.25	$76,875.00	$40,263.25	$443.75	0.4%
5,000	1,500,000	$182,602.83	$128,125.00	$54,477.83	$183,342.42	$128,125.00	$55,217.42	$739.59	0.4%
7,500	2,250,000	$264,988.25	$192,187.50	$72,800.75	$266,097.63	$192,187.50	$73,910.13	$1,109.38	0.4%
10,000	3,000,000	$347,373.67	$256,250.00	$91,123.67	$348,852.83	$256,250.00	$92,602.83	$1,479.16	0.4%
20,000	6,000,000	$676,915.33	$512,500.00	$164,415.33	$679,873.67	$512,500.00	$167,373.67	$2,958.34	0.4%

Present Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.34
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00212
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.26
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,200,000	$145,763.25	$102,500.00	$43,263.25	$146,438.25	$102,500.00	$43,938.25	$675.00	0.5%
5,000	2,000,000	$231,050.75	$170,833.33	$60,217.42	$232,175.75	$170,833.33	$61,342.42	$1,125.00	0.5%
7,500	3,000,000	$337,660.13	$256,250.00	$81,410.13	$339,347.63	$256,250.00	$83,097.63	$1,687.50	0.5%
10,000	4,000,000	$444,269.50	$341,666.67	$102,602.83	$446,519.50	$341,666.67	$104,852.83	$2,250.00	0.5%
20,000	8,000,000	$870,707.00	$683,333.33	$187,373.67	$875,207.00	$683,333.33	$191,873.67	$4,500.00	0.5%

Present Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.34
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00212
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.26
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 500

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	% of Total
3,000	1,500,000	$174,832.00	$128,125.00	$46,707.00	$175,738.25	$128,125.00	$47,613.25	$906.25	0.5%
5,000	2,500,000	$279,498.67	$213,541.67	$65,957.00	$281,009.09	$213,541.67	$67,467.42	$1,510.42	0.5%
7,500	3,750,000	$410,332.00	$320,312.50	$90,019.50	$412,597.63	$320,312.50	$92,285.13	$2,265.63	0.6%
10,000	5,000,000	$541,165.33	$427,083.33	$114,082.00	$544,186.16	$427,083.33	$117,102.83	$3,020.83	0.6%
20,000	10,000,000	$1,064,498.67	$854,166.67	$210,332.00	$1,070,540.34	$854,166.67	$216,373.67	$6,041.67	0.6%

Present Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.34
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00212
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates: G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.26
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 600

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,800,000	$203,900.75	$153,750.00	$50,150.75	$205,038.25	$153,750.00	$51,288.25	$1,137.50	0.6%
5,000	3,000,000	$327,946.58	$256,250.00	$71,696.58	$329,842.42	$256,250.00	$73,592.42	$1,895.84	0.6%
7,500	4,500,000	$483,003.88	$384,375.00	$98,628.88	$485,847.63	$384,375.00	$101,472.63	$2,843.75	0.6%
10,000	6,000,000	$638,061.17	$512,500.00	$125,561.17	$641,852.83	$512,500.00	$129,352.83	$3,791.66	0.6%
20,000	12,000,000	$1,258,290.33	$1,025,000.00	$233,290.33	$1,265,873.67	$1,025,000.00	$240,873.67	$7,583.34	0.6%

<u>Present Rates:</u> G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00239
Distribution Demand Charge	kW x	$2.34
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment		$0.00230
Customer Credit	kWh x	-$0.00212
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> G-62

Customer Charge		$17,118.72
Transmission Demand Charge	kW x	$1.39
Transmission Adjustment Factor	kWh x	$0.00371
Distribution Demand Charge	kW x	$2.26
Distribution Energy Charge	kWh x	$0.00000
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.08200

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on T-06 (Phase-out to A-16) Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
500	$65.47	$42.71	$22.76	$67.64	$42.71	$24.93	$2.17	3.3%	3.0%
1,000	$128.07	$85.42	$42.65	$132.41	$85.42	$46.99	$4.34	3.4%	24.7%
2,000	$253.26	$170.83	$82.43	$261.94	$170.83	$91.11	$8.68	3.4%	13.9%
5,000	$628.85	$427.08	$201.77	$650.57	$427.08	$223.49	$21.72	3.5%	14.9%
10,000	$1,254.85	$854.17	$400.68	$1,298.28	$854.17	$444.11	$43.43	3.5%	7.2%
20,000	$2,506.82	$1,708.33	$798.49	$2,593.69	$1,708.33	$885.36	$86.87	3.5%	8.8%

<u>Present Rates:</u> T-06 (Phase-out to A-16)

Customer Charge		$2.75
Transmission Energy Charge (1)	kWh x	$0.00600
Distribution Energy Charge	kWh x	$0.02473
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit		-$0.00329
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

<u>Proposed Rates:</u> T-06 (Phase-out to A-16)

Customer Charge		$2.75
Transmission Energy Charge (2)	kWh x	$0.00732
Distribution Energy Charge	kWh x	$0.02699
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on T-06 (Phase-out to C-06) Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
500	$68.92	$42.71	$26.21	$71.53	$42.71	$28.82	$2.61	3.8%	2.7%
1,000	$131.59	$85.42	$46.17	$136.82	$85.42	$51.40	$5.23	4.0%	8.0%
2,000	$256.91	$170.83	$86.08	$267.37	$170.83	$96.54	$10.46	4.1%	17.3%
5,000	$632.91	$427.08	$205.83	$659.06	$427.08	$231.98	$26.15	4.1%	18.7%
10,000	$1,259.59	$854.17	$405.42	$1,311.88	$854.17	$457.71	$52.29	4.2%	17.3%
20,000	$2,512.91	$1,708.33	$804.58	$2,617.50	$1,708.33	$909.17	$104.59	4.2%	36.0%

Present Rates:	T-06 (Phase-out to C-06)	
Customer Charge		$6.00
Transmission Energy Charge (1)	kWh x	$0.00600
Distribution Energy Charge	kWh x	$0.02522
Transition Energy Charge	kWh x	$0.00845
C&LM Adjustment	kWh x	$0.00230
Customer Credit		-$0.00365
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Proposed Rates:	T-06 (Phase-out to C-06)	
Customer Charge		$6.00
Transmission Energy Charge (2)	kWh x	$0.00732
Distribution Energy Charge	kWh x	$0.02797
Transition Energy Charge	kWh x	$0.00575
C&LM Adjustment	kWh x	$0.00230
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08200

Note (1): Includes Transmission Adjustment Factor of $.00239/kWh.
Note (2): Includes Transmission Adjustment Factor of $.00371/kWh.

DIRECT TESTIMONY

OF

Michael D. Laflamme

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Michael D. Laflamme. My business address is 55 Bearfoot Road, Northboro, Massachusetts 01532.

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

A. I am Manager of Regulatory Support for National Grid USA Service Company, Inc. National Grid USA Service Company provides engineering, financial, administrative and other technical support to subsidiary companies of National Grid USA, including Narragansett Electric Company, d/b/a National Grid ("Narragansett", or "Company") and New England Power Company ("NEP"). Since my testimony refers to two National Grid companies, I will refer to the companies by their legal names as I've defined them.

Q. Please provide a brief summary of your educational background and training.

A. In 1981 I earned a Bachelor of Science degree in Business Administration, emphasis in Accounting, from Bryant College in Smithfield, Rhode Island.

Q. What is your professional background?

A. From 1981 through April 2000 I was employed by various subsidiary companies of Eastern Utilities Associates ("EUA"), including Blackstone Valley Electric Company ("Blackstone") and EUA Service Corporation ("EUASC") which provided various accounting, financial, engineering, planning, data processing and other services to all EUA System companies.

I joined Blackstone in 1981 as a junior accountant and attained a staff accountant position prior to transferring to the revenue requirements section of EUASC's Rate Department in 1985. I held progressively more responsible positions in revenue requirements prior to transferring to the Treasury Services department of EUASC in 1988. I was promoted to the position of Manager of Treasury Services in 1991. The EUA System was acquired by National Grid USA in early 2000, at which time I joined the National Grid USA Distribution Financial Analysis Group prior to attaining my current position in July 2002.

Q. What is your relationship to Narragansett and NEP?

A. My current duties include supporting cost of service and revenue requirements analyses for the National Grid USA Distribution companies in New England, including Narragansett and NEP. I am also responsible for the development of the Contract Termination Charge ("CTC") which is billed by NEP to Narragansett.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (the "Commission")?

A. Yes I have.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. I am providing support for NEP's estimated CTC to Narragansett for calendar year 2006. In addition, I will explain a NEP proposal, as more fully described in the June 21, 2005 CTC Mitigation Plan ("Plan") submitted to the Commission. In the Plan, NEP is seeking to modify its CTC to Narragansett due to the events surrounding the bankruptcy of USGen New England Inc. ("USGenNE") and NEP's subsequent receipt of $195 million of damages, plus interest of approximately $805,000 (collectively the "Allowed Claim").

III. CTC

Q. Would you briefly describe the CTC?

A. NEP, Narragansett, the Rhode Island Attorney General ("RIAG"), the Commission, and the Rhode Island Division of Public Utilities and Carriers (the "Division") entered into a comprehensive wholesale restructuring agreement that was approved by the Federal Energy Regulatory Commission ("FERC") in Docket Nos. ER97-680-000 and ER98-6-000 for NEP, and a parallel wholesale restructuring agreement in Docket No. ER97-2800-000 between the former Montaup Electric Company ("Montaup"), which has merged into NEP, and the former Blackstone and Newport Electric Corporation ("Newport"), which have merged into Narragansett ("Restructuring Settlement Agreements").

The CTC billed by NEP represents NEP's recovery of stranded generation costs resulting from utility industry restructuring in Rhode Island which provided for, among other things, retail choice of energy supply and NEP's divestiture of substantially all of its generation assets. The CTC also includes charges from the former Montaup to the former Blackstone and Newport. The formula for the Montaup CTC is nearly identical to that of the NEP CTC formula.

The CTC is a FERC-approved charge which contains two components, a fixed component and a variable component. The fixed component is designed to recover the above-market investments in generation assets of NEP and Montaup over a period ending in 2009. The fixed component recovery stream is not subject to reconciliation and its level is set through 2009. The variable component is designed to recover generation-related commitments such as above-market power purchase contract costs and nuclear decommissioning expenses, among other things. The variable component includes a stream of annual estimates of these variable obligations. The annual estimates included in the variable component are reconciled on an annual basis to actual expense incurred by NEP for those obligations, and any differences are billed or credited in the subsequent year's CTC via the reconciliation account. Changes to the level of fixed component recovery through 2009 or changes to the annual estimates of variable component costs must be approved by FERC.

IV. ESTIMATED 2006 CTC

Q. Has NEP calculated a preliminary Narragansett CTC for 2006?

A. Yes. NEP has calculated a preliminary CTC for 2006 based on the assumption that a settlement among the Company, NEP, the Commission, the Division, and the RIAG is approved by FERC. This settlement, a copy of which is attached herewith as Exhibit MDL-1, addresses the USGenNE bankruptcy, is consistent with the Plan referenced above, and is described below. Based on those assumptions, the estimated 2006 CTC for

Narragansett will be designed to collect $51.2 million or $12.1 million less than the 2005 CTC recovery of $63.3 million.

Q. What are the major factors contributing to this reduction?

A. Of the $12.1 million reduction, $8.4 million is the result of NEP's proposed application of Narragansett's share of the Allowed Claim proceeds, as discussed below. The remaining $3.7 million is the result of a preliminary reconciliation of the CTC variable component costs for the period October 2004 through September 2005 and is primarily due to greater than estimated kilowatt-hour deliveries. Details of this reconciliation will be provided in the 2005 CTC reconciliation report. The CTC reconciliation report is submitted annually to the Commission at the end of November.

V. THE PROPOSED CTC MITIGATION PLAN

Q. Would you briefly discuss the events surrounding the USGenNE bankruptcy proceeding and their impacts on the CTC?

A. Yes. As more fully described in the Plan, pursuant to terms of the divestiture of NEP's non-nuclear generation assets to USGenNE, USGenNE assumed certain obligations including, among other things, certain economic responsibilities pertaining to a number of power purchase contracts of NEP. As a result of USGenNE's bankruptcy, USGenNE breached these, and other, obligations and as a result, in June 2005 NEP received the Allowed Claim from USGenNE totaling $195.805 million.

The CTC formula provides that Narragansett is responsible for 22.4% of NEP's generation-related investments and obligations as defined in the formula, including, among other things, above-market purchased power costs. These above-market purchased power costs are defined in the post-divestiture CTC formula as "all payments by NEP for Long-Term Power Supply Contracts less the payments received from the Buyer or from resale of electricity purchased under the contracts into the wholesale market". Pursuant to the CTC formula, therefore, 22.4% of the Allowed Claim proceeds, or approximately $44 million, will be allocated to Narragansett and would be included in Narragansett's CTC reconciliation account in June 2005, and would be passed back to Narragansett in the 2006 CTC. Absent a filing at FERC requesting application of the proceeds in a different manner, this immediate refund of the proceeds over the twelve-month period would result in a very large single-year decrease in the CTC in 2006, followed by an equally large increase in the charge in 2007 as the one-time credit expires.

Q. Other than the benefits of CTC rate stability provided by the Plan, are there any other benefits of the proposed application of Narragansett's share of the Allowed Claim proceeds?

A. Yes there are. As discussed below, the proposed application will result in Narragansett's customers avoiding payment of approximately $8.1 million of return on the fixed assets being paid down in the proposal.

Q. Can you summarize the Plan which was filed with the Commission on June 21, 2005?

A. NEP has proposed to apply Narragansett's share of the Allowed Claim proceeds in a manner that will maximize the benefits for Narragansett's customers. First, it is important to understand that the CTCs from NEP and Montaup to Narragansett are simply aggregated at the distribution-company level to arrive at total costs to be recovered via Narragansett's nonbypassable transition charge. Consequently, changes in the CTCs to Narragansett or the former Blackstone or Newporrt, have the same effect on the nonbypassable transition charge. Therefore, while the obligations breached by USGenNE related to NEP obligations only, applying the Allowed Claim proceeds to the Montaup CTC calculations will have the same ultimate effect on the nonbypassable transition charge. Consequently, the Plan proposes to pay off a portion of the unrecovered stranded assets of Montaup, which will aggregate approximately $69 million at December 31, 2005. These assets represent the most expensive CTC costs for Narragansett's customers as they are recovered with a return through the fixed component of the CTC. The pre-tax return rate billed in the Montaup CTC formula is 12.16%. By paying off $44 million of Montaup's remaining stranded investments, customers avoid not only the repayment of those assets but also the return on those assets at the pre-tax return rate of 12.16%. This economic benefit is the same as the economic benefit one would enjoy from making an advanced payment of principal on a home mortgage and avoiding future interest charges on that amount of principal paid down. As shown on Exhibit MDL-2, this avoided return will aggregate approximately $8.1 million over the fixed asset recovery period which ends in 2009.

Q. Does the Plan's revised base CTC path contain any changes other than the proposed application of the Allowed Claim proceeds?

A. Yes. Because of USGenNE's breach of certain contractual obligations associated with the transfer of economic responsibility of a number of power purchase contracts of NEP, NEP has updated the CTC estimates for above-market purchased power costs in the base CTC path. In addition, as a result of FERC-approved and pending revisions to decommissioning estimates of the Yankee nuclear units, NEP has also revised decommissioning estimates included in the base CTC path. These updated estimates represent the most current estimates of variable CTC costs and will provide a better matching of cost incurrence and recovery.

Q. Do the Plan's revisions to the CTC comply with Restructuring Settlement Agreements?

A. Yes. The proposed application of Narragansett's share of the Allowed Claim proceeds and the proposed revisions to variable component cost estimates comply with the Restructuring Settlement Agreements approved by FERC.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.

Exhibits

Exhibit MDL-1

Settlement and CTC Implementation Agreement

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

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMMISSION

New England Power Company) Docket ER-___

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[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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SETTLEMENT AGREEMENT ATTACHMENTS

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

SETTLEMENT AGREEMENT ATTACHMENT 1

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

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

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

SETTLEMENT AGREEMENT ATTACHMENT 2

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

Narragansett Electric Company CTC Calculation

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

POST-DIVESTITURE
2004 CTC Reconciliation

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

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

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

$ in Millions

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

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

New England Power Company
Summary of Contract Termination Charges

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

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

Column Notes:

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

NO ADJUSTMENTS

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

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

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

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

NO ADJUSTMENTS

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

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

Settlement Agreement Notes:

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

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

NO ADJUSTMENTS

New England Power Company

FAS 106 Transition Obligation Regulatory Asset

$ in Millions

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

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

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

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

Based Upon Original Estimates

$ in Millions

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

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

New England Power Company Share of Total Annual Decommissioning Cost

Based Upon Revised Estimates

$ in Millions

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

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

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

Power Contract Buyout Payments Associated with Divestiture
Per IPP Transfer Agreement

$ Millions

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

Power Contract Obligations
Estimated Market Value

Based Upon Revised Estimates

$'s in millions

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

New England Power Company
Annual Utility Unit Sales Power Contracts

Based Upon Original Estimates

$ in Millions

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

Column Notes:

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

NO ADJUSTMENTS

New England Power Company
Fixed Costs of Gas Transportation
Contractual Commitments

Based Upon Original Estimates

Annual Expenses

$ in Millions

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

Columns Notes:

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

NO ADJUSTMENTS

Summary of Contract Termination Charges

New England Power Company (100%)
Fixed Component

$ in Millions

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

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

NO ADJUSTMENTS

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

Deferred Taxes on Fixed Component

$ in Millions

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

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

NO ADJUSTMENTS

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

Return on Fixed Component

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)
		Base Return							
(1)	Sept 1, 1998	$1,626	$370	$1,256					
(2)	**1998**	**1,424**	**303**	**1,121**	**$1,188**	**$50**	**($0.1)**	**$0.8**	**$50**
(3)	**1999**	**674**	**40**	**634**	**837**	**105**	**(0.1)**	**1.6**	**107**
(4)	**2000**	**0**	**(204)**	**204**	**419**	**53**	**(0.0)**	**0.5**	**53**
(5)	**2001**	**0**	**(186)**	**186**	**195**	**25**	**0.0**	**0.0**	**25**
(6)	**2002**	**0**	**(170)**	**170**	**178**	**22**	**0.0**	**0.0**	**22**
(7)	**2003**	**0**	**(155)**	**155**	**162**	**20**	**0.0**	**0.0**	**20**
(8)	**2004**	**0**	**(140)**	**140**	**148**	**19**	**0.0**	**0.0**	**19**
(9)	2005	0	(125)	125	133	17	0.0	0.0	**17**
(10)	2006	0	(111)	111	118	15	0.0	0.0	**15**
(11)	2007	0	(96)	96	104	13	0.0	0.0	**13**
(12)	2008	0	(82)	82	89	11	0.0	0.0	**11**
(13)	2009	0	(69)	69	75	9	0.0	0.0	**9**

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

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

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

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

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

Variable Component

$ in Millions

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

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

Reconciliation Adjustment

The Narragansett Electric Company Share

Revenue Adjustments

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

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

Reconciliation Adjustment

(continued from page 2a)

The Narragansett Electric Company Share

New England Power Company Variable Cost Adjustments

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

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

Reconciliation Account

The Narragansett Electric Company

The Narragansett Electric Company Account

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

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

Reconciliation Adjustment

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

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

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

Reconciliation Adjustment

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

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

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

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

Newport Electric Corporation CTC Calculation

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

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

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

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

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

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

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

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

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

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

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

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

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

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

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

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

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

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

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

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

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

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

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

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

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

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

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

Purchase Power Total $000

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

Purchase Power MWh

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

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

REVENUE ADJUSTMENTS ($000)

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

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

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

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

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

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

RECONCILIATION ADJUSTMENT **Schedule 2**
NEWPORT ELECTRIC COMPANY **Page 1c**
($000)

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

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

RECONCILIATION ADJUSTMENT CALCULATION
NEWPORT ELECTRIC COMPANY SHARE

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

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

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

Blackstone Valley Electric Company CTC Calculation

Print

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

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

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

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

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

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

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

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

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

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

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

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

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

MONTAUP ELECTRIC COMPANY
REGULATORY ASSET BALANCE
$ IN 000

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

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

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

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

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

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

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

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

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

S:\RADATA1\C T C\USGEN Settlement\Montaup Scenarios\Proposed CTC Rate\bve exhibit 31rev_prepetition_Oct7.XLS

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

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

MONTAUP ELECTRIC COMPANY
TOTAL ANNUAL DECOMMISSIONING COST
$ IN 000

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

Purchase Power Total $000

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

Purchase Power MWh

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

UNIT CONTRACT & NON AFFILIATE REVENUE CREDIT
$ IN 000

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

REVENUE ADJUSTMENTS ($000)

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

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

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY SHARE

MONTAUP ELECTRIC COMPANY VARIABLE COST ADJUSTMENT ($000)

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

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

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

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

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

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

RECONCILIATION ADJUSTMENT CALCULATION
BLACKSTONE VALLEY ELECTRIC SHARE

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

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

Exhibit MDL-2

Calculation of Avoided Return on Paydown of Montaup Fixed Assets

Calculation of Avoided Return on USGEN Bankruptcy Settlement Proceeds
Rhode Island CTC Calculation for Montaup

TABLE 1

Year	(a) Newport USGEN Proceeds Amort	(b) Return	(c) Total Value	(d) Blackstone USGEN Proceeds Amort	(e) Return	(f) Total Value	(g) Total R.I. USGEN Proceeds Amort	(h) Return	(i) Total Value
2006	$1,968	$946	$2,914	$4,825	$2,326	$7,151	$6,793	$3,271	$10,065
2007	$2,913	$747	$3,660	$7,099	$1,840	$8,939	$10,012	$2,587	$12,599
2008	$3,768	$475	$4,244	$9,250	$1,174	$10,424	$13,018	$1,650	$14,668
2009	$3,950	$161	$4,111	$9,797	$399	$10,196	$13,747	$560	$14,306
	$12,599	$2,329	$14,928	$30,971	$5,739	$36,710	$43,570	$8,068	$51,638

Column Notes
- (a) Table 2 Column (a) times -1
- (b) Table 2 Column (e)
- (c) Column (a) plus Column (b)
- (d) Table 2 Column (f) times -1
- (e) Table 2 Column (j)
- (f) Column (d) plus Column (e)
- (g) Column (a) plus Column (d)
- (h) Column (b) plus Column (e)
- (i) Column (g) plus Column (h)

TABLE 2

Year	(a) Newport Amort. Of USGEN Proceeds $43,570 28.92%	(b) Deferred Taxes (Sch 1 Pg 14) 33.04%	(c) Return Base	(d) Average Return Base	(e) R.I. Return 12.16%	(f) Blackstone Amort. Of USGEN Proceeds $43,570 71.08%	(g) Deferred Taxes (Sch 1 Pg 14) 33.04%	(h) Return Base	(i) Average Return Base	(j) R.I. Return 12.16%
1/1/06	$12,599	$4,163	$8,436			$30,971	$10,234	$20,737		
2006	($1,968)	($650)	$7,118	$7,777	$946	($4,825)	($1,594)	$17,507	$19,122	$2,326
2007	($2,913)	($962)	$5,168	$6,143	$747	($7,099)	($2,346)	$12,753	$15,130	$1,840
2008	($3,768)	($1,245)	$2,645	$3,906	$475	($9,250)	($3,056)	$6,560	$9,657	$1,174
2009	($3,950)	($1,305)	$0	$1,322	$161	($9,797)	($3,237)	$0	$3,280	$399

Column Notes
- (a) 1/1/06 amount equals 43,570 times 28.92%. 2006 through 2009 amounts equals 12,599 times Table 3 Column (b) amounts
- (b) Column (a) amounts times deferred tax percentage of 33.04% from Newport 2004 CTC Reconciliation Report Schedule 1 Page 14
- (c) Column (c) prior year plus current year Column (a) minus current year Column (b)
- (d) Average of Column (c) prior year and current year amounts
- (e) Column (d) times CTC return rate of 12.16%
- (f) 1/1/06 amount equals 43,570 times 71.08%. 2006 through 2009 amounts equals 12,599 times Table 3 Column (d) amounts
- (g) Column (f) amounts times deferred tax percentage of 33.04% from Blackstone 2004 CTC Reconcliliation Report Schedule 1 Page 14
- (h) Column (h) prior year plus current year Column (f) minus current year Column (g)
- (i) Average of Column (h) prior year and current year amounts
- (j) Column (d) times CTC return rate of 12.16%

TABLE 3

Year	(a) Newport Amortization Montaup Level	(b) Amort. Rate	(c) Blackstone Amortization Montaup Level	(d) Amort. Rate
2006	$31,242	15.62%	$32,994	15.58%
2007	$46,231	23.12%	$48,546	22.92%
2008	$59,817	29.91%	$63,254	29.87%
2009	$62,694	31.35%	$66,995	31.63%
Total	$199,984	100.00%	$211,789	100.00%

Column Notes
- (a) Annual Amortization of Gen. Related Investments & Reg. Assets per Newport 2004 CTC Reconciliation Report Schedule 1 Page 12
- (b) Column (a) amounts divided by Column (a) total
- (c) Annual Amortization of Gen. Related Investments & Reg. Assets per Blackstone 2004 CTC Reconciliation Report Schedule 1 Page 12
- (d) Column (c) amounts divided by Column (c) total

DIRECT TESTIMONY

OF

SUSAN L. HODGSON

Table of Contents

Testimony

Exhibits

I. <u>Introduction and Qualifications</u>

Q. Please state your name and business address.

A. My name is Susan L. Hodgson. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

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

A. I am employed by National Grid USA Service Company, Inc. ("Company") as Manager, Transmission Rates in the Transmission Finance group. My responsibilities include the administration and development of transmission tariffs and transmission rates for National Grid, which includes New England Power ("NEP") in New England and Niagara Mohawk Power Corporation in New York. My team provides support for NEP's transmission rate filings at the Federal Energy Regulatory Commission ("FERC"), monitors ISO New England ("ISO-NE") and New York ISO ("NYISO") Transmission Tariffs, and is involved with many transmission pricing policy and regulatory matters. Please note that, because my testimony refers to more than one National Grid company, I am using the old names of "Narragansett Electric" and "New England Power Company" in my testimony to make it easier to follow.

Q. Please describe your educational and professional background.

A. I graduated Magna Cum Laude from Syracuse University in Syracuse, New York in 1996 with a Bachelor of Science from the School of Management with a major in Managerial Statistics. I have held a number of positions with the Company, including Manager of Transmission & Delivery Services, and was a staff member in the Electric Pricing, the Regulatory Proceedings and the Power Contracts departments. I have submitted testimony to FERC in Docket No. ER97-1523-000 and have testified before FERC in Docket No. EL02-111-000, and have submitted testimony and testified in retail rate cases before the New York State Public Service Commission.

II. Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony addresses the estimated 2006 transmission expenses and ISO-NE expenses for The Narragansett Electric Company ("Narragansett"). First, I will summarize the various transmission services provided to Narragansett and how Narragansett pays for such services. Second, I will address the assumptions used in the development of Narragansett's estimated expenses for 2006 as shown in Exhibit SLH-1. Lastly, I will briefly explain the primary changes from last year's forecasted expenses.

III. Summary of Transmission Services Provided to Narragansett

Q. Please explain the history of Narragansett's transmission service under rate schedules approved by the FERC.

A. Effective January 1, 1998, Narragansett began taking transmission services, on behalf of its entire customer base, under two tariffs: NEPOOL's FERC Electric Tariff No. 1 ("NEPOOL Tariff") and NEP's FERC Electric Tariff No. 9 ("NEP T-

9 Tariff"). Additionally, effective January 1, 1999, Narragansett began taking service under ISO-NE's FERC Electric Tariff No. 1 ("ISO-NE Tariff"). However, on February 10, 2005, FERC issued an order authorizing ISO-NE to begin operating as a Regional Transmission Operator ("RTO") effective as of February 1, 2005, ("ISO as the RTO"). At that time, ISO-NE replaced NEPOOL as the transmission provider in New England. The new ISO New England Transmission, Markets and Services Tariff ("ISO/RTO Tariff") replaced the three separate tariffs referred to above by aggregating them into a single, omnibus tariff. Narragansett is now only charged by NEP and ISO as the RTO under this superseding omnibus tariff, as NEPOOL ceased to exist as a transmission provider in New England. The terms, conditions and rate schedules from these three separate tariffs have been transferred to the ISO/RTO Tariff as follows: the NEP T-9 Tariff is captured in Schedule 21 and Schedule 21-NEP, the NEPOOL Tariff is captured in Section II (up through and including Schedule 19), and the ISO-NE Tariff is captured in Section IV.A. The prospective charges to Narragansett, therefore, are separately identified as NEP local charges, ISO regional charges (formerly NEPOOL), and ISO/RTO administrative charges.

Q. Please describe further the types of transmission service that Narragansett is billed for under the ISO/RTO Tariff.

A. New England's transmission rates utilize a highway/local pricing structure. That is, Narragansett receives regional transmission service over "highway" transmission facilities under Section II of the ISO/RTO Tariff, and receives local transmission service over local transmission facilities under Schedule 21 of the ISO/RTO Tariff. Additionally, transmission scheduling and market administration services are provided to Narragansett under Section IV.A of the ISO/RTO Tariff.

A. Explanation of ISO/RTO Tariff Services, Rates & Charges

Q. Please explain the services provided to Narragansett under the ISO/RTO Tariff.

A. Section II of the ISO/RTO Tariff provides access over New England's 69kV or greater looped transmission facilities, more commonly known as Pool Transmission Facilities ("PTF") or bulk transmission facilities. These facilities serve as New England's electric transmission "highway", and the service provided over these facilities is referred to as Regional Network Service ("RNS"). In addition, the ISO/RTO Tariff provides for Black Start, Reactive Power, and Scheduling, System Control and Dispatch Services, as described more fully later in this testimony.

Q. How are the costs for RNS recovered?

A. The ISO RNS Rate ("RNS Rate") recovers the RNS costs and is determined annually based on an aggregation of the transmission revenue requirements of each of the transmission owners in New England, calculated in accordance with a FERC-approved formula. Pursuant to a NEPOOL Settlement dated April 7, 1999, and incorporated into the ISO/RTO Tariff, the RNS Rate continues to be in a period of transition as the transmission rates move from zonal rates to a single, "postage stamp" rate in New England. The transition will be complete in 2008 ("NEPOOL Transition"). The NEPOOL Transition provides for a unique rate derivation in that each transmission owner's RNS rate is determined by looking separately at the costs associated with vintage PTF assets: (1) in-service at December 1996 ("Pre-97 Property"), and (2) placed in-service after January 1, 1997 ("Post-96 Property").

Q. Please explain the rate derivation for Pre-97 Property under the ISO/RTO Tariff.

A. As mentioned above, the intent of the NEPOOL Transition is to move zonal transmission rates that previously had been in place in New England to a single, postage-stamp rate for the region. As part of that transition process, until the end of the transition period (2008), each transmission owner's zonal Pre-97 RNS Rate is adjusted based on the differential of the individual transmission owner's Pre-97 PTF Rate to the average Pre-97 Pool PTF Rate, based on a bandwidth which limits the variation of a transmission owner's per kilowatt cost from the average per kilowatt cost for all transmission owners. The bandwidth will shrink each year, moving the Pre-97 PTF Rate closer to the average until 2008 when the NEPOOL transition is complete and all PTF costs are recovered on a regionalized average basis**.** For example, in 2006, a bandwidth of 50% below the average and 112% above the average has been established, where each transmission owner's Pre-97 PTF Rate is held within that established bandwidth. To the extent a transmission owner's actual rate is less than 50% below the average or exceeds 112% of the average, the remaining transmission owners' rates are adjusted to collect/refund the revenue requirements falling outside the bandwidth. In that way, all transmission owners' rates reflect a movement towards an average, postage-stamp rate.

Q. Please explain the rate derivation for the Post-96 Property under the ISO/RTO Tariff.

A. The Post-96 Property rates apply a single, average New England-wide transmission rate based upon the average Post-96 revenue requirements for all New England transmission owners.

Q. Are there any expected changes to the RNS Rate during 2006?

A. Yes. Although NEP's Pre-97 PTF Rate for 2006 is not expected to exceed the bandwidth and thus no significant change to NEP's Pre-97 PTF Rate is forecast, the ISO Post-96 PTF Rate will reflect plant additions, as well as adjustments to the rates based on the methodologies described above. Exhibit SLH-1, Workpaper Page 1, attached hereto, illustrates the changes to the RNS Rate.

Q. Please describe the ISO Black Start, Reactive Power, and Scheduling, System Control and Dispatch Services that are included in the ISO/RTO Tariff.

A. ISO Black Start Service, also known as System Restoration and Planning Service from Generators, is necessary to ensure the continued reliable operation of the New England transmission system. This service allows for the designation of generators with the capability of supplying load and ability to start without an outside electrical supply to re-energize the transmission system following a system-wide blackout.

Reactive Power Service, also known as Reactive Supply and Voltage Control from Generation Sources Service, is necessary to maintain transmission voltages on the ISO transmission system within acceptable limits and requires that generation facilities be operated to produce or absorb reactive power. This service must be provided for each transaction on the ISO transmission system. The amount of reactive power support that must be supplied for transactions is based on the support necessary to maintain transmission voltages within limits generally accepted and is consistently sustained in the region.

Lastly, Scheduling, System Control and Dispatch Service ("Scheduling & Dispatch Service") consists of the ISO services required to schedule at the ISO level the movement of power through, out of, within, or into the ISO Control Area over the PTF and to maintain System Control. Scheduling & Dispatch Service also provides for the recovery of certain charges that reflect expenses incurred in the operation of satellite dispatch centers.

Q. How are the ISO charges for Black Start, Reactive Power, and Scheduling & Dispatch Services assessed to Narragansett?

A. The ISO assesses charges for Black Start and Reactive Power Services to Narragansett each month based on Narragansett's proportionate share of its network load to ISO's total load. Exhibit SLH-1, Workpaper Page 3 illustrates the ISO rates for Black Start and Reactive Power Services and applies the charges to Narragansett's loads. Scheduling and Dispatching costs are assessed to Narragansett based on an annually determined rate, calculated in accordance with a FERC-approved formula, multiplied by Narragansett's total network load.

Q. Are there any other applicable ISO charges which you have not mentioned previously in this testimony?

A. Yes. The ISO/RTO Tariff also charges for costs associated with Reliability Must Run ("RMR") contracts.

Q. What are RMR contracts?

A. RMR generation resources are those resources identified as necessary to maintain the reliability of the ISO transmission system (e.g., to provide operating reserve requirements and adherence to North American Electric Reliability Council, Northeast Power Coordinating Council and ISO reliability criteria). For resources that expect to be uneconomic and would otherwise seek authority to shut-down permanently, a cost-of-service contract is implemented for monthly fixed-cost compensation so that resource can remain available to serve reliability needs. That contract is the RMR contract.

Q. How are these RMR contract costs allocated?

A. Any monthly charges paid to RMR resources are allocated to the Network Loads within the affected reliability region during that month. Thus, there may or may not be RMR-related costs assessed to Narragansett.

Q. What services are provided to Narragansett under Section IV.A of the ISO/RTO Tariff?

A. The ISO provides three types of services under Section IV.A of its ISO/RTO Tariff. These services include Scheduling & Dispatch Service, Energy Administration Service (“EAS”) and Reliability Administration Service (“RAS”). As mentioned previously, Scheduling & Dispatch Service is the service required to schedule at the ISO level the movement of power through, out of, within, or into the ISO Control Area over the PTF. For transmission service under the ISO/RTO Tariff, scheduling service is an ancillary service that can only be provided by the ISO. Thus, the ISO’s charges for Scheduling & Dispatch Service are based on the expenses incurred by the ISO in providing this service. EAS and RAS are the services provided by the ISO to administer the Energy Market and Reliability Market, respectively. In addition, Section IV.A of the ISO/RTO Tariff, Schedule 4, provides for the collection of FERC Annual Charges. I have included an estimated value for the FERC Annual Charges in this filing.

Q. How are the ISO/RTO Tariff charges assessed?

The ISO assesses the charges in Section IV.A, excluding Schedule 4, based upon stated rates pursuant to the ISO/RTO Tariff. These stated rates are adjusted annually when the ISO files a revised budget and cost allocation proposal to become effective January 1st each year. Narragansett is charged the stated rate for these services as part of the ISO's monthly billing process, based on its network load for Schedule 1 charges and electrical load for Schedules 2 and 3 charges. Schedule 4 charges are based upon FERC's total assessment to the New England Control Area, and further assessed to NEP based on its proportion of total MWhs of transmission to the total of the New England Control Areas' total MWhs. NEP, in turn, allocates a portion of its total charges to Narragansett based on Narragansett's MWhs to NEP's total MWhs.

B. <u>Explanation of Schedule 21 Tariff Services & Charges</u>

Q. What services are provided to Narragansett under Schedule 21 of the ISO/RTO Tariff?

A. Schedule 21 provides service over NEP's local, non-highway transmission facilities, considered non-PTF facilities ("Non-PTF"). The service provided over the Non-PTF is referred to as Local Network Service ("LNS"). NEP also provides metering, transformation and certain ancillary services to Narragansett to the extent such services are required by Narragansett and not otherwise provided under the ISO/RTO Tariff.

Q. Please explain the metering and transformation services provided by NEP.

A. NEP separately surcharges the appropriate customers for these services. NEP provides metering service when a customer uses NEP-owned meter equipment to measure the delivery of transmission service. NEP provides transformation service when a customer uses NEP-owned transformation facilities to step down voltages from 69 kV or greater to a distribution voltage.

IV. Estimate of Narragansett's Transmission Expenses

Q. Did you estimate Narragansett's transmission and ISO expenses for 2006?

A. Yes. Based on my knowledge of the ISO billing processes, I estimate the total transmission and ISO expenses (including certain ancillary services) for 2006 to be approximately $52.8 million, as shown in Exhibit SLH-1, Summary Page 1.

Q. How have the estimated 2006 RNS transmission charges been determined?

A. As indicated in Exhibit SLH-1, Workpaper Page 1, I have applied estimates of the RNS rates and adjusted them to reflect (1) the NEPOOL Transition described earlier in my testimony and (2) an estimated rate increase to the Post-96 PTF Rate to reflect a forecast of capital expenditures for New England, as provided by the New England transmission owners, that would be included in the annual formula rate effective June 1st each year. The estimated 2006 RNS transmission charges to Narragansett are then calculated by taking this forecasted RNS rate, divided by 12, multiplied by Narragansett's monthly network load.

Q. How have the estimates for ISO Black Start, Reactive Power and Scheduling and Dispatch Services been determined?

A. The estimated cost for Black Start Service is based on the July 2005 Black Start level of 153,246 kW for 12 months multiplied by the January 1, 2006 rate of $4.50/kW-Yr. This estimate of $8.28 million for the New England region for Black Start Service, as shown in Exhibit SLH-1, Workpaper Page 3, is divided by the ISO's 2004 Network Load to calculate an estimated annual rate. The monthly rate (annual rate divided by 12) is then multiplied by Narragansett's monthly network load to determine the estimated charges for Black Start Service.

The estimated Reactive Power cost of $115.4 million for the New England region is calculated by using the actual costs for the period August 2004 through July 2005, as shown in Exhibit SLH-1, Workpaper Page 3. The annual rate is determined by dividing the total Reactive Power costs by the ISO's 2004 Network Load. The monthly rate (annual rate divided by 12) is then multiplied by Narragansett's monthly network load to determine the estimated charges for Reactive Power Service.

Finally, Narragansett's estimate for Scheduling and Dispatch Service is based on the currently effective rate of $0.96648, divided by 12, and further multiplied by Narragansett's network load for the period August 2004 through July 2005.

Q. Have you included any RMR contract charges to Narragansett for 2006?

A. No. Narragansett has not incurred any RMR contract charges as there have been no RMR contracts for the Rhode Island reliability region over the past year. Therefore, I have not forecasted any RMR contract costs for 2006.

Q. How have the estimated charges to Narragansett under Schedule 21 of the ISO/RTO Tariff been determined and how are these charges allocated to Narragansett's customers?

A. As shown in Exhibit SLH-1, Workpaper Page 2, a base value for NEP's Non-PTF expenses are increased by $4.6 million to reflect the additional costs associated with forecasted capital additions anticipated for the rate period. NEP allocates Non-PTF expenses to Narragansett's customers on a load ratio share basis, as shown in Exhibit SLH-1, Transmission Charges Page 1. Metering, transformation and ancillary service charges are based on current rates and are assessed to Narragansett based on a per meter and peak load basis, respectively.

Q. How have the estimated 2006 ISO/RTO Tariff charges been determined?

A. The ISO's charges to Narragansett are based on the ISO revenue requirement filed each year with FERC. The ISO filed its proposed 2006 revenue requirement with FERC on October 31, 2005. To estimate Narragansett's 2006 ISO charges, the ISO's actual costs for the period August 2004 through July 2005 are adjusted by an inflationary factor as shown in Exhibit SLH-1, Transmission Charges Page 3. This inflationary factor is intended to recognize the increase or decrease in the

ISO's revenue requirement and the associated components of that revenue requirement from the budget as filed for the previous year.

Q. Are there any further adjustments to Narragansett's forecasted transmission costs for the year 2006?

A. Yes. I have included an additional item in the forecast of Narragansett's transmission costs associated with the Chester SVC and AC reinforcement charges that were not included in the prior year's forecast. These costs were inadvertently recorded to a generation-related account on NEP's books instead of being recorded to a transmission-related account, as should have been the case. Therefore, the prior year's transmission forecast would not have correctly identified these costs as transmission since they were not recorded in a transmission account. NEP will make an accounting adjustment to reclassify actual costs incurred to date and reflect the adjustment on its transmission bill in the same month. At the same time, NEP will credit its CTC by the same amount.

Q. Does your estimate of Narragansett's 2006 expenses for transmission service and ISO related services represent an increase or decrease from the level included in Narragansett's current retail rates?

A. The estimated 2006 Narragansett transmission and ISO expenses of $52.8 million represents a net increase of $8.6 million from the 2005 forecast of transmission expenses for Narragansett. This net increase is primarily due to transmission plant investment forecast for 2006 for all of New England ($3.7M) and the proposed ISO charges for reactive power ($4.2M).

V. <u>Explanation of Primary Changes from Last Year's Forecasted Expenses</u>

Q. What factors are driving the increase in the PTF expense forecast for 2006?

A. The estimated $3.7 million increase to the 2006 forecast of ISO PTF transmission expenses is primarily due to an expected investment value of all New England Transmission Owners of over $850M – the most significant of which relate to: (1) the Northwest Vermont Reliability Project: $120M; (2) NSTAR 345 kV Reliability Project: $261M; and (3) Southwest Connecticut Reliability Project: $411M. Exhibit SLH-2 to my testimony is an excerpt from the Regional System Plan 2005 approved by the ISO New England Board of Directors, Section 8 – Transmission Projects which describes in more detail the major projects itemized above. The complete version of the Regional System Plan can be found at *http://www.iso-ne.com/trans/rsp/2005/102005_RSP05_Final_redacted.pdf*

Q. Please discuss the $4.2M increase in reactive power.

A. The increase in reactive power is attributed to the fact that Boston area generators were called upon by the ISO to supply VAR capability to Boston. Exhibit SLH-3 to my testimony provides a presentation to the ISO's Transmission Committee from March 2005 that discusses the events that lead to the rise in VAR costs.

Q. Does this conclude your testimony?

A. Yes.

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Exhibit SLH-1

National Grid: Narragansett Electric Company
Summary of Transmission Expenses
Estimated For the Year 2006

	NEP Charges		
1	Non-PTF	$13,454,942	
2	Other NEP Charges	$1,268,385	
	Sub-Total NEP Charges		$14,723,327
	ISO Charges		
3	PTF	$27,147,874	
4	Scheduling & Dispatch	$1,271,387	
5	Reliability Must Run	$0	
6	Black Start	$528,823	
7	Reactive Power	$7,381,434	
	Sub-Total ISO Charges		$36,329,518
8	Schedule 1 - Scheduling & Dispatch	$1,267,136	
9	Schedule 2 - Energy Administration	$290,210	
10	Schedule 3 - Reliability Administration	$222,606	
	Sub-Total ISO-NE Charges		$1,779,952
11	Total Expenses Flowing Through Current Rates		$52,832,798

Line 1 = Page 1 of 3: Column (2), Line 13
Line 2 = Page 1 of 3: Sum of Column (3) thru (5), Line 13
Line 3 = Page 2 of 3: Column (2), Line 13
Line 4 = Page 2 of 3: Column (3), Line 13
Line 5 = Page 2 of 3: Column (4), Line 13
Line 6 = Page 2 of 3: Column (5), Line 13
Line 7 = Page 2 of 3: Column (6), Line 13
Line 8 = Page 3 of 3: Column (1), Line 17
Line 9 = Page 3 of 3: Column (2), Line 17
Line 10 = Page 3 of 3: Column (3), Line 17
Line 11 = Sum of Line 1 thru Line 10

National Grid: Narragansett Electric Company
Summary of New England Power - Schedule No. 21 Charges
Estimated For the Year 2006

		Non- PTF Load Ratio % Share (1)	Non-PTF Demand Charge (2)	Scheduling & Dispatch (3)	Transformer Surcharge (4)	Meter Surcharge (5)	Chester SVC & AC (6)	Total NEP Costs (7)
1	January	24.74%	$1,097,367	$31,754	$2,179	$1,124	$49,134	$1,181,558
2	February	21.85%	969,178	71,968	$2,179	$1,124	$43,395	$1,087,844
3	March	25.01%	1,109,343	126,006	$2,179	$1,124	$49,671	$1,288,323
4	April	24.97%	1,107,569	54,092	$2,179	$1,124	$49,591	$1,214,555
5	May	25.09%	1,112,891	75,648	$2,179	$1,124	$49,829	$1,241,671
6	June	25.82%	1,145,271	65,264	$2,179	$1,124	$51,279	$1,265,117
7	July	26.05%	1,155,473	23,586	$2,179	$1,124	$51,736	$1,234,098
8	August	26.76%	1,186,966	43,945	$2,179	$1,124	$53,146	$1,287,360
9	September	26.94%	1,194,950	13,323	$2,179	$1,124	$53,504	$1,265,080
10	October	25.63%	1,136,844	31,397	$2,179	$1,124	$50,902	$1,222,446
11	November	25.63%	1,136,844	28,262	$2,179	$1,124	$50,902	$1,219,311
12	December	24.85%	1,102,246	61,016	$2,179	$1,124	$49,353	$1,215,918
13	12- Mo Total		$13,454,942	$626,261	$26,148	$13,488	$602,442	$14,723,281
14	FERC Assessment							$46.00

Lines 1-12: Column (1) & (3) = Monthly Network Bills for period August 2004 thru July 2005
Lines 1-12: Column (4) & (5) = Current rate as of July 2005
Lines 1-12: Column (2) = Column (1) * Workpaper 2 of 3, Line 16 / 12
Lines 1-12: Column (6) = Chester SVC support expense
Lines 1-12: Column (7) = Sum of Column (2) thru (6)
Line 13 = Sum of Line 1 thru Line 12
Line 14 = FERC Assessment

National Grid: Narragansett Electric Company
Summary of ISO Charges
Estimated For the Year 2006

		Monthly PTF kW Load (1)	PTF Demand Charge (2)	Scheduling & Dispatch (3)	Reliability Must Run (4)	Black Start (5)	Reactive Power (6)	Total ISO (7)
1	January	1,331,773	$1,871,946	$107,261	$0	$44,614	$622,737	$2,646,558
2	February	1,208,807	1,699,104	$97,357	$0	40,495	565,238	2,402,194
3	March	1,232,317	1,742,471	$99,251	$0	41,283	576,231	2,459,236
4	April	1,038,959	1,469,066	$83,678	$0	34,805	485,817	2,073,366
5	May	1,028,532	1,454,323	$82,838	$0	34,456	480,942	2,052,559
6	June	1,614,657	3,070,237	$130,045	$0	54,091	755,014	4,009,387
7	July	1,754,213	3,335,599	$141,284	$0	58,766	820,270	4,355,919
8	August	1,603,964	3,049,904	$129,183	$0	53,733	750,014	3,982,834
9	September	1,396,834	2,656,051	$112,501	$0	46,794	653,160	3,468,506
10	October	1,101,830	2,095,107	$88,741	$0	36,911	515,216	2,735,975
11	November	1,101,830	2,095,107	$88,741	$0	36,911	515,216	2,735,975
12	December	1,372,068	2,608,959	$110,506	$0	45,964	641,579	3,407,008
13	12-Mo Total	15,785,784	$27,147,874	$1,271,387	$0	$528,823	$7,381,434	$36,329,518

Line 1-12: Column (1) = NEPOOL Monthly Statement August 2004 - July 2005
Line 1-2: Column (2) = Workpaper, Page 1 of 3, Line 3 * Column (1) / 12
Line 3-5: Column (2) = Workpaper, Page 1 of 3, Line 6 * Column (1) / 12
Line 6-12: Column (2) = Workpaper, Page 1 of 3, Line 13 * Column (1) / 12
Line 1-12: Column (3) = Current Rate * Column (1) / 12 Rate = 0.96648 /kW-Yr
Line 1-12: Column (4) = 0 [No Reliability Must Run Contracts are currently in effect for Rhode Island]
Line 1-12: Column (5) = Workpaper, Page 3 of 3, Line 8 * Column (1)
Line 1-12: Column (6) = Workpaper, Page 3 of 3, Line 4 * Column (1)
Line 1-12: Column (7) = Sum of Columns (2) thru (6)
Line 13 = Sum of Line 1 thru Line 12

National Grid: Narragansett Electric Company
Summary of ISO-NE Charges
Estimated For the Year 2006

		Sch. 1 Scheduling & Dispatch (1)	Sch. 2 Energy Administration (2)	Sch. 3 Reliability Administration (3)	Total ISO-NE Charges (4)
1	January	$100,100	$47,981	$31,706	$179,787
2	February	$97,600	$48,981	$34,606	$181,187
3	March	$89,200	$8,681	$4,606	$102,487
4	April	$90,700	$8,681	$4,806	$104,187
5	May	$75,700	$2,481	$906	$79,087
6	June	$74,400	$16,181	$15,806	$106,387
7	July	$117,600	$2,381	$406	$120,387
8	August	$128,300	$2,381	$4,606	$135,287
9	September	$116,200	$47,081	$36,006	$199,287
10	October	$100,200	$54,381	$41,106	$195,687
11	November	$80,000	$9,781	$6,206	$95,987
12	December	$84,000	$87,981	$52,906	$224,887
13	Sub-Total	$1,154,000	$336,972	$233,670	
14	2005 Budget	$19,074,765	$75,523,753	$29,283,747	$123,882,265
15	2006 Budget	$20,944,826	$65,043,204	$27,897,235	$113,885,265
16	% Change	9.80%	-13.88%	-4.73%	-8.07%
17	Estimate	$1,267,136	$290,210	$222,606	$1,779,952

Line 1-12: Column (1) thru (3) = Monthly ISO Bills for period August 2004 thru July 2005
Line 13 = Sum of Line 1 thru Line 12
Line 14 = ISO-NE Proposed Operating Budget (Year 2005)
Line 15 = ISO-NE Proposed Total Operating Budget (Year 2006) based on 10/31/05 FERC filing
Line 16 = Line 15-Line 14 / Line 14
Line 17: Column (1) thru (3) = Line 13 + (Line 13*Line 16); Column (4) = Sum of Columns (1) thru (3)

Workpaper SLH-1

New England Power Company
PTF Rate Calculation
Non-PTF Revenue Requirement
Estimated For the Year 2006

	Development of PTF Rate:			
1	Currently Effective NEP PTF Rate	Pre -97	$11.85	/KW-YR
2	Currently Effective ISO PTF Rate	Post-96	$5.02	/KW-YR
3	Total Regional Network Service Rate through February 28, 2006		$16.87	/KW-YR
	ESTIMATED Rate Effective March 1, 2006 through May 31, 2006:			
4	Estimate Change in Rate - NEP PTF Rate	Pre -97	$11.95	/KW-YR
5	Currently Effective ISO PTF Rate	Post-96	$5.02	/KW-YR
6	Total Regional Network Service Rate March 1, 2006 through May 31, 2006		$16.97	/KW-YR
	ESTIMATED Increase in ISO Rate Effective June 1, 2006			
7	Total ESTIMATED ISO Post-96 Plant Additions		$853,335,000	
8	* Post 96 Rev. Req. to Plant Ratio		14.1%	
9	/ 2004 ISO Network Load		20,562,032	
10	Additional Estimated ISO Post-96 Rate		$5.85	/KW-YR
11	Pre-97 Rate		$11.95	/KW-YR
12	Estimated Post-96 Rate		$10.87	/KW-YR
13	Total Regional Network Service Rate in effect June 1, 2006 through February 28, 2007		$22.82	/KW-YR

Line 1 & 2 = PTO Informational Filing dated 10/21/05, as amended
Line 3 = Line 1 + Line 2
Line 4 = Recalculation of RNS Rate using the change in bandwidth per Schedule 9 ISO/RTO Tariff
Line 5 = PTO Informational Filing dated 10/21/05, as amended
Line 6 = Line 4 + Line 5
Line 7 = Total ISO 2006 Capital Additions Estimates as provided by Transmission Owners
Line 8 = Average ISO Post-96 Rev. Requirement to Plant Ratio - 2004
Line 9 = PTO Informational Filing dated 10/21/05, as amended
Line 10 = Line 7 * Line 8 / Line 9
Line 11 = Line 4
Line 12 = Line 5 + Line 10
Line 13 = Line 11 + Line 12

New England Power Company
PTF Rate Calculation
Non-PTF Revenue Requirement
Estimated For the Year 2006

Section II:

14	NEP's Schedule 21 Non-PTF Revenue Requirement (12 mos. Ended 8/31/05)	$48,642,737
15	Adjustment for Forecasted 2006 Capital Additions	$4,584,433
16	Estimated 2006 Non-PTF Revenue Requirement	$53,227,170
	Adjustment for Year End 2005 Capital Additions	
17	Estimated 2006 Non-PTF Transmission Capital Expenditures for Lines	$7,752,000
18	Est. 2006 Non-PTF Transmission Capital Expenditures for Substations	$25,310,100
19	Estimated Percentage Transferred to Plant in 2006 for Substations	70%
20	Estimated NEP 2006 Transmission Plant Additions	$25,469,070
21	Non-PTF Transmission Plant Carrying Charge	18%
22	Adjustment for Forecasted 2006 Capital Additions	$4,584,433

Section III:

	Transmission Plant Carrying Charge	
23	NEP's Schedule 21 Revenue Requirement	$48,642,737
24	Total Revenue Credit (12 Mos. Ended 7/31/05)	$147,266,541
25	Total Transmission Integrated Facilities Credit (12 Mos. Ended 7/31/05)	($35,452,697)
26	Sub-Total	$160,456,581
27	Total Transmission Plant (as of 7/31/05)	$916,883,588
28	Non-PTF Transmission Plant Carrying Charge	18%

Line 14 = NEP Schedule 21 Billing
Line 15 = Line 22
Line 16 = Line 14 + Line 15
Line 17 & 18 = Transmission Capital Budget * 30% to estimate Non-PTF portion:
Line 19 = Engineering Estimate for Substations
Line 20 = Line 17 + (Line 18 * Line 19)
Line 21 = Line 28
Line 22 = Line 20 * Line 21
Line 23 thru 25 = NEP Schedule 21 Billings
Line 26 = Sum of Lines 23 thru 25
Line 27 = NEP Schedule 21 Billing
Line 28 = Line 26 / Line 27

National Grid: Narragansett Electric Company
Summary of Reactive Power & Black Start Costs
Estimated For the Year 2006

Section I: Development of Reactive Power Estimate

1	Estimated Total ISO Reactive Power Costs	$115,369,057
2	2005 ISO Network Load (KW)	20,562,032
3	Estimated Rate / KW-Yr	$5.6108
4	Estimated Rate / KW-Mo	$0.4676

Section II: Development of Black Start Costs

5	Estimated Total ISO Black Start Costs	$8,275,306
6	2005 ISO Network Load (KW)	20,562,032
7	Estimated Rate / KW-Yr	$0.4025
8	Estimated Rate / KW-Mo	$0.0335

Line 1 = ISO Schedule 2 Settlement Reports for period August 2004 thru July 2005
Line 2 = 12 CP Network Loads from Informational Filing dated 10/21/05
Line 3 = Line 1 / Line 2
Line 4 = Line 3 / 12
Line 5 = August 2005 Black Start Settlement Reports * Current Rate of $4.50 * 12 [ISO/RTO C
Line 6 = Line 2
Line 7 = Line 5 / Line 6
Line 8 = Line 7 / 12

Exhibit SLH-2

Section 8
Transmission Projects

Much progress has been made over the past few years regarding transmission projects. Seventy-five projects have been placed in service since RTEP01 totaling $217 million in construction costs. Five of the region's six major 345 kV projects are in various stages of development, with state siting approval either completed or underway. Section 8 provides an update on the progress of the current major transmission efforts in New England and describes the needed transmission improvements to load or generation pockets.

8.1 Major Transmission Projects

This section summarizes the main features of the six major transmission projects in New England. They are considered major in terms of their potential specifications, costs, and how they will improve the transmission system; most involve new 345 kV transmission lines. The projects are as follows:

- Northeast Reliability Interconnect Project
- Northern New England Transmission Transfer Capability Project
- Northwest Vermont Reliability Project
- NSTAR 345 kV Transmission Reliability Project
- SWCT Reliability Project, Phase 1 and Phase 2
- Southern New England Reinforcement Project

8.1.1 Northeast Reliability Interconnect Project

The Northeast Reliability Interconnect Project, also known as the Second New Brunswick Tie Project, is proceeding. It is comprised of a new 144-mile, 345 kV transmission line connecting Le Preau Substation in New Brunswick to Orrington Substation in northern Maine along with supporting equipment. It is designed to increase transfer capability from New Brunswick to New England by 300 MW.

The ISO reviewed and approved the proposed plan in early 2003. The stakeholder transmission cost review, which was completed in mid-2004, determined that the $90.4 million total U.S. cost of this project should be included in the regional transmission rate, which the ISO then approved. As is typical, the final actual cost of the constructed project may vary from the estimated cost and continues to be subject to review per the ISO tariff.

The project's application for a Certificate of Public Convenience and Necessity from the Maine Public Utility Commission (PUC) was approved in July 2005. The project is currently undergoing two other regulatory proceedings as follows:

- Application for an environmental permit from the Maine Department of Environmental Protection (DEP)
- Request for a Presidential Permit from the U.S. Department of Energy required for international tie lines

The planned in-service date for this project is the end of 2007.

8.1.2 Northern New England Transmission Transfer Capability Project

The ISO is conducting analyses to identify upgrades that will increase the transfer capabilities of the northern New England interfaces and reduce operational complexity by reducing the interdependencies of specific generators on the transfer capability. The Surowiec–South, Maine–New Hampshire, and northern

New England Scobie and 394 interfaces are most notably affected by these analyses. The ISO has identified alternatives, as follows, to address these issues, either individually or in combination:

• **Closing the Y-138 line.** This project, actively being pursued to address central New Hampshire reliability needs, also will provide some limited increase to the Surowiec–South and Maine–New Hampshire voltage and thermal limitations. This project is currently estimated to cost $20 million. It is anticipated that the proposed project plan will be submitted for review in late 2005.

• **Adding a 500–600 MVAR static compensator to provide dynamic voltage control at the Deerfield 345 kV Substation.** This project would reduce the complexities and interdependencies of generators on the voltage limits of the Maine–New Hampshire interface and could also increase the Maine–New Hampshire and northern New England Scobie and 394 interface stability limitations. This potential alternative is currently estimated to cost $25 million.

• **Eliminating critical Buxton 345 kV contingencies resulting from the failure of key circuit breakers to operate.** This project would increase the steady-state and stability limitations of the Surowiec–South and Maine–New Hampshire interfaces. This potential alternative is currently estimated to cost $5 million.

• **Looping Section 391 into the Deerfield 345 kV Substation.** This project would reduce the complexities and interdependencies of the generators on the voltage limits of the Surowiec–South and Maine–New Hampshire interfaces. It could also increase the thermal and voltage limitations of the Surowiec–South and Maine–New Hampshire interfaces. This potential alternative is currently estimated to cost $4 million.

• **Upgrading 115 kV facilities near the southern Maine–New Hampshire border.** This could increase Maine–New Hampshire thermal transfer limits during peak load or shoulder-peak load periods. This potential alternative is estimated to cost approximately $4 million.

• **Adding capacitor banks in western Maine and at Maxcy's.** These additions could improve the Maine–New Hampshire voltage limits. This potential alternative is estimated to cost approximately $6 million.

The ISO must evaluate these alternatives to determine which one to implement for addressing southern New England's reliability needs. The system changes associated with closing the Y-138 line and addressing southern New Hampshire's needs will improve the interface capabilities of the area. Once the ISO evaluates the base reliability upgrades, it can evaluate the critical interface capabilities. It also can more fully assess the incremental needs and benefits of the various other alternatives and produce recommendations regarding the alternatives most beneficial to pursue.

The ISO expects to complete these tasks in late 2005.

Eliminating constraints and improving technical performance on this transmission corridor will become increasingly important as the demand for capacity and resource diversity in the region increases in the very near future. While current system conditions might not suggest a need for a major system reinforcement, this may change in time. Analyses performed to assess future transmission adequacy may indicate further reliability needs within Maine and New Hampshire that, in aggregate with the region's needs or independently, may require additional and more significant transmission system reinforcements.

These longer-term analyses will continue into 2006.

8.1.3 Northwest Vermont Reliability Project

The Northwest Vermont Reliability Project is designed to improve reliability of the northwestern area of Vermont. The project is particularly needed to cover outages in this area that could cause voltage collapse. The project consists of a new 36-mile, 345 kV line, a new 28-mile, 115 kV line, additional phase-angle regulating transformers (PARs), two dynamic voltage-control devices, and static compensation. Prior to 2005, the ISO and NEPOOL reviewed the proposed plan and completed the transmission-cost allocation (TCA) for the project, initially estimated to cost $156 million.

Two separate applications (Section 248) were filed with the Vermont Public Service Board (VPSB), one on May 23, 2003, for the Sandbar PAR, and a second one on June 5, 2003, for the balance of the project.[82] This was done to expedite the Sandbar work in light of the unexpected failure of the PAR at Plattsburgh, New York, on April 11, 2003 (35 months after a prior failure), which the Sandbar PAR is meant to replace. The VPSB approved the Sandbar PAR application, and construction was completed on this project in 2004. A modified version of the second application was approved in early 2005. VELCO is presently reviewing the modifications, which included, among other changes, modifications to the design of a portion of both the 345 kV line and the 115 kV line. The original scheduled in-service dates of 2005, 2006, and 2007 for the various phases of the project may not be achievable, and cost impacts could lead to an amended transmission-cost application.[83] Construction is now scheduled to begin in late 2005. If extreme weather conditions were to occur, combined with low generation availability and critical outages, local operator actions may be needed to maintain reliability.[84]

8.1.4 NSTAR 345 kV Transmission Reliability Project

The NSTAR 345 kV Project includes the construction of a Stoughton 345 kV station and the installation of three new underground 345 kV lines—two 17-mile cables to K Street Substation and one 11-mile cable to Hyde Park Substation. The project also includes adding new autotransformers at both Hyde Park and K Street Substations and shunt reactors at both Stoughton and K Street Substations. This $234 million project will be constructed in two stages with a final in-service date of late 2007.

This project brings a new source of 345 kV supply to the Boston area from the south to address the reliability problems that emerged due to changing load and generation patterns. In addition to improving the reliability of the Boston-area transmission system, it also will increase the Boston-import transfer capability by approximately 1,000 MW.

82 For information on Vermont Statute Section 248, see http://publicservice.vermont.gov/Lamoille/248statute.htm>.
83 See Vermont Public Service Board Docket No. 6860.
84 The loss of Highgate would compromise the reliability of the service to northern Vermont.

In July 2004, the ISO completed its review and approval of the proposed plan for this project. The Massachusetts Energy Facilities Siting Board issued its approval of this project to NSTAR in December 2004. Construction of Phase 1 of the project began in April 2005; it is scheduled for completion in June 2006.

8.1.5 Southwest Connecticut Reliability Project

As discussed in previous RTEP reports, the transmission system in SWCT must be upgraded to remove operating constraints on existing generation, allow new generation to be installed, and improve the import capability of the area. Studies of the Southwest Connecticut region have been ongoing for several years.

As reported in RTEP02, the Southwest Connecticut Reliability Project was to include a number of system reinforcements and an overhead (OH) 345 kV loop connecting existing 345 kV facilities in Middletown and Bethel. RTEP03 reconfirmed the need for the project in its entirety, but also indicated the likely need for some modifications due to local requirements. Ongoing studies have focused on alternative routings, alternative technologies, and significant technical performance issues raised by replacing sections of overhead line with underground cable.

In July 2003, the Connecticut Siting Council approved a combination overhead/underground (UG) alternative for the 20-mile Phase 1 project from Bethel to Norwalk. This modification required the development of a cost-effective acceptable design that could demonstrate the system would experience no significant adverse effects. The NEPOOL Reliability Committee found a number of relatively minor modifications to be necessary; it recommended approval of the proposed plan with the modifications in February 2004.

In April 2005, the CSC approved the construction of the approximately 70-mile Middletown to Norwalk section of the project (proposed and approved to include approximately 24 miles of UG cable). The addition of considerable high-capacitance cable into a relatively weak corner of the New England grid created the possibility for switching events to cause sustained temporary over-voltage conditions (due to harmonic resonances) that could significantly damage equipment.

After prolonged study, modifications were developed to mitigate the potentially harmful conditions and allow the project to continue. The modifications included changing the proposed cable technology and installing additional equipment and upgrades.

The current cost estimates for Phase 1 and Phase 2 of the SWCT Reliability Project are $357 million and $990 million, respectively. The ISO has reviewed and approved the proposed plan for Phase 1. Phase 1 substation construction is well underway, and work has begun on the 115 kV underground cable. Overall completion of the Phase 1 project still is scheduled for late 2006. Final supplementary studies to support the review of Phase 2’s proposed plan began in the second quarter of 2005.

Areas within the Greater SWCT Subarea and NOR Subarea also face reliability problems due to inadequate 115 kV transmission. The preferred upgrades are a pair of new 115 kV lines from Norwalk to Glenbrook, developed as part of the SWCT Reliability Project. Studies are currently determining whether the construction of the Singer Substation and the reconnection of the Bridgeport Energy Center generator, elements of the Phase 2 project, can advance independently of Phase 1 tasks without there being any adverse system impacts. If so, this could somewhat mitigate area short-circuit current problems from hampering the interconnection of some generation in the area.

8.1.6 Southern New England Reliability Analysis

The ISO continues to study the southern New England region to identify and resolve reliability issues and to determine whether any interdependencies exist among these issues. An overall goal of the study is to formulate a solution that better integrates load-serving and generating facilities within Massachusetts, Rhode Island, and Connecticut, enhancing the grid’s ability to move power from east to west and vice versa. Specific problems identified are as follows:

- The need for additional 345/115 kV-transformation capacity in Rhode Island
- Transmission constraints in Rhode Island, especially with transmission facilities out-of-service
- The inability of Rhode Island to access generation on the 345 kV system
- The criticality of the West Medway (MA) 345 kV station
- Forecasted capacity deficiencies in Connecticut

- Connecticut's limited import capability
- The limited effectiveness of the Lake Road plant to serve Connecticut load
- Connecticut's inadequate infrastructure to move power through the state
- The dependency of Connecticut import on Springfield–North Bloomfield capabilities
- Numerous contingency thermal overloads on the Springfield 115 kV system
- The dependency of the Springfield area on the Ludlow–Manchester–North Bloomfield 345 kV line

Ongoing studies are examining reinforcements for these key issues. The most practical alternatives to simultaneously improve the SEMA/RI, East-West, and Connecticut-import interface capabilities also appear to be 345 kV reinforcements. The studies to examine these alternatives are considering line loading, voltage, stability, and torsional-reclosing issues.

Different options for system reinforcement are being explored, based on available rights-of-way, space constraints at existing substations, and specific locations where area-supply reinforcements are needed.

As is typical, an overriding goal of the analyses is to determine the minimum set of projects that could provide the maximum benefits or solutions to the problems uncovered. The analyses could find some problems to be totally independent of the major issues facing the Greater Southern New England system that would, therefore, require an independent project. However, the studies may also indicate many issues could be remedied through a common project or group of projects.

Not all of the alternatives first formulated are still being considered because they have been deemed to be impractical or infeasible or due to their failure to sufficiently improve the transfer capability into Connecticut. The alternatives (in whole or in part) still being considered are listed below:

- Sherman Road or West Farnum (RI)–Lake Road (CT)–Card (CT) 345 kV
- Sherman Road or West Farnum–Kent County (RI)–Montville (CT) 345 kV
- Brayton Point (RI)–Montville 345 kV
- Millbury (MA)–Carpenter Hill (western MA)–Manchester (CT) 345 kV
- Millbury–Carpenter Hill–Ludlow–Agawam (western MA)–North Bloomfield (CT) 345 kV

Similarly, the options considered for improving load service into Rhode Island and to best integrate the generation connected to the 345 kV network include the following projects in whole or in part:

- Millbury–Sherman Road–Lake Road (CT)–Card (CT) 345 kV
- Millbury–West Farnum–Lake Road–Card 345 kV
- Millbury–West Farnum–Kent County–Montville 345 kV
- Brayton Point–Manchester Street (RI)–Kent County–Montville 345 kV
- 345/115 kV autotransformers at 345 kV substations in Rhode Island

The report of the study work is scheduled to be completed by the end of 2005, leading to an ISO-approval of a project plan by July 2006. The projected in-service date for the final set of solutions is 2011.

8.2 Transmission Improvements to Load/Generation Pockets

Various areas of the system are highly dependent on imbedded generators operating to maintain reliability in smaller areas of the system. Reliability may be threatened when few generating units are available to provide system support, considering normal levels of unplanned or scheduled outages of generators or transmission facilities. These generators have been designated as daily second-contingency units, which may be needed on a regular basis to maintain the reliable operation of these smaller areas to avoid violating ISO New England operating criteria. This could mean maintaining voltage at the minimum levels or avoiding overloads per OP 19. This local-area dependency on generating units typically results in relatively high net compensation period costs associated with out-of-merit unit commitments.

The ISO is studying many of these areas. Transmission projects are being planned for some areas, while others already have projects under construction to mitigate dependency on the imbedded generating units.

The sections that follow describe several of the smaller areas that have units for maintaining reliability and transmission projects for reducing the need to run these units.

8.2.1 Middletown Area

Four 115 kV lines and three generators connected to the 115 kV system—Middletown #2 (117 MW), Middletown #3 (236 MW), and Middletown #10 (17 MW)—supply the Middletown, Connecticut, area. Unit #10, 38 years old, is the newest of these units. Middletown #4 (400 MW) is connected to the 345 kV without transformation to the 115 kV system, so it does not support the local load in the area.

ISO Operations has flagged Middletown Units #2, #3, and #4 as daily second-contingency units that provide critical voltage support to the local 115 kV area. These units help avoid low voltages that would result from single- or double-circuit outages in the area. Since suppliers have not offered the electricity market alternative resources in this area to relieve the operation of these units, the ISO has studied alternative transmission solutions. The most effective solution for providing for future load growth, reducing dependency on the operation of these Middletown units, and potentially allowing the future retirement of the units was found to be a new 345/115 kV autotransformer located at Haddam Substation along with other area improvements. The ISO has reviewed and approved the proposed plan for these projects, which are discussed in more detail in Appendix C.

8.2.2 Norwalk-Stamford Area

The Norwalk–Stamford, Connecticut, area has been highly dependent on area generation to maintain reliable operation for general operation and maintenance of the 115 kV system. This area is part of the Greater SWCT area. This generation is comprised of Norwalk Harbor Units #1 (162 MW), #2 (172 MW), and #10 (17), and Cos Cob Units #10, #11, and #12 (18 MW each).

The two Norwalk Harbor units have been designated as daily second-contingency units for the current year. The planned SWCT 345 kV Reliability Project Phase 1 will provide for load growth, reduce dependency on the operation of these local units, and may eventually allow the retirement of these units.

8.2.3 Southwest Connecticut Area

For the current year, the ISO has designated 14 units in the SWCT area, excluding the Norwalk–Stamford area, for daily second contingency. These units are Bridgeport Energy, Bridgeport Harbor #2 and #3, Devon #11 to #14, Milford #1 and #2, and Wallingford #1 to #5. These units must operate due to the limitations of the transmission system in SWCT. The capacity deficiency in this area and the weakness of the existing transmission system have been the basis for the SWCT Reliability Project, Phase 2, which will help reduce the dependency on these units. Emergency measures, such as those included in the SWCT RFP for Emergency Capability Resources, can provide some relief during emergency OP 4 conditions until the Phase 2 project is built, but these are only temporary measures.[85] Phase 2 (along with Phase 1) will also allow the interconnection of new generation in this area. Other transmission solutions were examined in the process of deciding on the current 345 kV project.

8.2.4 Springfield Area

The Springfield area has two generators, West Springfield #3 and Berkshire Power, which have been designated as daily second contingency for the current year. Their operation is needed to support local reliability during peak hours for avoiding overloads in violation of OP 19. Electricity market suppliers have not proposed alternative resources in this area to relieve the operation of these units. Studies of alternative transmission solutions are underway for the Greater Springfield area. The ultimate solutions will provide for load growth and reduce dependency on the operation of these local units. They also may allow for the eventual retirement of the units.

8.2.5 Boston Area

The Boston area has several units designated as daily second contingency for the current year. New Boston #1 is needed for local reliability support for the Boston downtown area along with Mystic Units #7, #8, and #9. In the absence of any sufficient resource proposals from electric market suppliers for this area, the NSTAR 345 kV Reliability Project has been developed to serve future load growth and improve the reliability of this area. When completed, the project will allow New Boston Unit #1 to retire.

85 Resources were selected for SWCT in response to the RFP issued by ISO, December 1, 2003.

Exhibit SLH-3

NSTAR ELECTRIC

Boston Area Voltage Issues

Review of Recent and Planned NSTAR System Modifications and Changes to Boston Area Guide

3/1/05

C.P.Salamone

NSTAR ELECTRIC

Boston Area High Voltage Concerns

- Boston area has over 1000 MVAR of charging currents from area cable circuits plus charging from overhead lines
- Boston light load levels of 1800 MW at .96 PF places only 525 MVAR of reactive load on the system
- Absent reactive compensation voltages could exceed 1.07 per unit, risking equipment damage

NSTAR ELECTRIC

Boston Area Reactive Compensation

- OP17 Load Power Factor requirements are at .9 PF for light load conditions
- Seven 115 kV, 80 MVAR Reactors (560 MVAR) are in service in the Boston area
  - One reactor was out during Spring 2004 due to a disconnect switch failure
- Woburn LTC placed in service in Fall 2004
  - Helps 115 kV reactors lower 345 kV voltage
- While total generator leading reactive capability is 600 MVAR, units are typically not economic at light load

Boston Area Operation Procedures

- Prior Practices
  - Dispatch 115 kV reactors as needed
  - Switch out 345 kV cables as needed
    - Cable switching increased significantly in 2003
  - Dispatch generation based strictly on ranges of light load levels

- Revised Practice
  - Point system implemented to account for all reactive resources
    - Reactors
    - Woburn LTC
    - Generators
    - Cable openings
  - Total point req'ts defined for ranges of light load levels

Area planned/operated to sustain loss of most critical reactive resource (n-1). Cable switching relied on for n-2 contingency protection.

Boston Area Voltage Management

- Point system sets values for each reactive resource:
- ***Example*** Assignments
  - Each reactor 3 points,
  - LTC 2 pt,
  - Each generator 4 pt
  - Each cable 3 pt
- ***Example*** Case
  - Lowest overnight load level expected 10,500 for NE, 27 pts required
  - Mystic 8 on based on economic dispatch = 4 pt
  - All 115 kV reactors on = 21 pt
  - Woburn LTC available = 2 pt
  - Sandy Pond Exporting = 0 pt
  - Total points dispatched = 27 pt (meets requirements)

Impact of New Point System

- Assuming typical full availability of reactors and availability of the Woburn LTC, in general, one less unit will be required at light load levels.

- While some conditions may suggest possible area operation with no units, detailed System Planning study required first.

North Cambridge Reactor

- New 345 kV 160 MVAR Reactor due to be installed by May 2005
  - Directly controls 345 kV voltage
  - Variable compensation from 70 MVAR to 160 MVAR in 2.5 MVAR steps
  - Studies indicate that for 9,400 MW NE load level all generation could theoretically be off and voltages would be acceptable under normal and contingency conditions (assumes use of cable switching for contingencies)
  - Again, practical considerations of this operating condition are being studied further in System Planning studies