Thomas R. Teehan
Senior Counsel

August 7, 2012

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4323 - Application for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11
Responses to Navy Data Requests - Set 1 - ELEC

Dear Ms. Massaro:

Enclosed is an original and ten (10) copies of National Grid's[1] responses to the Navy's First Set of Data Requests in the above-captioned proceeding.

The responses to the First Set included with this filing are listed in the enclosed discovery log.

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

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 4323 Service List
Leo Wold, Esq.
Steve Scialabba, Division

[1] The Narragansett Electric Company d/b/a National Grid (herein referred to as "National Grid" or the "Company").

280 Melrose Street, Providence, RI 02907
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Certificate of Service

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

__/S/________________________ August 7, 2012
Janea Dunne Date

National Grid (NGrid) – Request for Change in Electric & Gas Distribution Rates
Docket No. 4323 – Service List updated on 6/22/12

Name/Address	E-mail Distribution	Phone
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Dr. Kay Davoodi, P.E. Utility Rates and Studies Office NAVFACHQ- Building 33 1322 Patterson Ave SE Washington Navy Yard, D.C. 20374-5065	Khojasteh.davoodi@navy.mil Larry.r.allen@navy.mil	202-685-3319
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Bruce Gay Monticello Consulting 4209 Buck Creek Court North Charleston, SC 29420	bruce@monticelloconsulting.com	
Matthew Kahal c/o Exeter Associates 10480 Little Patuxent Parkway Suite 300 Columbia, MD 21044	mkahal@exeterassociates.com	
File original & 11 copies w/: Luly E. Massaro, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Lmassaro@puc.state.ri.us Anault@puc.state.ri.us Adalessandro@puc.state.ri.us Nucci@puc.state.ri.us Dshah@puc.state.ri.us Sccamara@puc.state.ri.us	401-780-2107

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
DIVISION SET 1						
Division Set 1	Division 1-1-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 1-1-ELEC	
Division Set 1	Division 1-2-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 1-2-ELEC	
Division Set 1	Division 1-3-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 1-3-ELEC	
Division Set 1	Division 1-4-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 1-4-ELEC	
Division Set 1	Division 1-5-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 1	Division 1-6-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-6-ELEC	
Division Set 1	Division 1-7-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-8-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 1-8-ELEC	
Division Set 1	Division 1-9-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-9-ELEC	
Division Set 1	Division 1-10-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 1	Division 1-11-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-11-ELEC	
Division Set 1	Division 1-12-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-13-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-13-ELEC	
Division Set 1	Division 1-14-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-15-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-16-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-17-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-18-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-19-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-20-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 1	Division 1-21-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-21-ELEC	
Division Set 1	Division 1-22-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-23-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-23-ELEC	
Division Set 1	Division 1-24-ELEC	5/9/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 1	Division 1-25-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-26-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-27-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-27-ELEC	
Division Set 1	Division 1-28-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
Division Set 1	Division 1-29-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme	Att. DIV 1-29-ELEC	
Division Set 1	Division 1-30-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
Division Set 1	Division 1-31-ELEC	5/9/2012	**5/23/2012**	Michael D. Laflamme		
DIVISION SET 2						
Division Set 2	Division 2-1-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-1-GAS	
Division Set 2	Division 2-2-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-2-GAS	
Division Set 2	Division 2-3-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 2	Division 2-4-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-4-GAS	
Division Set 2	Division 2-5-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme		
Division Set 2	Division 2-6-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-6-GAS	
Division Set 2	Division 2-7-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-7-GAS	
Division Set 2	Division 2-8-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-8-GAS	
Division Set 2	Division 2-9-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-9-GAS	
Division Set 2	Division 2-10-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-11-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-12-GAS	5/14/2012	**5/25/2012**	Michael D. Laflamme	Att. DIV 2-12-GAS	
Division Set 2	Division 2-13-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-14-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-15-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-16-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme	Att. DIV 2-16-1-GAS Att. DIV 2-16-2-GAS Att. DIV 2-16-3-GAS	
Division Set 2	Division 2-17-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-18-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-19-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-20-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-21-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme	Att. DIV 2-21-GAS	
Division Set 2	Division 2-22-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme	Att. DIV 2-22-GAS	
Division Set 2	Division 2-23-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme	Att. DIV 2-23-GAS	
Division Set 2	Division 2-24-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		
Division Set 2	Division 2-25-GAS	5/14/2012	**5/29/2012**	Michael D. Laflamme		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
DIVISION SET 3						
Division Set 3	Division 3-1-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme	Att. DIV 3-1-ELEC/GAS	
Division Set 3	Division 3-2-ELEC/GAS	5/30/2012	**6/13/2012**	Michael D. Laflamme	Att. DIV 3-2-ELEC/GAS	
Division Set 3	Division 3-3-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert	Att. DIV 3-3-ELEC/GAS	
Division Set 3	Division 3-4-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-5-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert	Att. DIV 3-5-ELEC/GAS	
Division Set 3	Division 3-6-ELEC/GAS	5/30/2012	**6/13/2012**	Michael D. Laflamme	Att. DIV 3-6-ELEC/GAS (Redacted)	Att. DIV 3-6-ELEC/GAS (Confidential)
Division Set 3	Division 3-7-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme	Att. DIV 3-7-1-ELEC/GAS Att. DIV 3-7-2-ELEC/GAS Att. DIV 3-7-3-ELEC/GAS	
Division Set 3	Division 3-8-ELEC/GAS	5/30/2012	**6/12/2012**	Legal Department and Robert B. Hevert		
Division Set 3	Division 3-9-ELEC/GAS	5/30/2012	**6/11/2012**	Mustally Hussain	Att. DIV 3-9-1-ELEC/GAS Att. DIV 3-9-2-ELEC/GAS Att. DIV 3-9-3-ELEC/GAS Att. DIV 3-9-4-ELEC/GAS Att. DIV 3-9-5-ELEC/GAS Att. DIV 3-9-6-ELEC/GAS Att. DIV 3-9-7-ELEC/GAS Att. DIV 3-9-8-ELEC/GAS Att. DIV 3-9-9-ELEC/GAS	
Division Set 3	Division 3-10-ELEC/GAS	5/30/2012	**6/11/2012**	Mustally Husain	Att. DIV 3-10-ELEC/GAS	
Division Set 3	Division 3-11-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme	Att. DIV 3-11-ELEC/GAS	
Division Set 3	Division 3-12-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme		
Division Set 3	Division 3-13-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme		
Division Set 3	Division 3-14-ELEC/GAS	5/30/2012	**6/13/2012**	Michael D. Laflamme		
Division Set 3	Division 3-15-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme		
Division Set 3	Division 3-16-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme		
Division Set 3	Division 3-17-ELEC/GAS	5/30/2012	**6/11/2012**	Michael D. Laflamme	Att. DIV 3-17-ELEC/GAS	
Division Set 3	Division 3-18-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-19-ELEC	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-20-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-21-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-22-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert	Att. DIV 3-22-ELEC/GAS	
Division Set 3	Division 3-23-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert	Att. DIV 3-23-ELEC/GAS	
Division Set 3	Division 3-24-ELEC/GAS	5/30/2012	**6/13/2012**	Robert B. Hevert	Att. DIV 3-24-ELEC/GAS	
Division Set 3	Division 3-25-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert	Att. DIV 3-25-ELEC/GAS	
Division Set 3	Division 3-26-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		
Division Set 3	Division 3-27-ELEC/GAS	5/30/2012	**6/12/2012**	Robert B. Hevert		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
DIVISION SET 4						
Division Set 4	Division 4-1-GAS	6/7/2012	**6/29/2012**	Paul M. Normand	See Attached Page	See Attached Page
Division Set 4	Division 4-2-GAS	6/7/2012	**6/19/2012**	Paul M. Normand		
Division Set 4	Division 4-3-GAS	6/7/2012	**6/20/2012**	Ann E. Leary		
Division Set 4	Division 4-4-GAS	6/7/2012	**6/19/2012**	Paul M. Normand		
Division Set 4	Division 4-5-GAS	6/7/2012	**6/19/2012**	Paul M. Normand		
Division Set 4	Division 4-6-GAS	6/7/2012	**6/20/2012**	Ann E. Leary		
Division Set 4	Division 4-7-GAS	6/7/2012	**6/20/2012**	Ann E. Leary		
Division Set 4	Division 4-8-GAS	6/7/2012	**6/19/2012**	Ann E. Leary	Att. DIV 4-8-1-GAS Att. DIV 4-8-2-GAS Att. DIV 4-8-3-GAS Att. DIV 4-8-4-GAS Att. DIV 4-8-5-GAS	
Division Set 4	Division 4-9-GAS	6/7/2012	**6/20/2012**	Ann E. Leary		
Division Set 4	Division 4-10-GAS	6/7/2012	**6/19/2012**	Ann E. Leary	Att. DIV 4-10-GAS	
Division Set 4	Division 4-11-GAS	6/7/2012	**6/20/2012**	Ann E. Leary		
Division Set 4	Division 4-12-GAS	6/7/2012	**6/20/2012**	Ann E. Leary	Att. DIV 4-12-GAS	
Division Set 4	Division 4-13-GAS	6/7/2012	**6/19/2012**	Ann E. Leary and Michael D. Laflamme		
DIVISION SET 5						
Division Set 5	Division 5-1-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 5-1-ELEC	
Division Set 5	Division 5-2-ELEC	6/8/2012	**6/29/2012**	Evelyn M. Kaye	Att. DIV 5-2-1-ELEC Att. DIV 5-2-2-ELEC Att. DIV 5-2-3-ELEC	
Division Set 5	Division 5-3-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 5-3-1-ELEC Att. DIV 5-3-2-ELEC	
Division Set 5	Division 5-3-ELEC (Corrected)	6/8/2012	**7/2/2012**	Evelyn M. Kaye		
Division Set 5	Division 5-4-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye	Att. DIV 5-4-ELEC	
Division Set 5	Division 5-5-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye	Att. DIV 5-5-1-ELEC Att. DIV 5-5-2-ELEC	
Division Set 5	Division 5-6-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye	Att. DIV 5-6-1-ELEC Att. DIV 5-6-2-ELEC Att. DIV 5-6-3-ELEC	
Division Set 5	Division 5-7-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye		
Division Set 5	Division 5-8-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye		

Division Set 4

Division 4-1-GAS

ATTACHMENT	**CONFIDENTIAL ATTACHMENT**
1-18 Design Winter Sales RATE YEAR Rev 4-2-12.xls	
Att DIV 5-12 Meter Cost Detail MAC_B.xls	
Attach 1-2B(Test Year PLT ACCUMDEPR Acct) with Rate Year Adj 4-6.xls	
Attach 1-17 with Back-up (CY11_Charge_off (W Philibin 02 15 12)).xls	
Attach 1-24 (Services Inv Allocator) MAC.xls	
Attach 1-26 RATE YEAR (REG ACCNT 903000 CustRecordsColl Exp).xls	
Attach 1-27 RATE YEAR (ACCNT 908000 Cust Assistance Exp).xls	
Attach 1-29 with backup (6967 RI GAS SALES REPORT DEC11) MAC.xls	
Attachment to 1-11 (Rev Proof & Bill Detm)_A.xls	
Bill Impact-(2014 Base Rates and ISR for Rate Year template)_H AEL_1.xls	
NG RI Design Day Rate Year Rev 3-20-12 (LS).xls	
NG RI Gas Rate Design 4-16-12 B PMN - 7.xls	
Ngrid No 1-28 (Deposits) (3).docx	
RDA & ISR Adj by Rate Class.xls	
RI Gas Allocated COS 4-13-12 MAC.xlsx	
NGRI-GCOS Rate Year Revised 4-16-12 WITH ISR & RDA Revenues PRO.xls (REDACTED)	NGRI-GCOS Rate Year Revised 4-16-12 WITH ISR & RDA Revenues PRO.xls (CONFIDENTIAL)

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
Division Set 5	Division 5-9-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 5-9-ELEC	
Division Set 5	Division 5-10-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 5-10-1-ELEC Att. DIV 5-10-2-ELEC	
Division Set 5	Division 5-11-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 5-11-1-ELEC Att. DIV 5-11-2-ELEC Att. DIV 5-11-3-ELEC Att. DIV 5-11-4-ELEC	
Division Set 5	Division 5-12-ELEC	6/8/2012	**6/26/2012**	Evelyn M. Kaye		
Division Set 5	Division 5-13-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye		
Division Set 5	Division 5-14-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye	Att. DIV 5-14-ELEC	
Division Set 5	Division 5-15-ELEC	6/8/2012	**6/22/2012**	Evelyn M. Kaye	Att. DIV 5-15-ELEC	
Division Set 5	Division 5-16-ELEC	6/8/2012	**6/29/2012**	Evelyn M. Kaye	Att. DIV 5-16-1-ELEC Att. DIV 5-16-2-ELEC Att. DIV 5-16-3-ELEC Att. DIV 5-16-4-ELEC (REDACTED)	Att. DIV 5-16-2-ELEC Att. DIV 5-16-3-ELEC Att. DIV 5-16-4-ELEC (CONFIDENTIAL)
Division Set 5	Division 5-16-ELEC (Supplemental)	6/8/2012	**7/20/2012**	Evelyn M. Kaye	Att. DIV 5-16-1-ELEC Att. DIV 5-16-2-ELEC Att. DIV 5-16-3-ELEC Att. DIV 5-16-4-ELEC Supplemental (REDACTED)	Att. DIV 5-16-2-ELEC Att. DIV 5-16-3-ELEC Att. DIV 5-16-4-ELEC Supplemental (CONFIDENTIAL)
DIVISION SET 6						
Division Set 6	Division 6-1-GAS	6/8/2012	**7/2/2012**	Evelyn M. Kaye	Att. DIV 6-1-GAS	
Division Set 6	Division 6-2-GAS	6/8/2012	**7/2/2012**	Evelyn M. Kaye	Att. DIV 6-2-1-GAS Att. DIV 6-2-2-GAS	
Division Set 6	Division 6-2(d)-GAS (Supplemental)	6/8/2012	**7/20/2012**	Evelyn M. Kaye	Att. DIV 6-2(d)-GAS (Supplemental)	
Division Set 6	Division 6-3-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-3-GAS	
Division Set 6	Division 6-3-GAS (Supplemental)	6/8/2012	**7/20/2012**	Evelyn M. Kaye	Att. DIV 6-3-GAS (Supplemental)	
Division Set 6	Division 6-4-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-4-1-GAS Att. DIV 6-4-2-GAS	
Division Set 6	Division 6-5-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-5-GAS	
Division Set 6	Division 6-6-GAS	6/8/2012	**7/2/2012**	Evelyn M. Kaye	Att. DIV 6-6-1-GAS Att. DIV 6-6-2-GAS Att. DIV 6-6-3-GAS (REDACTED)	Att. DIV 6-6-2-GAS Att. DIV 6-6-3-GAS (CONFIDENTIAL)
Division Set 6	Division 6-7-GAS	6/8/2012	**6/22/2012**	Evelyn M. Kaye		
Division Set 6	Division 6-8-GAS	6/8/2012	**6/22/2012**	Evelyn M. Kaye		
Division Set 6	Division 6-9-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye		
Division Set 6	Division 6-9-GAS (Supplemental)	6/8/2012	**7/20/2012**	Evelyn M. Kaye	Att. DIV 6-9-GAS (Supplemental)	
Division Set 6	Division 6-10-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-10-1-GAS Att. DIV 6-10-2-GAS	
Division Set 6	Division 6-11-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye		
Division Set 6	Division 6-12-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye		
Division Set 6	Division 6-13-GAS	6/8/2012	**6/22/2012**	Evelyn M. Kaye		

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Division Set 6	Division 6-14-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-14-GAS	
Division Set 6	Division 6-15-GAS	6/8/2012	**6/26/2012**	Evelyn M. Kaye	Att. DIV 6-15-1-GAS Att. DIV 6-15-2-GAS Att. DIV 6-15-3-GAS	
Division Set 6	Division 6-16-GAS	6/8/2012	**7/2/2012**	Evelyn M. Kaye	Att. DIV 6-16-1-GAS Att. DIV 6-16-2-GAS Att. DIV 6-16-3-GAS Att. DIV 6-16-4-GAS Att. DIV 6-16-5-GAS (REDACTED)	Att. DIV 6-16-1-GAS Att. DIV 6-16-2-GAS Att. DIV 6-16-3-GAS Att. DIV 6-16-4-GAS Att. DIV 6-16-5-GAS (CONFIDENTIAL)
Division Set 6	Division 6-16-GAS (Supplemental)	6/8/2012	**7/23/2012**	Evelyn M. Kaye	Att. DIV 6-16-1-GAS Att. DIV 6-16-2-GAS Att. DIV 6-16-3-GAS Att. DIV 6-16-4-GAS Att. DIV 6-16-5-GAS Att. DIV 6-16-6-GAS Att. DIV 6-16-7-GAS Supplemental (REDACTED)	Att. DIV 6-16-1-GAS Att. DIV 6-16-2-GAS Att. DIV 6-16-3-GAS Att. DIV 6-16-4-GAS Att. DIV 6-16-5-GAS Supplemental (CONFIDENTIAL)
Division Set 6	Attachment Division 6-16-4-GAS (Supplemental) (Corrected)	6/8/2012	**8/7/2012**	Evelyn M. Kaye		Att. DIV 6-16-4-GAS (CONFIDENTIAL)
DIVISION SET 7						
Division Set 7	Division 7-1-GAS	6/12/2012	**7/5/2012**	Evelyn M. Kaye	Att. DIV 7-1-GAS	
Division Set 7	Division 7-2-ELEC	6/12/2012	**7/5/2012**	Evelyn M. Kaye	Att. DIV 7-2-GAS	
Division Set 7	Division 7-3-ELEC/GAS	6/12/2012	**7/5/2012**	Evelyn M. Kaye	Att. DIV 7-3-1-ELEC/GAS Att. DIV 7-3-2-ELEC/GAS Att. DIV 7-3-3-ELEC/GAS	
Division Set 7	Division 7-4-ELEC/GAS	6/12/2012	**7/5/2012**	Evelyn M. Kaye		
Division Set 7	Division 7-5-ELEC/GAS	6/12/2012	**6/28/2012**	Evelyn M. Kaye	Att. DIV 7-5-ELEC/GAS	
Division Set 7	Division 7-6-ELEC	6/12/2012	**6/25/2012**	Evelyn M. Kaye		
Division Set 7	Division 7-7-GAS	6/12/2012	**6/25/2012**	Evelyn M. Kaye		
Division Set 7	Division 7-8-ELEC/GAS	6/12/2012	**6/28/2012**	Evelyn M. Kaye		
DIVISION SET 8						
Division Set 8	Division 8-1-ELEC	6/14/2012	**6/25/2012**	Michael D. Laflamme	Att. DIV 8-1-ELEC	
Division Set 8	Division 8-2-ELEC	6/14/2012	**6/25/2012**	Michael D. Laflamme	Att. DIV 8-2-ELEC	
Division Set 8	Division 8-3-ELEC	6/14/2012	**7/3/2012**	Michael D. Laflamme	Att. DIV 8-3-ELEC	
Division Set 8	Division 8-4-ELEC	6/14/2012	**6/25/2012**	Michael D. Laflamme		
Division Set 8	Division 8-5-ELEC	6/14/2012	**7/5/2012**	Michael D. Laflamme	Att. DIV 8-5-ELEC	
Division Set 8	Division 8-6-ELEC	6/14/2012	**7/6/2012**	Michael D. Laflamme	Att. DIV 8-6-ELEC	
Division Set 8	Division 8-7-ELEC	6/14/2012	**7/12/2012**	Maureen P. Heaphy	Att. DIV 8-7-ELEC	
Division Set 8	Division 8-8-ELEC	6/14/2012	**6/25/2012**	Michael D. Laflamme		
Division Set 8	Division 8-9-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme		
Division Set 8	Division 8-10-ELEC	6/14/2012	**6/25/2012**	Michael D. Laflamme		
Division Set 8	Division 8-11-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme		
Division Set 8	Division 8-12-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme		
Division Set 8	Division 8-13-ELEC	6/14/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 8	Division 8-14-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme		
Division Set 8	Division 8-15-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme	Att. DIV 8-15-1-ELEC Att. DIV 8-15-2-ELEC	

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Division Set 8	Division 8-16-ELEC	6/14/2012	**6/27/2012**	Michael D. Laflamme	Att. DIV 8-16-ELEC	
DIVISION SET 9						
Division Set 9	Division 9-1-GAS	6/14/2012	**7/2/2012**	Michael D. Laflamme		
Division Set 9	Division 9-2-GAS	6/14/2012	**7/2/2012**	Michael D. Laflamme	Att. DIV 9-2-GAS	
Division Set 9	Division 9-3-GAS	6/14/2012	**6/27/2012**	Michael D. Laflamme		
Division Set 9	Division 9-4-GAS	6/14/2012	**6/27/2012**	Michael D. Laflamme & Susan L. Fleck		
Division Set 9	Division 9-5-GAS	6/14/2012	**6/27/2012**	A. Leo Silvestrini		
Division Set 9	Division 9-6-GAS	6/14/2012	**6/27/2012**	A. Leo Silvestrini	Att. DIV 9-6-GAS	
Division Set 9	Division 9-7-GAS	6/14/2012	**6/27/2012**	A. Leo Silvestrini		
Division Set 9	Division 9-8-GAS	6/14/2012	**6/27/2012**	A. Leo Silvestrini	Att. DIV 9-8-GAS	
Division Set 9	Division 9-9-GAS	6/14/2012	**6/27/2012**	A. Leo Silvestrini		
DIVISION SET 10						
Division Set 10	Division 10-1-ELEC	6/22/2012	**7/3/2012**	Howard S. Gorman	Att. DIV 10-1-1-ELEC Att. DIV 10-1-2-ELEC	
Division Set 10	Division 10-2-ELEC	6/22/2012	**7/3/2012**	Jeanne A. Lloyd	Att. DIV 10-2-1-ELEC Att. DIV 10-2-2-ELEC Att. DIV 10-2-3-ELEC Att. DIV 10-2-4-ELEC Att. DIV 10-2-5(1)-ELEC to Att. DIV 10-2-5(11)-ELEC Att. DIV 10-2-3-ELEC Att. DIV 10-2-4-ELEC Att. DIV 10-2-5-ELEC Att. DIV 10-2-6-ELEC Att. DIV 10-2-7-ELEC Att. DIV 10-2-8-ELEC Att. DIV 10-2-9-ELEC	
Division Set 10	Division 10-3-ELEC	6/22/2012	**7/5/2012**	Evelyn M. Kaye	Att. DIV 10-3-1-ELEC Att. DIV 10-3-2-ELEC	
Division Set 10	Division 10-4-ELEC	6/22/2012	**7/3/2012**	Alfred P. Morrissey	Att. DIV 10-4-ELEC	
Division Set 10	Division 10-5-ELEC	6/22/2012	**7/5/2012**	Howard S. Gorman	Att. DIV 10-5-ELEC	
Division Set 10	Division 10-6-ELEC	6/22/2012	**6/28/2012**	Howard S. Gorman		
Division Set 10	Division 10-7-ELEC	6/22/2012	**6/28/2012**	Howard S. Gorman	Att. DIV 10-7-ELEC	
Division Set 10	Division 10-8-ELEC	6/22/2012	**6/28/2012**	Howard S. Gorman		

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DIVISION SET 11						
Division Set 11	Division 11-1-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-1-1-ELEC/GAS Att. DIV 11-1-2-ELEC/GAS	
Division Set 11	Division 11-2-ELEC/GAS	6/25/2012	**7/6/2012**	Maureen P. Heaphy		
Division Set 11	Division 11-3-ELEC/GAS	6/25/2012	**7/6/2012**	Maureen P. Heaphy		
Division Set 11	Division 11-4-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-4-ELEC/GAS	
Division Set 11	Division 11-5-ELEC/GAS	6/25/2012	**7/10/2012**	Michael D. Laflamme		
Division Set 11	Division 11-6-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-6-1-ELEC/GAS Att. DIV 11-6-2-ELEC/GAS	
Division Set 11	Division 11-7-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-7-ELEC/GAS	
Division Set 11	Division 11-8-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-8-1-ELEC/GAS Att. DIV 11-8-2-ELEC/GAS Att. DIV 11-8-3-ELEC/GAS Att. DIV 11-8-4-ELEC/GAS Att. DIV 11-8-5-ELEC/GAS	
Division Set 11	Division 11-9-ELEC/GAS	6/25/2012	**7/12/2012**	Michael D. Laflamme	Att. DIV 11-9-ELEC/GAS	
Division Set 11	Division 11-10-ELEC/GAS	6/25/2012	**7/12/2012**	Michael D. Laflamme		
Division Set 11	Division 11-11-ELEC/GAS	6/25/2012	**7/10/2012**	Michael D. Laflamme	Att. DIV 11-11-ELEC/GAS	
Division Set 11	Division 11-12-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme	Att. DIV 11-12-ELEC/GAS	
Division Set 11	Division 11-13-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-14-ELEC/GAS	6/25/2012	**7/12/2012**	Michael D. Laflamme	Att. DIV 11-14-ELEC/GAS	
Division Set 11	Division 11-15-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-16-ELEC/GAS	6/25/2012	**7/10/2012**	Michael D. Laflamme		
Division Set 11	Division 11-17-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme		
Division Set 11	Division 11-18-ELEC/GAS	6/25/2012	**7/12/2012**	Michael D. Laflamme	Att. DIV 11-18-ELEC/GAS	
Division Set 11	Division 11-19-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme	Att. DIV 11-19-ELEC/GAS	
Division Set 11	Division 11-20-ELEC/GAS	6/25/2012	**7/12/2012**	Michael D. Laflamme	Att. DIV 11-20-ELEC/GAS	
Division Set 11	Division 11-21-ELEC/GAS	6/25/2012	**7/13/2012**	Michael D. Laflamme		
Division Set 11	Division 11-22-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-23-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-24-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-25-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		
Division Set 11	Division 11-26-ELEC/GAS	6/25/2012	**7/6/2012**	Michael D. Laflamme		

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DIVISION SET 12						
Division Set 12	Division 12-1-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini	Att. DIV 12-1-GAS	
Division Set 12	Division 12-2-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini	Att. DIV 12-2-GAS	
Division Set 12	Division 12-3-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini	Att. DIV 12-3-1-GAS Att. DIV 12-3-2-GAS	
Division Set 12	Division 12-4-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-5-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-6-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-7-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-8-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini	Att. DIV 12-8-GAS	
Division Set 12	Division 12-9-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-10-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini	Att. DIV 12-10-1-GAS Att. DIV 12-10-2-GAS Att. DIV 12-10-3-GAS	
Division Set 12	Division 12-11-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-12-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-13-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini	Att. DIV 12-13-GAS	
Division Set 12	Division 12-14-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-15-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-16-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-17-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini	Att. DIV 12-17-GAS	
Division Set 12	Division 12-18-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini	Att. DIV 12-18-GAS	
Division Set 12	Division 12-19-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-20-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-21-GAS	6/28/2012	**7/10/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-22-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-23-GAS	6/28/2012	**7/6/2012**	A. Leo Silvestrini	Att. DIV 12-23-1-GAS Att. DIV 12-23-2-GAS	
Division Set 12	Division 12-24-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini	Att. DIV 12-24-1-GAS Att. DIV 12-24-2-GAS Att. DIV 12-24-3-GAS	
Division Set 12	Division 12-25-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-26-GAS	6/28/2012	**7/13/2012**	A. Leo Silvestrini		
Division Set 12	Division 12-27-GAS	6/28/2012	**7/13/2012**	Ann E. Leary	Att. DIV 12-27-GAS	
Division Set 12	Division 12-28-GAS	6/28/2012	**7/13/2012**	Ann E. Leary	Att. DIV 12-28-GAS	
Division Set 12	Division 12-29-GAS	6/28/2012	**7/10/2012**	Ann E. Leary		
Division Set 12	Division 12-30-GAS	6/28/2012	**7/10/2012**	Ann E. Leary		

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DIVISION SET 13						
Division Set 13	Division 13-1-GAS	7/11/2012	**7/23/2012**	Paul M. Normand		
Division Set 13	Division 13-2-GAS	7/11/2012	**7/24/2012**	Paul M. Normand	Att. DIV 13-2-1-GAS Att. DIV 13-2-2-GAS Att. DIV 13-2-3-GAS Att. DIV 13-2-4-GAS Att. DIV 13-2-5-GAS Att. DIV 13-2-6-GAS Att. DIV 13-2-7-GAS	
Division Set 13	Division 13-3-GAS	7/11/2012	**7/23/2012**	Paul M. Normand		
Division Set 13	Division 13-4-GAS	7/11/2012	**7/23/2012**	Ann E. Leary	Att. DIV 13-4-GAS	
Division Set 13	Division 13-5-GAS	7/11/2012	**7/23/2012**	Paul M. Normand		
Division Set 13	Division 13-6-GAS	7/11/2012	**7/23/2012**	Ann E. Leary		
Division Set 13	Division 13-7-GAS	7/11/2012	**7/23/2012**	Ann E. Leary		
Division Set 13	Division 13-8-GAS	7/11/2012	**7/16/2012**	A. Leo Silvestrini		
Division Set 13	Division 13-9-GAS	7/11/2012	**7/17/2012**	A. Leo Silvestrini		
Division Set 13	Division 13-10-GAS	7/11/2012	**7/17/2012**	A. Leo Silvestrini		
Division Set 13	Division 13-11-GAS	7/11/2012	**7/17/2012**	A. Leo Silvestrini		
Division Set 13	Division 13-12-GAS	7/11/2012	**7/17/2012**	A. Leo Silvestrini		
Division Set 13	Division 13-13-GAS	7/11/2012	**7/17/2012**	A. Leo Silvestrini		
DIVISION SET 14						
Division Set 14	Division 14-1-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-2-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-3-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-4-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-5-GAS (Redacted)	7/11/2012	**7/24/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-5-GAS (Confidential)	7/11/2012	**7/24/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-6-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-7-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-8-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-9-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-10-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-11-GAS	7/11/2012	**7/23/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-12-GAS (Redacted)	7/11/2012	**7/24/2012**	Evelyn M. Kaye	Att. DIV 14-12-GAS	
Division Set 14	Division 14-12-GAS (Confidential)	7/11/2012	**7/24/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-13-GAS (Redacted)	7/11/2012	**7/24/2012**	Evelyn M. Kaye		
Division Set 14	Division 14-13-GAS (Confidential)	7/11/2012	**7/24/2012**	Evelyn M. Kaye		

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DIVISION SET 15						
Division Set 15	Division 15-1-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme	Att. DIV 15-1-ELEC	
Division Set 15	Division 15-2-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme		
Division Set 15	Division 15-3-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme	Att. DIV 15-13-ELEC	
Division Set 15	Division 15-4-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-5-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-6-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-7-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-8-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-9-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme		
Division Set 15	Division 15-10-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme		
Division Set 15	Division 15-11-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme		
Division Set 15	Division 15-12-ELEC	7/17/2012				
Division Set 15	Division 15-13-ELEC	7/17/2012	**7/24/2012**	Michael D. Laflamme	Att. DIV 15-13-ELEC	
Division Set 15	Division 15-14-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme		
Division Set 15	Division 15-15-ELEC	7/17/2012	**7/26/2012**	Michael D. Laflamme	Att. DIV 15-15-ELEC	
DIVISION SET 16						
Division Set 16	Division 16-1-GAS	7/17/2012	**7/26/2012**	Michael D. Laflamme	Att. DIV 16-1-GAS	
Division Set 16	Division 16-2-GAS	7/17/2012	**7/26/2012**	Michael D. Laflamme	Att. DIV 16-2-GAS	
Division Set 16	Division 16-3-GAS	7/17/2012	**7/26/2012**	Michael D. Laflamme		
Division Set 16	Division 16-4-GAS	7/17/2012	**7/31/2012**	Ann E. Leary	Att. DIV 16-4-GAS	
Division Set 16	Division 16-5-GAS	7/17/2012	**7/24/2012**	A. Leo Silvestrini	Att. DIV 16-5-GAS	
DIVISION SET 17						
Division Set 17	Division 17-1-ELEC	7/17/2012	**7/27/2012**	Howard S. Gorman		
Division Set 17	Division 17-2-ELEC	7/17/2012	**7/30/2012**	Alfred P. Morrissey and Jeanne A. Lloyd	Att. DIV 17-2-1-ELEC Att. DIV 17-2-2-ELEC Att. DIV 17-2-3-ELEC Att. DIV 17-2-4-ELEC	
Division Set 17	Division 17-3-ELEC	7/17/2012	**7/26/2012**	Howard S. Gorman		
Division Set 17	Division 17-4-ELEC	7/17/2012	**7/30/2012**	Jeanne A. Lloyd	Att. DIV 17-4-ELEC	
Division Set 17	Division 17-5-ELEC	7/17/2012	**7/26/2012**	Jeanne A. Lloyd		
DIVISION SET 18						
Division Set 18	Division 18-1-ELEC	7/20/2012	**7/26/2012**	Evelyn M. Kaye	Att. DIV 18-1-ELEC	
Division Set 18	Division 18-2-ELEC	7/20/2012	**7/26/2012**	Evelyn M. Kaye		
Division Set 18	Division 18-3-ELEC	7/20/2012	**7/27/2012**	Evelyn M. Kaye		
Division Set 18	Division 18-4-ELEC	7/20/2012	**8/2/2012**	Evelyn M. Kaye	Att. DIV 18-4-1-ELEC Att. DIV 18-4-2-ELEC Att. DIV 18-4-3-ELEC Att. DIV 18-4-4-ELEC Att. DIV 18-4-5-ELEC	
Division Set 18	Division 18-5-ELEC	7/20/2012	**7/30/2012**	Evelyn M. Kaye		
Division Set 18	Division 18-6-ELEC	7/20/2012	**8/2/2012**	Evelyn M. Kaye	Att. DIV 18-6-1-ELEC Att. DIV 18-6-2-ELEC Att. DIV 18-6-3-ELEC Att. DIV 18-6-4-ELEC	

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
DIVISION SET 19						
Division Set 19	Division 19-1-ELEC/GAS	7/25/2012				
Division Set 19	Division 19-2-ELEC/GAS	7/25/2012	**8/2/2012**	Michael D. Laflamme		
Division Set 19	Division 19-3-ELEC/GAS	7/25/2012	**8/2/2012**	Michael D. Laflamme		
Division Set 19	Division 19-4-ELEC/GAS	7/25/2012	**8/2/2012**	Michael D. Laflamme		
Division Set 19	Division 19-5-ELEC/GAS	7/25/2012	**8/2/2012**	Michael D. Laflamme		
Division Set 19	Division 19-6-ELEC/GAS	7/25/2012				
Division Set 19	Division 19-7-ELEC/GAS	7/25/2012	**7/30/2012**	Maureen P. Heaphy	Att. DIV 19-7-ELEC/GAS	
Division Set 19	Division 19-8-ELEC/GAS	7/25/2012	**7/30/2012**	Maureen P. Heaphy		
Division Set 19	Division 19-9-ELEC/GAS	7/25/2012				
DIVISION SET 20						
Division Set 20	Division 20-1-ELEC	7/27/2012				
Division Set 20	Division 20-2-ELEC	7/27/2012				
Division Set 20	Division 20-3-ELEC	7/27/2012				
DIVISION SET 21						
Division Set 21	Division 21-1-ELEC	8/1/2012	**8/7/2012**	Howard S. Gorman		
Division Set 21	Division 21-2-ELEC	8/1/2012				
Division Set 21	Division 21-3-ELEC	8/1/2012				
DIVISION SET 22						
Division Set 22	Division 22-1-GAS	8/3/2012				
Division Set 22	Division 22-2-GAS	8/3/2012				
Division Set 22	Division 22-3-GAS	8/3/2012	**8/7/2012**	Evelyn M. Kaye		
Division Set 22	Division 22-4-ELEC	8/3/2012				
Division Set 22	Division 22-5-GAS	8/3/2012				
Division Set 22	Division 22-6-GAS	8/3/2012				
Division Set 22	Division 22-7-GAS	8/3/2012				

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
COMMISSION SET 1						
Commission Set 1	Commission 1-1-ELEC/GAS	5/24/2012	**6/6/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-2-ELEC/GAS	5/24/2012	**6/7/2012**	Maureen P. Heaphy		
Commission Set 1	Commission 1-3-ELEC/GAS	5/24/2012	**6/7/2012**	Michael D. Laflamme	Att. COMM 1-3-1-ELEC/GAS Att. COMM 1-3-2-ELEC/GAS	
Commission Set 1	Commission 1-4-ELEC/GAS	5/24/2012	**6/7/2012**	Timothy D. Horan		
Commission Set 1	Commission 1-5-ELEC/GAS	5/24/2012	**6/6/2012**	Maureen P. Heaphy		
Commission Set 1	Commission 1-6-ELEC	5/24/2012	**6/7/2012**	Stephen F. Doucette and Maureen P. Heaphy		
Commission Set 1	Commission 1-7-ELEC	5/24/2012	**6/7/2012**	Stephen F. Doucette and Maureen P. Heaphy		
Commission Set 1	Commission 1-8-ELEC	5/24/2012	**6/6/2012**	Stephen F. Doucette		
Commission Set 1	Commission 1-9-ELEC	5/24/2012	**6/7/2012**	Stephen F. Doucette and Maureen P. Heaphy		
Commission Set 1	Commission 1-10-ELEC	5/24/2012	**6/6/2012**	Stephen F. Doucette		
Commission Set 1	Commission 1-11-ELEC	5/24/2012	**6/6/2012**	Stephen F. Doucette		
Commission Set 1	Commission 1-12-ELEC	5/24/2012	**6/6/2012**	Stephen F. Doucette		
Commission Set 1	Commission 1-13-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye		
Commission Set 1	Commission 1-14-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye		
Commission Set 1	Commission 1-15-ELEC/GAS	5/24/2012	**6/6/2012**	Evelyn M. Kaye		
Commission Set 1	Commission 1-16-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye and Michael D. Laflamme		
Commission Set 1	Commission 1-17-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye		
Commission Set 1	Commission 1-18-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye		
Commission Set 1	Commission 1-19-ELEC/GAS	5/24/2012	**6/4/2012**	Evelyn M. Kaye	Att. COMM 1-19-ELEC/GAS	
Commission Set 1	Commission 1-20-ELEC	5/24/2012	**6/6/2012**	Michael R. Hrycin	Att. COMM 1-20-1-ELEC Att. COMM 1-20-2-ELEC	
Commission Set 1	Commission 1-21-ELEC	5/24/2012	**6/6/2012**	Michael R. Hrycin	Att. COMM 1-21-ELEC	
Commission Set 1	Commission 1-22-ELEC	5/24/2012	**6/6/2012**	Michael R. Hrycin	Att. COMM 1-22-ELEC	
Commission Set 1	Commission 1-23-ELEC	5/24/2012	**6/7/2012**	Michael R. Hrycin		
Commission Set 1	Commission 1-24-ELEC	5/24/2012	**6/7/2012**	Michael R. Hrycin		
Commission Set 1	Commission 1-25-ELEC	5/24/2012	**6/6/2012**	Michael R. Hrycin		
Commission Set 1	Commission 1-26-ELEC	5/24/2012	**6/6/2012**	Michael R. Hrycin		
Commission Set 1	Commission 1-27-GAS	5/24/2012	**6/6/2012**	Jeffrey P. Martin		
Commission Set 1	Commission 1-28-GAS	5/24/2012	**6/6/2012**	Jeffrey P. Martin		
Commission Set 1	Commission 1-29-ELEC	5/24/2012	**6/4/2012**	Alfred P. Morrissey		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
Commission Set 1	Commission 1-30-ELEC	5/24/2012	**6/4/2012**	Alfred P. Morrissey		
Commission Set 1	Commission 1-31-ELEC	5/24/2012	**6/4/2012**	Alfred P. Morrissey		
Commission Set 1	Commission 1-32-ELEC	5/24/2012	**6/4/2012**	Alfred P. Morrissey		
Commission Set 1	Commission 1-33-ELEC	5/24/2012	**6/7/2012**	Alfred P. Morrissey		
Commission Set 1	Commission 1-34-ELEC	5/24/2012	**6/7/2012**	Alfred P. Morrissey		
Commission Set 1	Commission 1-35-ELEC/GAS	5/24/2012	**6/6/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-36-ELEC/GAS	5/24/2012	**6/7/2012**	Michael D. Laflamme	Att. COMM 1-36-ELEC/GAS	
Commission Set 1	Commission 1-37-GAS	5/24/2012	**6/7/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-38-ELEC	5/24/2012	**6/6/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-39-ELEC/GAS	5/24/2012	**6/7/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-40-ELEC/GAS	5/24/2012	**6/7/2012**	Ann E. Leary & Jeanne Lloyd	Att. COMM 1-40-ELEC/GAS	
Commission Set 1	Commission 1-41-ELEC/GAS	5/24/2012	**6/6/2012**	Robert B. Hevert		
Commission Set 1	Commission 1-42-ELEC/GAS	5/24/2012	**6/6/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-43-ELEC/GAS	5/24/2012	**6/6/2012**	Michael D. Laflamme		
Commission Set 1	Commission 1-44-ELEC/GAS	5/24/2012	**6/7/2012**	Maureen P. Heaphy	Att. COMM 1-44-ELEC/GAS	
Commission Set 1	Commission 1-45-ELEC/GAS	5/24/2012	**6/6/2012**	Stephen F. Doucette		
Commission Set 1	Commission 1-46-GAS	5/24/2012	**6/7/2012**	Ann E. Leary		
COMMISSION SET 2						
Commission Set 2	Commission 2-1-ELEC/GAS	7/10/2012	**7/24/2012**	Maureen P. Heaphy	Att. COMM 2-1-ELEC/GAS	
Commission Set 2	Commission 2-2-ELEC/GAS	7/10/2012	**7/19/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-3-ELEC/GAS	7/10/2012	**7/23/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-4-ELEC/GAS	7/10/2012	**7/23/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-5-ELEC/GAS	7/10/2012	**7/19/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-6-ELEC/GAS	7/10/2012	**7/24/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-7-ELEC/GAS	7/10/2012	**7/19/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-8-ELEC/GAS	7/10/2012	**7/24/2012**	Maureen P. Heaphy	Att. COMM 2-8-ELEC/GAS	
Commission Set 2	Commission 2-9-ELEC/GAS	7/10/2012	**7/20/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-10-ELEC/GAS	7/10/2012	**7/24/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-11-ELEC/GAS	7/10/2012	**7/19/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-12-ELEC/GAS	7/10/2012	**7/19/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-13-ELEC/GAS	7/10/2012	**7/20/2012**	Maureen P. Heaphy		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
Commission Set 2	Commission 2-14-ELEC/GAS	7/10/2012	**7/24/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-15-ELEC/GAS	7/10/2012	**7/31/2012**	Maureen P. Heaphy		
Commission Set 2	Commission 2-16-ELEC/GAS	7/10/2012	**7/30/2012**	Timothy D. Horan	Att. COMM 2-16-1-ELEC/GAS Att. COMM 2-16-2-ELEC/GAS	
Commission Set 2	Commission 2-17-ELEC/GAS	7/10/2012	**7/18/2012**	Robert B. Hevert		
Commission Set 2	Commission 2-18-ELEC/GAS	7/10/2012	**7/18/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-19-ELEC	7/10/2012	**7/16/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-20-GAS	7/10/2012	**7/19/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-21-ELEC/GAS	7/10/2012	**7/16/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-22-ELEC/GAS	7/10/2012	**7/26/2012**	Stephen F. Doucette		
Commission Set 2	Commission 2-23-ELEC/GAS	7/10/2012	**8/1/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-24-GAS	7/10/2012	**7/23/2012**	Ann E. Leary		
Commission Set 2	Commission 2-25-ELEC/GAS	7/10/2012	**7/23/2012**	Evelyn M. Kaye	Att. COMM 2-25-1-ELEC/GAS Att. COMM 2-25-2-ELEC/GAS	
Commission Set 2	Commission 2-26-ELEC/GAS	7/10/2012	**7/23/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-27-GAS	7/10/2012	**7/16/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-28-ELEC/GAS	7/10/2012	**7/16/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-29-ELEC/GAS	7/10/2012	**7/16/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-30-ELEC/GAS	7/10/2012	**7/16/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-31-ELEC	7/10/2012	**7/24/2012**	Evelyn M. Kaye	Att. COMM 2-31-ELEC/GAS	
Commission Set 2	Commission 2-32-GAS	7/10/2012	**7/23/2012**	Evelyn M. Kaye		
Commission Set 2	Commission 2-33-ELEC	7/10/2012	**7/20/2012**	Michael R. Hrycin		
Commission Set 2	Commission 2-34-ELEC	7/10/2012	**7/20/2012**	Michael R. Hrycin		
Commission Set 2	Commission 2-35-ELEC	7/10/2012	**7/27/2012**	Michael R. Hrycin	Att. COMM 2-35-1-ELEC Att. COMM 2-35-2-ELEC	
Commission Set 2	Commission 2-36-GAS	7/10/2012	**7/24/2012**	Jeffrey P. Martin		
Commission Set 2	Commission 2-37-ELEC/GAS	7/10/2012	**7/19/2012**	Jeffrey P. Martin		
Commission Set 2	Commission 2-38-ELEC	7/10/2012	**7/16/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-39-GAS	7/10/2012	**7/16/2012**	A. Leo Silvestrini		
Commission Set 2	Commission 2-40-ELEC/GAS	7/10/2012	**7/17/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-41-ELEC	7/10/2012	**7/17/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-42-ELEC/GAS	7/10/2012	**7/16/2012**	Michael D. Laflamme		

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
Commission Set 2	Commission 2-43-ELEC/GAS	7/10/2012	**7/24/2012**	Maureen P. Heaphy & Michael D. Laflamme	Att. COMM 2-43-ELEC/GAS	
Commission Set 2	Commission 2-44-ELEC/GAS	7/10/2012	**7/16/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-45-ELEC	7/10/2012	**7/20/2012**	Michael D. Laflamme	Att. COMM 2-45-ELEC	
Commission Set 2	Commission 2-46-ELEC	7/10/2012	**7/16/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-47-ELEC	7/10/2012	**7/20/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-48-ELEC	7/10/2012	**7/30/2012**	Michael D. Laflamme		
Commission Set 2	Commission 2-49-ELEC/GAS	7/10/2012	**7/18/2012**	Michael D. Laflamme	Att. DIV 2-49-ELEC/GAS	

DATA SET	DATA REQUEST	DATE ISSUED	DATE FILED	WITNESS	ATTACHMENT	CONFIDENTIAL ATTACHMENT
NAVY SET 1						
Navy Set 1	Navy 1-1-ELEC	7/27/2012				
Navy Set 1	Navy 1-2-ELEC	7/27/2012				
Navy Set 1	Navy 1-3-ELEC	7/27/2012				
Navy Set 1	Navy 1-4-ELEC	7/27/2012				
Navy Set 1	Navy 1-5-ELEC	7/27/2012				
Navy Set 1	Navy 1-6-ELEC	7/27/2012				
Navy Set 1	Navy 1-7-ELEC	7/27/2012				
Navy Set 1	Navy 1-8-ELEC	7/27/2012	**8/7/2012**	Jeanne A. Lloyd	Att. Navy 1-8-1-ELEC Att. Navy 1-8-2-ELEC Att. Navy 1-8-3-ELEC	
Navy Set 1	Navy 1-9-ELEC	7/27/2012	**8/7/2012**	Jeanne A. Lloyd		
Navy Set 1	Navy 1-10-ELEC	7/27/2012	**8/7/2012**	Howard S. Gorman		
Navy Set 1	Navy 1-11-ELEC	7/27/2012	**8/2/2012**	Howard S. Gorman		
Navy Set 1	Navy 1-12-ELEC	7/27/2012	**8/2/2012**	Howard S. Gorman		
Navy Set 1	Navy 1-13-ELEC	7/27/2012	**8/2/2012**	Howard S. Gorman		
Navy Set 1	Navy 1-14-ELEC	7/27/2012				

Navy 1-8-ELEC

Request:

Referring to the direct testimony of Company witness Jeanne Lloyd, page 8:

a) Please provide a detailed explanation of the Company's rationale for limiting the rate increase to the B/G-62, X-01 and Lighting classes to twice the system average rather than 1.5 times the system average;

b) Please provide a copy of any rate case precedent at the Rhode Island Public Utilities Commission that supports a gradualism standard of two times the system average rate increase.

Response:

a) The allocated cost of service study performed by Company Witness Howard S. Gorman and included in Schedule HSG-1 demonstrates that Rate Classes B/G-62, X-01 and Rates S-10/S14 are earning rates of return that are significantly below the system average rate of return. Therefore, a substantial increase in proposed rates for Rates B/G-62, X-01, S-10 and S-14 is required to ensure that these classes move closer to cost-based rates and that the cross-subsidies provided to these classes by other customers through the design of current rates are minimized. In determining the appropriate rate cap to apply to those classes that required the most substantial rate increases, the Company analyzed the total bill impacts resulting from the proposed rates for both the capped rate classes and the classes that are subsidizing the capped classes. The total bill impact for the average Rate G-62 customers resulting from an increase in distribution charges of 26.3 percent (two times the proposed system average increase) is approximately 4.5 percent and, as shown on Schedule JAL-6, total bill impacts for Rate G-62 customers at various usage levels range from of 3.8 percent to 6.7 percent. These total bill impacts are not significantly different than the bill impacts resulting from the proposed rates for the large Commercial and Industrial customers served on Rate G-32, and are comparable to the total bill impacts for the Residential Rate A-16 customers that range from 4.0 percent to 7.8 percent.

b) Attachment Navy 1-8-1-ELEC is a copy of the Commission's order in Docket Nos. 2290, 2290A, and 2290B (November 1995), a Narragansett Electric general rate case proceeding. In that order, the Commission approved the settlement agreement that had been proposed although it indicated on page 7 that "the Settlement Agreement shifted costs between rate classes and, based upon the Company allocated cost of service study, created the type of cross-subsidization that the Commission has attempted to eliminate in recent years". As shown on Attachment Navy 1-8-1-ELEC, Page 43 of 69, the final revenue allocation and rate increases resulted in two classes receiving increases that were two or more times the system average increase of 2.93 percent.

R.I.P.U.C. Order No. 13595 in R.I.P.U.C. Docket No. 1976 (April 1991) is attached as Attachment Navy 1-8-2-ELEC. In this Narragansett Electric general rate case proceeding, the Commission approved a settlement agreement that resulted in the rate class revenue allocations and increases shown on Page 16 of the order in that docket. As indicated, two of the classes, Rate Class V and Rate Class T, received rate increases approximately two or more times the system average increase.

Also attached as Attachment Navy 1-8-3-ELEC is Order No. 14039 in RI.P.U.C. Docket No. 2036 approving three separate settlement agreements in this Newport Electric Corporation general rate case. As indicated Page 60 of this attachment, the Commission states that "[i]n this docket the Company proposed to limit class rate increases to no more than two times the overall revenue increase granted. In Joint Exhibit 2, we see this limit continue as five classes, accounting for about 13% of total revenues, will see increases of 10.27% to 12.94%. We must consider the burden of rate shock to these classes if we were to make a more dramatic revenue shift as proposed by the Navy." Please note that, although the Navy was an intervenor in this proceeding, they did not support the rate design settlement that was approved by the Commission.

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

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: TARIFF FILING MADE BY THE NARRAGANSETT ELECTRIC COMPANY ON MARCH 1, 1995 : CONSOLIDATED DOCKET NOS. 2290, 2290A & 2290B

REPORT AND ORDER

On March 1, 1995, the Narragansett Electric Company (the "Company") filed an application with the Rhode Island Public Utilities Commission (the "Commission") seeking authorization for a 6.38% general rate increase in the amount of $30,516,000. On March 24, 1995 the Commission suspended the effective date of the rates for a period of five months beyond the proposed effective date of March 31, 1995.(Order No. 14669). On August 29, 1995, the Commission suspended the effectiveness of the proposed rates for an additional three months to December 1, 1995. (Order No. 14805)

In recent years the company has filed for the following rate increases:

Year Filed	Docket Number	Amount Requested	Amount Granted
1981	1591	$15,396,000	$ 9,386,000
1982	1659	$15,365,000	$ 6,245,000
1984	1719	$13,474,000	$(1,484,000)
1989	1938	$15,471,000	$ 5,790,000
1990	1976	$18,680,000	$13,000,000

The following appearances were entered in this proceeding:

FOR THE COMPANY: Thomas G. Robinson, Esquire
Craig L. Eaton, Esquire
David J. Saggau, Esquire

FOR THE DIVISION OF PUBLIC UTILITIES AND CARRIERS AND THE DEPARTMENT OF THE ATTORNEY GENERAL: Patricia French
Assistant Attorney General

FOR THE ENERGY COUNCIL OF RHODE ISLAND (TEC-RI)	Andrew J. Newman, Esquire
FOR THE CONSERVATION LAW FOUNDATION	Elizabeth Thagard
RHODE ISLAND LEGAL SERVICES	John Rao, Esquire
COALITION FOR CONSUMER JUSTICE	
DIRECT ACTION FOR RIGHTS AND EQUALITY	
PARENTS FOR PROGRESS	
FOR THE COMMISSION	Lindsay Johnson, Esquire

Description of the Company

The Narragansett Electric Company engages in the generation, transmission, and distribution of electricity, and serves approximately 323,000 customers located in 27 Rhode Island cities and towns. The Company is a wholly owned subsidiary of the New England Electric System ("NEES"), a registered public utility holding company incorporated in Massachusetts. Narragansett purchases substantially all of its energy requirements from the New England Power Company ("NEPCO"), NEES' wholesale generating and transmission subsidiary. The relationship between the Company and NEPCO is governed by an Integrated Facilities Agreement, executed and approved in 1967, by which Narragansett makes available to NEPCO its generating and transmission facilities. In return, NEPCO sells electricity to Narragansett to meet the needs of the Company's retail customers under a rate regulated by the Federal Energy Regulatory Commission ("FERC"). To the extent Narragansett provides power to NEPCO from its generating facilities, NEPCO reimburses the Narragansett for its generation and transmission expenses by way of a credit against Narragansett's purchased power bill.

The Company also receives and pays for various technical, engineering, and financial services which are provided by another NEES subsidiary, New England Power Service Company ("NEPSCO").

TRAVEL OF THE CASE

In support of its request for higher rates, the Company submitted pre-filed testimony of eight witnesses on March 1, 1995. The Company's President, Mr. Robert L. McCabe described the service territory and operations of the Company and explained its need for increased rates. (Narr. Ex. 1)

Ms. Lisa M. Fowler presented the derivation of the ongoing intrastate cost of service. (Narr. Ex. 2) The intrastate cost of service represents the total costs, including capital costs, incurred by the Company to provide service to end-use customers in Rhode Island. The difference between the cost of service and the revenues derived under the existing rate schedules represents the required rate increase.

Ms. Pamela A. Viapiano (Narr. Ex. 3) presented the allocation of costs between intrastate and interstate customers. More specifically, the costs of doing business are allocated between (1) the retail (end-users) customers in Rhode Island and (2) the wholesale customer, NEPCO, which purchases electricity for resale to other customers.

Ms. Ruth B. Langh (Narr. Ex. 4) presented the short term forecast of electricity sales. Ms. Langh's forecast is incorporated into Ms. Fowler's cost of services.

Mr. John G. Cochrane (Narr. Ex. 6) presented testimony on the Company's cost of capital, its external capital requirements and the impact of the Company's current earning capacity on its ability to issue long term debt. Mr. Cochrane also derived the overall cost of capital incorporated in Ms. Fowler's cost of service.

Dr. J. Peter Williamson presented an analysis of the cost of equity capital to the Company. (Narr. Ex. 7) His estimate was incorporated into the testimony of Mr. Cochrane and ultimately Ms. Fowler's cost of service analysis.

Ms. Roberta L. Laccetti presented the allocation of the intrastate cost of service to the Company's various rate classes and the allocation of the rate increase among such rate classes. (Narr. Ex. 8)

On March 1, 1995, the Company presented a motion for Authority to Implement Alternative Rate Proposal. In support of its motion, the Company presented the testimony of Mr. Lawrence J. Reilly in support of the Company's proposal to implement the rate increase in two steps occurring in June of 1995 and June of 1996. The Company's motion was denied by the Commission March 28, 1995.

On June 12, 1995, the Company filed testimony in support of a new revised tariff G-30 and a new tariff G-60. On June 26, 1995 the Company filed a new revised tariff G-30 and a new tariff G-60 and published notice of the changes in accordance with §39-3-11. (Narr. Ex. 8a) The filing was docketed as Docket 2290A and was consolidated with Docket 2290 by Order of the Commission on September 13, 1995. (Order 14807)

On June 29, 1995 the Division of Public Utilities and Carriers (the "Division") pre-filed the testimony of four witnesses. Mr. Matthew I. Kahal, Senior Economist at Exeter Associates, Inc. presented an analysis of the cost of equity capital to the Company. (Div. Ex. 4) Mr. Kahal's estimate of 10.75% was incorporated into the Division's proposed cost of service. Mr. Stephen L. Estomin, Senior Economist at Exeter Associates, presented testimony on the Company's revenue forecast. (Div. Ex. 3) Mr. Estomin proposed that the Company's revenue forecast be increased by the amount of $4,870,000 and his proposed adjustment was incorporated into the Division's proposed cost of service. Dr.

Charles E. Johnson presented testimony that the Company's proposed increase in depreciation rates be denied. (Div. Ex. 9) Finally, Mr. Michael L. Arndt presented the Division's proposed cost of service and proposed that the rate increase be limited to $11,389,000. (Div. Ex. 2)

On July 20, 1995 the Division and TEC-RI filed testimony on interclass cost allocation and rate design. Dr. Charles Johnson, the Division's witness presented a detailed critique of (1) the Division's interclass cost allocation, (2) a number of the proposed rates, and (3) the proposed changes to the Company's terms and conditions. (Div. Ex. 1) TEC-RI presented the testimony of Mark Drazen who addressed the proposed increase in the existing Auxiliary Service Rate and the need for a back-up service rate. (TEC-RI 1)

On August 4, 1995 the Company filed the rebuttal testimony of six witnesses. Mr. William R. Richer, Manager of the Financial Reporting Department of NEPCO, presented testimony rebutting the testimony of the Division's witness Arndt. (Narr. Ex. 9) Mr. William F. Dowd, Director of Compensation Benefits at NEPCO, presented testimony on the compensation provisions and health care plan changes instituted as part of collective bargaining negotiation completed in May, 1995. (Narr. Ex. 10) Ms. Langh presented testimony rebutting the testimony of the Division's witness Mr. Johnson on forecast sales. (Narr. Ex. 11) Mr. White presented testimony to rebut the testimony of the Division's witness Mr. Johnson on the Company's proposed depreciation rates. (Narr. Ex. 12) Mr. Williamson presented testimony to rebut the Division's testimony on rate of return. (Narr. Ex. 13) And finally, Ms. Laccetti presented testimony to rebut the testimony of Dr. Johnson's and Mr. Drazen on interclass cost allocation and rate design. (Narr. Ex. 14)

On September 6, 1995 each of the witnesses of the Division and TEC-RI filed surrebuttal testimony. (TEC-RI Ex.2, Div. Ex. 5-8)

On September 8, 1995 the Division, TEC-RI and the Company filed a proposed Settlement Agreement (Ex. Joint No. 1. attached) with the Commission resolving all issues between the Parties regarding the Company's revenue requirements in this Docket. The Agreement provided for a $17,800,000 increase in rates. The Agreement also provides for a return on equity of 11.0% and an overall return on the rate base of 9.24%. While the other parties did not enter into the Agreement, they were notified and did not oppose the Agreement. Hearings on the proposed Agreement were held on September 11, 1995.

On September 14, 1995 the Division, TEC-RI and the Company filed a proposed Settlement Agreement (Ex. Joint No. 2, attached) with the Commission resolving all issues between the Parties regarding all of the interclass cost allocation and rate design issues raised in this Docket. The Agreement allowed the Company to implement a charge for returned checks[1] and also lowered the interest rate paid on customer deposits[2]. Agreement p. 3 Accordingly, the Company recognized an additional $65,000 of revenues to be realized from returned check fees and $378,000 of savings in interest on customer deposits. Id. In addition, the rates were increased by $117,364 to recover lost revenues attributable to the Economic Development Discount. (Ex. RLL 14-M., Attachment 3). The net result was that the required rate increase was reduced to $17,474,000. Id. While the other parties did not enter into the Agreement, they were notified and did not oppose the Agreement. A hearing on the proposed Agreement was held on September 27, 1995.

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[1]. Under Paragraph 12 of the Company's Terms and Conditions a charge of fifteen dollars ($15.00) is imposed on a customer for each check presented for which there are insufficient funds to honor the check.
[2]. The interest rate pursuant to Paragraph 14 of the Terms and Conditions was lowered from twelve percent (12%) to the average rate over the prior calendar year for 10-year constant maturity Treasury Bonds as reported by the Federal Reserve Board.

THE COMMISSION'S REQUEST FOR MODIFICATION OF THE AGREEMENT

The Commission held open meetings on the Settlement Agreement on September 27, and October 6, 1995. The Commission was concerned about two aspects of the case. First, there was concern about the magnitude of the 2.93% rate increase which had been agreed upon by the Parties. (Narr. Ex. 18) Second, the Chairman was concerned that the Settlement Agreement shifted costs between rate classes and, based upon the Company's allocated cost of service study, created the type of cross-subsidization that the Commission has attempted to eliminate in recent years. The Chairman expressed surprise that TEC-RI had agreed to a settlement that created cross subsidies whereby industrial customers would subsidize residential customers. At the October 6, 1995 hearing the Commission voted to accept the Agreement if the Parties would agree to reduce the amount of the rate increase by approximately $3,000,000. The result reduced the impact of the increase and also decreased the amount of interclass cross-subsidization. On October 10, 1995 the Parties agreed to a reduced revenue increase of $14,910,000.

Pursuant to this agreement, a Supplemental Settlement on Revenue Requirement and Rate Design (Identified for the record by the Commission as Joint Ex. 4), supporting schedules and modified rates were filed with the Commission on October 11, 1995 and compliance rates were filed on October 16, 1995. (Compliance Filing, October 16, 1995 entered by agreement of the Parties on November 9, 1995 as Narr. Ex. 19, attached) Giving recognition to the additional income to be realized from sources other than base rates, as discussed above, the Company filed rates designed to produce revenues of $14,583,633. (Id. Schedule 1, Page 1 of 28) The increase was derived as follows:

Agreed upon Rate Increase	$14,910,000
Less:	
Reduced Int. Cust. Dep	378,000
Returned Check Charge	65,000
Add: Economic Dev. Discount	117,364
Increase in Base Rates	$14,584,364

RATE STRUCTURE CHANGES

The Settlement Agreement adopted a number of significant changes to the Company's rates and charges. The most significant changes are discussed below.

Credit to Promote Manufacturing

The most substantial rate structure change implemented is a revision to General Service Rates C, G, V, E-10, E-20, G-30 and G-60 to incorporate a Credit to Promote Manufacturing (CPM). (Narr. Ex. 8, p. 18) This provision grants to manufacturing customers a 5% discount on base rates, provided the customers account was not in arrears at the time the bill was issued. To qualify a customer must qualify for the exemption from the Rhode Island Gross Earning Tax. (Id.) The CPM shall terminate on the earlier of (1) two years after the date that it becomes effective, or (2) the effective date of any Rhode Island legislation which limits or alters the current exclusivity of the Company's franchise rights beyond those currently in effect on July 13, 1995. The Company estimated that the CPM would reduce customers' rates and the Company's revenues by approximately $1,957,000. Settlement on Cost Allocation and Rate Design Issues, Paragraph II.A.2 In other words, the revenue loss attributable to the CMP would not be allocated to the other customers and the economic loss would be absorbed by the Company.

New Rate G-60

The Company also proposed a new rate for large customers with a 12-month demand of 3,000 kw or more. This new G-60 rate is designed for high load factor customers and is a cost based rate based upon the Company's allocated cost of service study. The rate is expected to produce substantial saving for large customers billed under the rate. (Narr. Ex. 18, p. 4, RLL 8(u)) To the extent that any existing customer would save money by staying on rate G-30, those customers would be allowed to stay on the G-30 rate and the Company has agreed to absorb the revenue loss. The resulting revenue loss is estimated to be $1,092,000.

Because the Company has agreed to absorb the revenue loss associated with the CPM and the G-30 customers who do not transfer to Rate G-60, the rates allowed will not produce additional revenues $14,584,364. The rates will produce the following additional net revenues:

Agreed upon Rate Increase	$14,584,364
Less:	
Credit to promote manuf.	1,957,000
Rate G-60 Cust. on G-30	1,092,000
Net Revenue Increase	$11,535,364

NORMALIZATION OF BOOK/TAX DIFFERENCE ON COST OF REMOVAL

In its direct case the Company proposed to increase the depreciation rates used for book and rate setting purposes to recover the cost of removing plant from service at the end of its useful life. (Narr. Ex. 5) Under the proposal the Company would recover the cost of removal through depreciation rates before the actual cost of removal was incurred.

The Company would not realize any corresponding increase in its tax depreciation because, for tax purposes, the cost of removal can be taken as a tax deduction only when the cost of removal is actually incurred. Thus, the proposed change in depreciation rates would create a book/tax timing difference.

The Company sought to normalize the taxes (Narr. Ex. 2, pp. 18-22)or, more specifically, to "record a deferred tax on the difference between the amount of cost of removal reflected in book depreciation expense and the amount of cost of removal deducted for tax purposes" (Narr. Ex. 2, p. 21). In essence, under the proposal the Company would defer the tax liability and charge it into the future period in which the offsetting tax deduction for the cost of removal was actually taken.

In the Settlement Agreement the Parties agreed that the depreciation rates would not be increased at this time to recover cost of removal. The Parties agreed, however, to implement the normalization of taxes for the book/tax timing difference. The Commission objected to this normalization because there is no longer a book/tax timing difference to normalize. Accordingly, the Commission informed the Parties that it would approve the Settlement Agreement only if the tax normalization proposal were eliminated. This change reduced revenue requirements by approximately $2,890,000. The parties agreed to the change.

If the Company proposes to increase depreciation rates for cost of removal in its next rate case, the Commission would encourage the Company to again incorporate the normalization of the book/tax timing difference. It should, however, provide a broader analysis which shows how the taxes are being allocated and how the proposal will build up the appropriate deferred tax balance.

Accordingly, it is

(14857) ORDERED:

1. That the tariff filing made by the Narragansett Electric Company on March 1, 1995, is hereby rejected, denied and dismissed;

2. That the Settlement Agreement submitted by the Parties hereto, which allows for changes in the Terms and Conditions and base rates designed to produce additional revenues of approximately $14,583,633, for a total cost of service of $432,487,000 is hereby approved and adopted by the Commission, in toto;

3. That the tariffs filed by the Company on October 16, 1995 in compliance with the Supplemental Settlement on Revenue Requirement and Rate Design are hereby approved and the rate changes designed to produce additional revenues of $14,583,633 are hereby approved and adopted by the Commission to be applied to bills based upon meter readings taken thirty (30) days and after the date of this Order;

4. That the Narragansett Electric Company shall act in accordance

with all other findings and instructions contained in this report and order.

DATED AND EFFECTIVE AT PROVIDENCE, RHODE ISLAND, ON NOVEMBER 14 1995.

PUBLIC UTILITIES COMMISSION

James J. Malachowski, Chairman

Paul E. Hanaway, Commissioner

Kate F. Racine, Commissioner

INT EXHIBIT #1

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NARRAGANSETT ELECTRIC COMPANY REQUEST FOR RATE INCREASE	:	DOCKET 2290

SETTLEMENT ON REVENUE REQUIREMENT

I. INTRODUCTION

The Narragansett Electric Company ("Narragansett" or "Company"), the Energy Council of Rhode Island, and the Division of Public Utilities and Carriers ("Division") hereby stipulate and agree to the following resolution of the revenue requirement issues in the above-captioned proceeding.1/

II. BACKGROUND

On March 1, 1995, Narragansett filed with the Public Utilities Commission ("Commission") proposed tariffs and documentation designed to support its request for increased _pro forma_ revenues of $30,500,000. Since that date, the Division has undertaken to investigate all aspects of the Company's filing. Accordingly, in its initial pre-filed direct testimony, the Division posited that Narragansett's _pro forma_ rate year revenues

1/ The Conservation Law Foundation, Coalition for Consumer Justice, Direct Action for Rights and Equality and Parents for Progress, while not signatories to this agreement, stipulate that they are not opposed to its contents.

were deficient by $11,400,000. Subsequently, through various updates and changes, the Company's rebuttal position reduced its revenue request to $28,200,000. The Division's surrebuttal revised the Division's position on the Company's revenue deficiency upward to $15,200,000.

III. **STIPULATION AND SETTLEMENT**

The parties agree, in the interest of settling the instant rate proceeding, as follows.

A. Revenue Requirement, Generally

The parties agree that Narragansett shall file rates and tariffs pursuant to this Stipulation and Settlement which shall correct a rate year revenue deficiency of $17.8 Million. For purposes of illustration, the parties note that the resultant rate increase is $10,440,000 less than Narragansett's latest filed position, and $2,623,000 above the Division's latest filed position.

The parties further agree that, whether or not there is a later comprehensive settlement or a fully litigated outcome in this proceeding on the issue of rate design, Narragansett's revenue shall be approximately $3,000,000 per year less than the revenue requirement agreed to in this settlement assuming the Company's proposed discount to manufacturers and rate G-60 implementation plan are approved by the Commission.

The parties offer the following adjustments to reach the stipulated deficiency, for settlement purposes only:

1. Cost of Capital

In their filings, Narragansett requested an authorized return on equity of 12.0 percent; the Division recommended 10.75 percent. As part of this settlement, the Parties agree that Narragansett's equity return for AFDC calculations, earnings reports, and the cost of capital in this case shall be based on a return on equity of 11.0 percent. This represents a decrease of 0.5 percent from the currently authorized return on equity of 11.5%. The parties stipulate that the Company's capital structure is based upon Narragansett's actual capital structure as of June 30, 1995. (Attachment 1, p. 22) The overall rate of return on rate base shall be 9.24 percent.

2. Cost of Removal

In its initial filing, Narragansett included $2.6 Million of additional depreciation expense associated with the cost of removal for intrastate plant in its cost of service. That additional depreciation expense has been removed from the Settlement Cost of Service in Attachment 1, and the parties agree to resolve the appropriate level of depreciation expense associated with cost of removal in the context of the overall depreciation review discussed in Paragraph II below.

3. Deferred Taxes on Cost of Removal

As noted above, Narragansett's depreciation rates do not currently include an allowance for cost of removal. To date, Narragansett has flowed through to customers the current tax deduction related to its expenditures for cost of removal related to distribution and general plant, rather than normalizing these expenditures. As part of this settlement, the parties agree to normalize the cost of removal on a prospective basis for ratemaking purposes.

4. Storm Contingency Fund

In order to reach settlement, the parties stipulate that Narragansett's increased amortization of underfunding (as set forth in the Company's original filing) is removed. Narragansett instead will apply the net revenue proceeds from leases (other than those referenced in § 7 below) entered into by the Company for space in its transmission and distribution facitlities for the purpose of laying fiber optic cable. The parties intend Narragansett, for the purposes of reaching this settlement, to apply all cash receipts received from September 1, 1995 through December 31, 1996 (the "period"), including bonuses and other payments, for such leases which are in excess of the expenses actually incurred by Company for its part in the initial laying of fiber optic line on behalf of the lessees. Narragansett shall continue the annual accruals to the storm contingency fund at the preexisting level of $641,000 per year. Narragansett agrees to cooperate fully with the Division in an audit of past charges and accruals to the storm contingency fund, and in the development of additional guidelines, if appropriate, for these accruals and charges. Narragansett also agrees to file reports with the Division and the Commission which itemize and specifically describe the lessees, the space leased, and the gross and net proceeds attributable to fiber optic space leases at minimum on a quarterly basis throughout this period.

5. Municipal Taxes

The Company's rate year municipal tax recovery is decreased by $283,000.

6. Pension Expense

The settlement cost of service includes pension expense calculated using the methodology prescribed by FAS 87 based on FAS 87 expense booked in the test year. For the purposes of settlement only, the parties agree that no amortization of contributions in excess of FAS 87 expense is reflected in the settlement cost of service.

7. Amortization to Revenues from Certain 1995 Fiber Optic Leases

For the purposes of reaching settlement, revenues obtained by Narragansett, and calculated by the Company to be $3,995,000 (and this amount includes $150,000 which has been billed but not yet received from one of the lessees), from certain leases entered into by the Company for space in its transmission and distribution facilities for the purpose of laying fiber optic cable, shall be amortized to income over 24 months at a rate of approximately $167,000 per month, commencing on the effective date of the settlement rates. The parties believe and expect that this amortization reflects the total cash receipt amount of these contracts, inclusive of all bonuses and other payments, less the costs actually incurred by Company for its part in the laying of fiber optic line on behalf of the lessees.

8. Sales

In order to reach settlement, the Company's revenue deficiency and rate design are based on the kilowatthour sales recommended by the Division, but priced out per Narragansett's revenue model as set forth in its rebuttal exhibits. There has been no agreement on the appropriate method for future sales forecasts. This adjustment increases the Company's projected rate year revenues under present rates by $1,694,000 and reduces the revenue deficiency by that amount.

9. Settlement Credit

For the purposes of settlement, Narragansett agrees to a comprehensive additional reduction of $679,000 in compromise of miscellaneous contested issues.

IV. DEPRECIATION ISSUE

The parties agree to complete, by January 31, 1996, a review of the depreciation study filed by Narragansett in the rebuttal phase of this proceeding. If the parties reach agreement on the appropriate depreciation rates to be used for Narragansett, the parties agree that those rates may be submitted by Narragansett, without opposition by the Division, in Narragansett's next base rate proceeding.

V. MISCELLANEOUS PROVISIONS

A. Unless expressly stated herein, the making of this stipulation establishes no principles and shall not be deemed to foreclose any party from making any contention in any other proceeding or investigation.

B. Unless expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any rate proceeding for this Company or another.

C. This stipulation is the product of settlement negotiations. The content of those negotiations is privileged and all offers of settlement shall be without prejudice to the position of any party.

D. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

E. The Exhibits referenced in and attached to this Stipulation shall be deemed an integral part hereof. In the event that any inconsistency exists between the provisions of this stipulation and settlement and any of the Exhibits attached hereto, the provisions of this settlement shall supercede the provisions of any such Exhibits.

VI. CONCLUSION

WHEREFORE, the parties respectfully request the Commission approve this Stipulation to resolve all revenue requirement issues in Docket 2290.

DATED AT PROVIDENCE, this 8th day of September, 1995.

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS,

Patricia M. French, Esq.
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(401) 274-4400

NARRAGANSETT ELECTRIC COMPANY,

Thomas G. Robinson (CE)

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THE ENERGY COUNCIL OF RHODE ISLAND

Andrew Newman (CE)

Andrew Newman, Esq.
Rubin & Rudman
50 Rowes Wharf
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CERTIFICATION

I, Patricia M. French, hereby certify that I have, this 8th day of September, 1995, served a copy of the within Stipulation and Settlement on Revenue Requirement to each of the parties on the service list on file with the Clerk of the Public Utilities Commission.

Pat M French

SETTLEMENT COST OF SERVICE

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The Narragansett Electric Company

Intrastate Cost of Service
Rate Year 12/1/95 to 11/30/96
($000)

		5/ Total Company Per Books 7/1/93-6/30/94	Interstate and Other 1/ 7/1/93-6/30/94	Intrastate 7/1/93-6/30/94	Adjustment	5/ Intrastate Rate Year	Reference
1	Operation & Maintenance Expense	$67,585	$11,424	$56,161	2,789	58,950	Page 2
2	Conservation and Load Management Expense	10,509	10,509	0	0	0	-
3	Other Power Supply Expense	34	0	34	0	34	-
4	Donations	409	121	288	0	288	-
5	Fuel Expense	245	245	0	0	0	-
6	Depreciation Expense	21,900	6,767	15,133	2,106	17,239	Page 10
7	Gross Earnings Tax	19,220	0	19,220	(13,548)	5,672	Page 11
8	Municipal Taxes	14,044	1,794	12,250	978	13,228	Page 12
9	FICA	2,296	680	1,616	163	1,779	Page 13
10	Federal Unemployment	41	12	29	0	29	-
11	Federal Other - Environmental Tax	23	3	20 2/	0	20	-
12	State Unemployment	307	91	216	0	216	-
13	Current FIT	-	-	-	-	6,046	Page 14
14	Net Deferred FIT	671	(121) 8/	792	3,989	4,781	Page 15
15	Amort. of Investment Tax Credit	(508)	0	(508)	0	(508)	-
16	Amort. of Loss on Reacquired Debt 7/	841	81	760	3	763	-
17	Int. on Cust. Dep. (Cust. Dep. x 12%) 3/	666	0	666	53	719	-
18	Overall Return $352,284 x 9.24% 4/	-	-	-	-	32,551	-
19	Settlement Credit					(679)	
20	Total Cost of Service					$141,128	
21							
22							
23	Electric Energy Revenue 9/					$115,671 5/	
24	Other Revenues	5/ 5,444	0	5/ $5,444	$1,748 6/	7,658	-
25	Total Operating Revenue Rate Year					$123,329	
26							
27	Revenue Deficiency					$17,800	

1/ Exhibit PAV - 3(a), page1

2/ Intrastate Rate Base Allocation Factor (page 16) 86.75%

3/

	Rate Year	Less: Test year	Adjustment
Rate Year Customer Deposits (p. 19)	$5,991		
Interest @ 12.0%	$719	$666	$53

4/ See page 16.

5/ Expenses and revenues above exclude purchased power related costs and costs related to Post-Retirement Benefits Other than Pensions (PBOP's).

6/ Adjustment to increase pole attachment rentals in the rate year and to reflect amortization of $4 milion of fiber optic revenues over 24 months.

7/ Intrastate amortization of Loss on Reacquired Debt

Rate Year Total Company Amortization	$844
Intrastate Percentage	90.41%
Intrastate rate year Amortization of Loss on Debt	$763

8/ See page 15.

9/ Reflects correction of an overstatement of revenue from traffic signals of $466,000.

REMAINING PAGES OF ATTACHMENT 1
HAVE BEEN OMITTED

JOINT EXHIBIT #2

THE STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY PROPOSAL TO CHANGE RATE SCHEDULES	))))	DOCKET NO. 2290

Settlement on Cost Allocation and
Rate Design Issues

The Division of Public Utilities and Carriers (The "Division"), The Energy Council of Rhode Island ("TEC-RI"), and The Narragansett Electric Company ("Narragansett") together the "Parties") filed a Settlement Agreement with the Commission on September 8, 1995 resolving all issues between the Parties regarding the Company's revenue requirements in this Docket ("September 8 Settlement"). The Coalition for Consumer Justice, Direct Action for Rights and Equality, and Parents for Progress did not oppose the September 8 Settlement and do not oppose the Agreement reflected in today's settlement.

The September 8 Settlement expressly excluded rate design, cost allocation, and related issues. Since the September 8 Settlement, the Parties have engaged in further discussions regarding these unresolved issues, and the Parties have now agreed to a settlement of these issues which resolves all the outstanding issues in this Docket ("Settlement").

The Settlement is as follows:

I. Terms and Conditions

The revised terms and conditions and policies included in Attachment 1 to this Settlement are reasonable and should be approved. The revised terms and conditions and policies implement the following three changes:

A. Returned Check Fee

Revised term and condition paragraph 12 authorizes the Company to implement a returned check fee of $15 when a check is dishonored for insufficient funds after a second submission to a bank. This fee represents the recovery of Narragansett's actual costs incurred as a result of a dishonored check. The estimated proceeds from the returned check fee are credited to the allocated cost of service together with an adjustment for the Gross Earnings Tax, as discussed below. This will be used to reduce revenues required to be raised from tariffed rates.

B. Reduced Interest Rate on Customer Deposits

Revised term and condition paragraph 14 authorizes Narragansett to implement an interest rate on customer deposits equal to the rate paid on ten year, United States Treasury bonds for the preceding calendar year. This change reduces the level of interest expense on customer deposits included in the September 8 Settlement in this proceeding. These savings, adjusted for the Gross Earnings Tax, are credited to the allocated cost of service as discussed below and will reduce revenues required to be raised from tariffed rates. An interest rate of 12 percent is now required by the Commission in Order No. 10571 dated December 1, 1981, in Docket 1624, and to implement this change the parties request a waiver of that requirement.

C. Construction Advance Policy

Narragansett's Line Extension and Construction Advance Policy for Commercial and Industrial Customers shall be amended to allow customers to reduce the five year notice requirement available under the Service Agreement option to three years by repaying a ratable proportion of the construction advance that would have been required absent the customer's initial decision to sign the original Service Agreement.

II. Cost Allocation Study

The cost allocation for rate design purposes is included in Attachment 2. It contains the following adjustments:

A. Revenue Requirement Adjustments

The $17.8 million revenue deficiency included in the Settlement shall be adjusted as follows in the cost allocation study:

1. Reduction for Proceeds from Returned Check Fee

The revenue deficiency shall be reduced by $65,000 of other revenues received from the implementation of the returned check fee under paragraph I.A., above. (See Attachment 2, p. 14)

2. Savings in Interest on Customer Deposits

The revenue deficiency shall be reduced by $378,000 of savings in interest on customer deposits under Paragraph I.B., above. (See Attachment 2, p. 14)

B. Unrecovered Rate Discounts and Revenue Shortfalls

The cost allocation study in Attachment 2 does not include any recovery for the following elements:

1. Credit to Promote Manufacturing

Narragansett is authorized under paragraph III. C., below to implement a five percent discount from base rates for manufacturers. The revenue effect of this discount under the rates as initially filed in this case was projected to be $1,957,000 as shown on Attachment 3. This loss of revenue is not being recovered in Narragansett's rate design and is therefore being borne by Narragansett's shareholders.

2. G-60 Revenue Shortfall

Narragansett is authorized under Paragraph III. D., below to implement the G-60 rate with a limited one-time option for customers otherwise required to go on the G-60 rate to remain on the G-30 rate. The cost allocation study is based on the assumption that all customers eligible for the G-60 rate take service under the G-60 rate. The opt-out provision allows existing customers who would receive lower bills under the G-30 rate to remain on the G-30 rate. Narragansett projects that several customers may select the opt-out provision producing an estimated revenue shortfall of $1,092,000 below the revenues projected in Narragansett's cost allocation study under the rates as filed in this case. The revenue shortfall associated with this opt-out provision is not being recovered in

Narragansett's rate design and is therefore being borne by Narragansett's shareholders.

Together the adjustments, discounts, and shortfalls under this section reduce Narragansett's net revenue increase to customers by \$3,492,000 and reduces the net revenue increase received by the Company from \$17.8 million to \$14,308,000 million.

C. Cost Allocation Settlement

The cost allocation study in Attachment 2 includes settlement adjustments for the cost allocations among the rate classes. (See Attachment 2, Ex. RLL-14(a), page 1, line 11a). The settlement adjustment represents a compromise of the positions of the parties. Under this Settlement, no increase shall be allocated to rate A-65, and the increase allocated to the streetlighting class shall be limited to \$732,000 in the first year of the rates. Effective December 1, 1996, the street lighting rates shall be increased by an additional \$844,000 and proceeds from this second increase to the streetlighting class shall be credited to all customers in Narragansett's PPCA reconciliation, thereby reducing the amount of purchased power costs required to be collected from customers.

III. Rate Design

By September 18, 1995, Narragansett will file tariffs revised to collect the cost allocation shown in Attachment 2, which include the following modifications from the tariffs proposed by Narragansett in this case.

A. Auxiliary Service Rate

The changes proposed by Narragansett to the Auxiliary Service Rate are withdrawn, and the present Auxiliary Service Rate shall remain in effect.

B. Two Year Notice

The two year notice provision proposed by Narragansett for all general service rates is withdrawn, and the present notice provision shall remain in effect.

C. Credit to Promote Manufacturing

The Credit to Promote Manufacturing provisions proposed by Narragansett for inclusion in its general service rates as set forth on Attachment 4 shall be implemented.

D. G-60 Rate

The Parties agree that in order to avoid significant bill impacts associated with the establishment of the new G-60 rate class, existing customers currently taking service under Rate G-30 should be provided a one time option to stay on Rate G-30 even though they otherwise qualify for Rate G-60. Narragansett agrees to inform each affected customer of this opportunity and to provide billing analyses and other relevant information to assist customers in deciding whether to take advantage of this option, which will be available for 30 days after the new rates become effective.

E. Additional Issues

In addition, the following specific changes proposed by the Company are agreed to:

(I) The elimination of the hours use blocking and the increase in the customer charge for the G Rate;

(ii) The update of the water heater credit;

(iii) The rate design for the G-60 Rate with a nonseasonal demand charge and on-and off-peak energy prices; and

(iv) The increase in the customer and demand charges in the G-30 Rate.

IV. Miscellaneous Provisions

A. Unless expressly stated herein, the making of this Settlement establishes no principles and shall not be deemed to foreclose any party from making any contention in any other proceeding or investigation.

B. Unless expressly stated herein, the acceptance of this Settlement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any rate proceeding for this Company or another.

C. This Settlement is the product of settlement negotiations. The content of those negotiations is privileged and all offers of settlement shall be without prejudice to the position of any party.

D. This Settlement is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the Settlement in its entirety, the Settlement shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

E. The Attachments referenced in and attached to this Settlement shall be deemed an integral part hereof. In the event that any inconsistency exists between the provisions of this Settlement and any of the Attachments hereto, the provisions of this Settlement shall supersede the provisions of any such Attachments.

V. Conclusion

The parties respectfully request the Commission to approve this Settlement to resolve all cost allocation and rate design issues in Docket 2290.

Dated at Providence, this 14th day of September, 1995.

Respectfully submitted,

THE ENERGY COUNCIL OF
RHODE ISLAND

Andrew J. Newman, Esq.
Rubin and Rudman
50 Rowes Wharf
Boston, MA 02110

DIVISION OF PUBLIC UTILITIES
AND CARRIERS

Patricia M. French STS

Patricia M. French, Assistant Attorney General
Office of the Attorney General
72 Pine Street
Providence, RI 02903

THE NARRAGANSETT ELECTRIC COMPANY

Thomas G. Robinson CLE

Craig L. Eaton, Esq.
Thomas G. Robinson, Esq.
280 Melrose Street
Providence, RI 02907

provisions of this Settlement and any of the Attachments hereto, the provisions of this Settlement shall supersede the provisions of any such Attachments.

V. Conclusion

The parties respectfully request the Commission to approve this Settlement to resolve all cost allocation and rate design issues in Docket 2290.

Dated at Providence, this 14th day of September, 1995.

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THE NARRAGANSETT ELECTRIC COMPANY

Craig L. Eaton, Esq.
Thomas G. Robinson, Esq.
280 Melrose Street
Providence, RI 02907

ATTACHMENTS 1-4 HAVE BEEN OMITTED

JOINT EXHIBIT #4

THE STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY : DOCKET 2290
REQUEST FOR RATE INCREASE :

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PUBLIC UTILITIES COMMISSION

SUPPLEMENTAL SETTLEMENT ON REVENUE
REQUIREMENT AND RATE DESIGN

I. INTRODUCTION

On September 8, 1995, The Narragansett Electric Company ("Narragansett" or "Company"), the Energy Council of Rhode Island ("TEC-RI"), and the Division of Public Utilities and Carriers ("Division") filed a settlement agreement with the Commission resolving all issues between those parties regarding the Company's revenue requirement in this docket. On September 14, 1995, the Company, TEC-RI, and the Division filed a second settlement agreement with the Commission resolving all issues between those parties with respect to cost allocation, rate design, and related issues. While not signatories to either settlement, the Conservation Law Foundation, Coalition for Consumer Justice, Direct Action for Rights and Equality, and Parents for Progress stipulated that they were not opposed to the settlements.

The Commission held public hearings on the settlements filed on September 8 and September 14, on September 13 and 27, respectively. At an open meeting on October 6, 1995, the Commission voted to approve the settlement agreements submitted in this docket subject to the condition that the parties to those agreements agree to delete the provision in the settlement submitted on September 8, 1995, relating to the prospective adoption of tax normalization for cost of removal expenditures. This supplemental settlement agreement is intended to comply with the Commission's request.

II. COST OF REMOVAL

As noted in the Paragraphs III.A.2. and 3 of the settlement submitted on September 8, 1995, Narragansett's depreciation rates do not currently include an allowance for cost of removal. To date, Narragansett has flowed through to customers the current tax deduction related to its expenditures for cost of removal related to distribution and general plant, rather than normalizing these expenditures. As part of this supplemental settlement, Narragansett agrees to continue the current practice of flowing these tax deductions through to customers on a current basis. Paragraph III.A.3. of the settlement submitted on September 8, 1995, which would have allowed Narragansett to normalize cost of removal tax deductions on a prospective basis for ratemaking purposes, is therefore deleted and of no force and effect. This change reduces Narragansett's overall revenue requirement by $2,890,000.

A revised Settlement Cost of Service reflecting this change is included as Attachment 1 to this Agreement. Attachment 1 supports an overall revenue increase to the Company of $14,910,000 compared to the $17,800,000 increase originally agreed to by the parties.

III. RATE DESIGN

A. In the settlement agreement submitted on September 14, 1995, the parties agreed to an allocation among the Company's various rate classes of a net revenue increase of $17,473,633. As part of this Agreement, the parties agree that the $2,890,000 reduction in revenue requirement specified above shall be allocated among rate classes in proportion to allocated rate base, provided no decrease shall be allocated to the streetlighting rate class for which a rate moderation plan has been developed. As previously agreed, no increase shall be allocated to the A-65 rate class. These adjustments are specified on Attachment 2 to this Agreement.

B. The Company agrees to submit rate designs, typical bill calculations, and revised tariffs to implement the lower revenue increase agreed to herein by October 16, 1995.

IV. MISCELLANEOUS PROVISIONS

A. The parties stipulate to the admission of this Agreement, including all attachments, as a Full Exhibit in the record of this proceeding.

B. Except as specifically modified or superseded herein, the terms and conditions of the settlement agreements filed on September 8, 1995, and September 14, 1995, remain in full force and effect.

C. This Settlement establishes no principles and shall not be deemed to foreclose any party from making any contention in any future proceeding.

D. Other than as expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any subsequent rate proceeding.

E. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

V. CONCLUSION

The parties respectfully request that the Commission approve the agreements submitted on September 8 and 14, as modified by this agreement as the final resolution of all issues in Docket 2290.

Respectfully submitted,

The Division of Public Utilities and Carriers,

Patricia French (by SAS)

Patricia M. French, Esq.
Assistant Attorney General
72 Pine Street
Providence, RI 02903
(401) 274-4400

The Energy Council of Rhode Island

Andrew J. Newman / LOR

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(617) 330-7000

The Narragansett Electric Company

Thomas G. Robinson (CLE)

Craig L. Eaton, Esq.
Thomas G. Robinson, Esq
280 Melrose Street
Providence, RI 02907
(401) 874-7526

Dated: October 11, 1995

ATTACHMENT 1

SETTLEMENT COST OF SERVICE

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Range: PAGE1

The Narragansett Electric Company

Intrastate Cost of Service
Rate Year 12/1/95 to 11/30/96
($000)

		5/ Total Company Per Books 7/1/93-6/30/94	Interstate and Other 1/ 7/1/93-6/30/94	Intrastate 7/1/93-6/30/94	Adjustment	5/ Intrastate Rate Year	Reference
1	Operation & Maintenance Expense	$67,585	$11,424	$56,161	2,789	58,950	Page 2
2	Conservation and Load Management Expense	10,509	10,509	0	0	0	-
3	Other Power Supply Expense	34	0	34	0	34	-
4	Donations	409	121	288	0	288	-
5	Fuel Expense	245	245	0	0	0	-
6	Depreciation Expense	21,900	6,767	15,133	2,106	17,239	Page 10
7	Gross Earnings Tax	19,220	0	19,220	(13,663)	5,557	Page 11
8	Municipal Taxes	14,044	1,794	12,250	978	13,228	Page 12
9	FICA	2,296	680	1,616	163	1,779	Page 13
10	Federal Unemployment	41	12	29	0	29	-
11	Federal Other - Environmental Tax	23	3	20 2/	0	20	-
12	State Unemployment	307	91	216	0	216	-
13	Current FIT	-	-	-	-	5,064	Page 14
14	Net Deferred FIT	671	(121) 8/	792	2,117	2,909	Page 15
15	Amort. of Investment Tax Credit	(508)	0	(508)	0	(508)	-
16	Amort. of Loss on Reacquired Debt 7/	841	81	760	3	763	-
17	Int. on Cust. Dep. (Cust. Dep. x 12%) 3/	666	0	666	53	719	-
18	Overall Return $353,148 x 9.24% 4/		-	-	-	32,631	-
19	Settlement Credit					(679)	
20	Total Cost of Service					$138,239	
21							
22							
23	Electric Energy Revenue 9/	5/		5/		$115,671 5/	
24	Other Revenues	5,444	0	$5,444	$2,214 6/	7,658	-
25	Total Operating Revenue Rate Year					$123,329	
26							
27	Revenue Deficiency					$14,910	

1/ Exhibit PAV - 3(a), page1

2/ Intrastate Rate Base Allocation Factor (page 16) 86.75%

3/

	Rate Year	Less: Test year	Adjustment
Rate Year Customer Deposits (p. 19)	$5,991		
Interest @ 12.0%	$719	$666	$53

4/ See page 16.

5/ Expenses and revenues above exclude purchased power related costs and costs related to Post-Retirement Benefits Other than Pensions (PBOP's).

6/ Adjustment to increase pole attachment rentals in the rate year and to reflect amortization of $4 million of fiber optic revenues over 24 months.

7/ Intrastate amortization of Loss on Reacquired Debt

Rate Year Total Company Amortization	$844
Intrastate Percentage	90.41%
Intrastate rate year Amortization of Loss on Debt	$763

8/ See page 15.

9/ Reflects correction of an overstatement of revenue from traffic signals of $466,000.

REMAINING PAGES OF ATTACHMENT 1
HAVE BEEN OMITTED

ATTACHMENT 2

THE NARRAGANSETT ELECTRIC COMPANY
DOCKET NO. 2290
Calculation of Supplemental Settlement Increase

Rate	(1) Original Allocated Increase (after Credits)	(2) Allocated Rate Base	(3) New Reduction Allocated by Proportion of Rate Base	(4) Supplemental Settlement Increase (after Credits)	(5) Percent Increase
A-10	$8,653,906	$139,926,499	($1,222,307)	$7,431,599	4.55%
A-11	$2,240,667	$30,333,374	($264,973)	$1,975,694	5.08%
A-30	($68,133)	$1,810,414	($15,815)	($83,948)	-2.98%
A-65	$0			$0	0.00%
C-2	$3,872,477	$34,175,047	($298,531)	$3,573,946	8.33%
E-01	$4,748			$4,748	3.19%
E-10	$10,236			$10,236	3.05%
G	$569,984	$56,893,664	($496,986)	$72,998	0.09%
G-30	$1,751,683	$54,128,278	($472,829)	$1,278,854	1.11%
G-60	($485,448)	$11,157,344	($97,463)	($582,911)	-1.82%
St Ltg	$843,896			$843,896	10.47%
T	$2,995	$1,473,888	($12,875)	($9,880)	-0.39%
V	$76,276	$941,219	($8,222)	$68,054	5.03%
Contract	$346			$346	2.73%
Total	$17,473,633	$330,839,727	($2,890,000)	$14,583,633	2.93%

Notes:

(1) Page 2 of 3, Column 10 (Exhibit RLL-14(n))
(2) Allocated Cost of Service Study (Exhibit RLL-14(a), page 5) (excluding streetlights).
(3) (Column (2) / Sum of Column (2)) times $2,890,000 reduction
(4) Column (1) + Column (3)
(5) Column (4) as a percent of Page 2, Column (4)

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Attachment 2
Page 2 of 3

THE NARRAGANSETT ELECTRIC COMPANY
DOCKET NO. 2290
Reconciliation of Revenue Calculations

Rate	(1) Present Base Revenues	(2) KWh	(3) Factor Revenues @ $0.01809	(4) Total Present Revenues	(5) Allocated Increase (before Credits)	(6) Total Proposed Revenues (before Credits)	(7) Allocated Credits and Discounts	(8) Total Proposed Revenues (after Credits)	(9) Proposed Base Revenues (for Rate Design)	(10) Allocated Increase after Credits)
A-10	$138,040,301	1,401,139,561	$25,346,615	$163,386,916	$9,659,786	$173,046,702	($1,005,880)	$172,040,822	$146,694,207	$8,653,906
A-11	$32,104,567	375,483,442	$6,792,495	$38,897,062	$2,082,413	$40,979,475	$158,254	$41,137,729	$34,345,234	$2,240,667
A-30	$2,364,787	25,091,877	$453,912	$2,818,699	($77,579)	$2,741,120	$9,446	$2,750,566	$2,296,654	($68,133)
A-65	$4,761,982	61,572,528	$1,113,847	$5,875,829	$0	$5,875,829	$0	$5,875,829	$4,761,982	$0
C-2	$36,685,997	343,127,738	$6,207,181	$42,893,178	$3,694,181	$46,587,359	$178,296	$46,765,655	$40,558,474	$3,872,477
E-01	$112,513	2,005,115	$36,273	$148,786	$0	$148,786	$4,748	$153,534	$117,261	$4,748
E-10	$242,563	5,159,156	$93,329	$335,892	$0	$335,892	$10,236	$346,128	$252,799	$10,236
G	$70,145,152	794,238,996	$14,367,783	$84,512,935	$273,161	$84,786,096	$296,823	$85,082,919	$70,715,136	$569,984
G-30	$91,896,757	1,300,802,566	$23,531,518	$115,428,275	$1,469,287	$116,897,562	$282,396	$117,179,958	$93,648,440	$1,751,683
G-60	$24,945,909	394,054,198	$7,128,440	$32,074,349	($543,657)	$31,530,692	$58,209	$31,588,901	$24,460,461	($485,448)
St Ltg	$6,989,256	59,326,516	$1,073,217	$8,062,473	$732,008	$8,794,481	$111,888	$8,906,369	$7,833,152	$843,896
T	$2,048,318	25,559,514	$462,372	$2,510,690	($4,695)	$2,505,995	$7,690	$2,513,685	$2,051,313	$2,995
V	$1,146,789	11,386,433	$205,981	$1,352,770	$71,365	$1,424,135	$4,911	$1,429,046	$1,223,065	$76,276
Contrac	$8,370	238,890	$4,322	$12,692	$0	$12,692	$346	$13,038	$8,716	$346
Total	$411,493,261	4,799,186,530	$86,817,284	$498,310,545	$17,356,270	$515,666,815	$117,364	$515,784,178	$428,966,894	$17,473,633

Notes:

(1) = Forecasted Present Revenues (Settlement Filing, Attachment 4)
(2) = Forecasted kWh Sales (Settlement Filing, Attachment 4)
(3) = Column (2) x $0.01809/kWh (Fuel, PPCA, C&LM, FAS106, UCCA factors effective 7/1/95)
(4) = Column (1) + Column (3)
(5) = Summary of Total Rate Increases by Rate Class (Rate Design Settlement Agreement, Attachment 2, page 1 of 1)
(6) = Column (4) + Column (5) (per Rate Design Settlement Agreement)
(7) = See Page 3 (Column (7) - Column(5))
(8) = Column (6) + Column (7)
(9) = Column (8) - Column (3) (Proposed Design Revenues used in Settlement Filing, Schedule 1)
(10) = Column (9) - Column (1)

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NARRAGANSETT ELECTRIC COMPANY
Effect of Discounts on Rate Class Revenue Increases

	1	2	3	4	5	6	7
	Revenue Increase	E-10 E01,CON	A-65	Allocation of Economic Development	Economic Development	Total Adjustments	Adjusted Revenue Increase
A-10	$9,659,786	($6,089)	($1,046,407)	$46,616		($1,005,880)	$8,653,906
A-11	$2,082,413	($1,320)	$149,468	$10,106		$158,254	$2,240,667
A-30	($77,579)	($78)	$8,921	$603		$9,446	($68,133)
A-65						$0	$0
C-2	$3,694,181	($1,487)	$168,398	$11,385		$178,296	$3,872,477
E-01		$4,748				$4,748	$4,748
E-10		$10,236				$10,236	$10,236
G-00	$273,161	($2,476)	$280,345	$18,954		$296,823	$569,984
G-30	$1,469,287	($2,355)	$266,718	$18,033	($51,447)	$230,949	$1,700,236
G-60	($543,657)	($486)	$54,978	$3,717	($65,917)	($7,708)	($551,365)
T	($4,695)	($64)	$7,263	$491		$7,690	$2,995
V	$71,365	($41)	$4,638	$314		$4,911	$76,276
Street Lights	$732,008	($934)	$105,677	$7,145		$111,888	$843,896
Contracts		$346				$346	$346
	$17,356,270	$0	$0	$117,364	($117,364)	$0	$17,356,270

Notes:
(1) Rate Design Settlement Agreement, Attachment 2, page 1 of 1.
(2) Increase to E-10, E-01, and Contract Customers, allocated as a credit to other classes by Rate Base.
(3) Rate Design Settlement Agreement, Attachment 2, page 3 of 20, line (1) + line (2).
(4) Rate Design Settlement Agreement, Attachment 2, page 3 of 20, line (3).
(5) Rate Design Settlement Agreement, Attachment 2, page 3 of 20, line (7).
(6) Column (2) + Column (3) + Column (4) + Column (5)
(7) Column (1) + Column (6)

STATE OF ODE ISLAND AND PROVIDENCE NTATIONS
PUBLIC UTILITIES COMMISSION

Narragansett Electric Co.
General Rate Filing
Docket No. 2290

Final Procedural Schedule

03/01/95	Narragansett Electric filed new rate schedules
05/10	Deadline to file Motion to Intervene
06/29	Filing of Division's/Intervenor's prefiled testimony
08/04	Filing of Narragansett's rebuttal testimony
08/31	Filing of Division's/Intervenor's surrebuttal testimony
09/11-09/14* & 09/20-09/22	9:30 a.m. Cross-examination of all witnesses
10/10	Filing of briefs and a reconciliation explanation on the cost of service issues
10/20	Filing of reply briefs
11/30/95	Report and Order

Evening hearings:

08/03 @ 7:00 p.m. Burnside Memorial Bldg., Hope St. (Corner of Hope & Court St.)

08/17 @ 7:00 p.m. Public Utilities Commission, 100 Orange St., Providence, RI

09/07 @ 7:00 p.m. Council Chambers, Warwick City Hall, 3275 Post Rd., Warwick RI

*09/14 hearing date is reserved.

CC: PG Flynn
TG Robinson
LJ Reilly
MZ J
ADH
From: RGS

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY FLEX RATE

DOCKET NO. 2229

Report and Order

On August 11, 1994, the Narragansett Electric Company ("Narragansett" or "Company") filed with the Public Utilities Commission ("Commission") a proposed flexible time of use rate ("FLEX Rate"), designed to provide firm service through hourly energy prices reflecting Narragansett's marginal cost of service for purchased power. The tariff was suspended to allow the Division of Public Utilities and Carriers ("Division") adequate time to investigate the proposal.

The parties filed an Offer of Settlement on April 6, 1995.[1]

On April 12, 1995, following published notice, the Commission conducted a hearing on the filing at 100 Orange Street in Providence. The following appearances were entered:

FOR NARRAGANSETT:	David J. Saggau, Esq.
FOR THE DIVISION:	Patricia M. French, Esq. Assistant Attorney General
FOR THE COMMISSION:	Adrienne G. Southgate General Counsel

The Company called Peter T. Zschokke, manager of retail rates for the New England Power Service Company ("NEPSCo"), as its witness.[2] Mr. Zschokke testified that, under the

[1] This document is attached and incorporated by reference as Appendix A.
[2] The prefiled testimony, admitted as Narragansett Ex. 1, was submitted by Tina M. Bennett of the NEPSCo Rate Department. Ms. Bennett has accepted a new position. Mr. Zschokke adopted her prefiled testimony as his own.

Offer of Settlement, the proposed G-50 rate would be offered for a period of time from Commission approval through December 31, 1997. The settlement made a number of changes to the proposed tariff to incorporate suggestions made by the Division and its consultant, Dr. Johnson.[3]

The FLEX Rate allocated New England Power Company demand charges to each hour, based upon a probability of peak basis. There are four schedules in each season, allowing more accurate delineation of the actual costs of serving customers during any given day. The rate was described as an experiment in which no more than twenty customers take service under the proposed G-50 rate.[4]

The settlement contemplates that the Company will file a report on or before April 1, 1997, reporting the experience to date on real time pricing and proposing what should be done after the experimental rate expires on December 31, 1997.

Mr. Zschokke described the customer access charge, which is designed into the Flex Rate to permit customers to pay the same amount which would have been assessed under Rate G-30. There would be no immediate loss of contribution from these customers. If the customers respond to the FLEX Rate price signals by consuming more electricity during lower-priced hours, and/or by consuming less during higher-priced hours, then they can save money relative to the G-30 rates.

The G-50 customer who cannot shift load in response to the price signals has some protection under the tariff: rates are capped at 110% of the G-30 rate. Any overage will be

---

[3] Dr. Johnson's prefiled testimony was admitted as Division Ex. 1.
[4] In Massachusetts, where the FLEX Rate has been in effect since October, only two customers have elected to take service under the rate. The witness indicated that approximately 200 G-30 customers would be eligible for the G-50 rate.

borne by Narragansett until the next general rate filing. Mr. Zschokke stated that, in his experience, customers who elect the Flex Rate do so because they know they can benefit.

Customers who increase their loads over the base year demand level will have to pay a distribution expansion charge, which is estimated to equal the marginal cost for Narragansett's distribution facility of $2.37 per kW. Customers who merely shift loads will not incur this charge.

Mr. Zschokke gave his opinion that the FLEX Rate is not inimical to emerging competition in the electric market. In fact, he stated, service under the G-50 rate develops the mechanisms at the customer's location that are required for competition.

The Commission conducted an open meeting to discuss the Offer of Settlement and the testimony, and concluded that FLEX Rate, as modified by the settlement, is just and reasonable, and in the ratepayers' best interests.

Accordingly, it is

(14720) ORDERED:

The Narragansett Electric Company's FLEX Rate is hereby approved, as modified by the Offer of Settlement.

EFFECTIVE AT PROVIDENCE, RHODE ISLAND ON APRIL 14, 1995, PURSUANT TO AN OPEN MEETING DECISION. WRITTEN ORDER ISSUED MAY 5, 1995.

PUBLIC UTILITIES COMMISSION

James J. Malachowski, Chairman

Paul E. Hanaway, Commissioner

Kate F. Racine, Commissioner

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

The Narragansett Electric Company **FLEX Rate**	)	**Docket No. 2229**

OFFER OF SETTLEMENT

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

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The Narragansett Electric Company)
FLEX Rate) Docket No. 2229

OFFER OF SETTLEMENT

This Offer of Settlement is jointly submitted by the Division of Public Utilities and Carriers ("Division") and The Narragansett Electric Company ("NECO"), together hereinafter the "Parties," and resolves all issues between the Parties in this proceeding regarding NECO's proposed flexible time of use rate.

I. Background

On August 11, 1994, NECO filed a proposed flexible time of use rate (FLEX Rate) which is designed to provide firm service through hourly energy prices reflecting NECO's marginal cost of service for purchased power. On September 20, 1994, the Commission suspended the rate for five months beyond the proposed October 1, 1994 effective date, and on February 14, 1994, suspended the rate for an additional three months.

Pursuant to the procedural schedule originally approved by the Commission, the Parties have completed discovery. On March 8, 1995, prefiled testimony of Dr. Charles Johnson was submitted on behalf of the Division. That testimony raised certain concerns about the FLEX Rate as proposed by the Company. On Thursday, March 30, 1995, the Parties held a settlement conference pursuant to a revised procedural schedule approved by the Commission. After a discussion of NECO's proposal and a review of the record, the Parties have agreed to the following proposal as a full resolution of all issues between them in this proceeding.

II. Agreement

The Parties agree that NECO's proposed Flex Rate be approved as originally filed subject to the modifications and conditions described below and as reflected in the revised tariff sheets attached hereto:

1. The FLEX Rate shall be approved and available to customers through December 31, 1997, on an experimental basis.
2. On or before April 1, 1997, NECO shall file a proposal with the Commission to either make the FLEX Rate permanent, or to modify or eliminate the rate, based on the experience achieved with the experimental FLEX Rate. The proposal shall address the Division's concerns about the cost of incremental usage being lower under the FLEX Rate than under the otherwise applicable G-30 rate.
3. Through December 31, 1997 the rate shall be limited to twenty (20) customers on a first-come first-served basis.
4. New customers or customers with insufficient load data shall be eligible for the rate using an estimated base usage level to be established by NECO. The estimated base usage level shall be set at the expected actual usage level.

III. Miscellaneous Provisions

1) Other than as expressly stated herein, this Offer of Settlement establishes no principles and shall not be deemed to foreclose either Party from making any contention in any future proceeding or investigation.
2) Other than as expressly stated herein, the approval of this Offer of Settlement by the Commission shall not in any respect constitute a determination as to the merits

of any issue in any other proceeding.

3) This Offer of Settlement is the product of settlement negotiations. All offers of settlement shall be without prejudice to the position of either Party presenting such offer.

4) This Offer of Settlement is submitted on the condition that it be approved in full by the Commission and on further condition that if the Commission does not approve this Offer of Settlement in its entirety, this Settlement shall be deemed withdrawn and shall not constitute a part of the record in this or any other proceeding or be used for any purpose unless any changes or unauthorized usage of the Settlement is expressly agreed to by the Parties.

The Parties respectfully request the Commission to adopt this Offer of Settlement as a final resolution of all issues in this proceeding.

Dated this 6th day of April, 1995.

Respectfully submitted:

THE NARRAGANSETT ELECTRIC COMPANY

By: David Saggau
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DIVISION OF PUBLIC UTILITIES AND CARRIERS

By: Patricia M. French (STS)
Patricia M. French
Assistant Attorney General
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Revisions to the Originally Filed G-50 Tariff

1. Inserted language into the Availability section for conformance with the G-30 tariff. The inserted language states that all service at a given location shall be furnished under this tariff.
2. Amended the PPCA cover sheet for changes in adjustment factors.
3. Added language in the section Definition of Holidays to note that all holidays are the date of national observance.
4. Added language to specify the number of times each price schedule would be called in each season.
5. Removed language for the Oil Conservation Adjustment.
6. Added Gross Earnings Tax Credit for Manufacturers.
7. Removed redundant notice language in the section entitled "Terms of Agreement." Notice requirements are given under the availability clause.
8. The prices are updated to reflect NEP's W-95(s) Tail Block Demand and Energy charges. Thus, the tariff reflects the latest approved estimate of long-run marginal energy costs.
9. NEP's tail block demand charges are allocated to each hour with a 5 year history of probabilities of peak instead of the one year history in the original filing. This change should stabilize the hourly rates over time.
10. Removed any demand allocation from weekends and holidays price schedules since actual peaks have never occurred during those periods. This change improves the price signal to customers.
11. Adjusted the hourly energy prices for the Gross Earnings Tax.
12. Re-structured the detail price schedule pages to allow a customer to view all prices in a given season on one page.
13. Revised the detail hourly price schedules for better comprehension by the customer.

THE NARRAGANSETT ELECTRIC COMPANY

Business Service - Flexible Time-of-Use (G-50) R.I P.U.C. .P.U.C. No. 1009 Adjusted by:	Effective May 1, 1995
Purchased Power Cost Adjustment W-95(S)	February 10, 1995

Monthly Charge As Adjusted

Customer Charge: Set forth in the Service Agreement

Demand Charge: $2.37 per kW times the Distribution Expansion Demand

Energy Charge: The hourly kWh cost as shown in the hourly kWh prices in Attachment 1 of the rate will be adjusted by the following:

Plus .007¢ per kWh for Uniform Conservation Cost Adjustment (Eff. Jan. 1, 1995).

Plus .233¢ per kWh for Conservation and Load Management Adjustment (Eff. Jan. 1, 1995).

Plus .097¢ per kWh for Phase-in of FAS 106 (Eff. January 1, 1995).

Plus .138¢ per kWh for PPCA Reconciliation Adjustment Factor (Eff. February 10, 1995).

Other Rate Clauses apply as usual.

THE NARRAGANSETT ELECTRIC COMPANY

BUSINESS SERVICE - FLEXIBLE TIME-OF-USE PRICING (G-50)

AVAILABILITY

This rate is an experimental rate that is available only to a limited number of customers that will be selected by the Company from customers whose maximum billing demand exceed 500 kW and who would otherwise take service under the G-30 rate. Customers taking service under this rate must sign a service agreement.

Service under this rate is available for a term of 1 year. On or before the anniversary of beginning service under this rate, the Company and the customer will mutually determine whether service under this rate will continue beyond the one year term. In any event, the Company has the right to terminate the rate by moving customers back to the G-30 rate after two years of service under this rate.

If any electricity is delivered hereunder at a given location, then all electricity delivered by the Company at such location shall be furnished hereunder.

The actual delivery of service and the rendering of bills under this rate is contingent upon the installation of the necessary metering equipment by the Company; subject to both the availability of such meters from the Company's supplier and the conversion or installation procedures established by the Company.

All customers served on this rate must elect to take their total electric service under the metering installation as approved by the Company. If delivery is through more than one meter, except at the Company's option, the Monthly Charge for service through each meter shall be computed separately under this rate. If any electricity is delivered hereunder at a given location, then all electricity delivered by the Company at such location shall be furnished hereunder, except for service taken under rate E-10 or E-20.

MONTHLY CHARGE

The Monthly Charge will be the sum of the Customer Access Charge, the Distribution Expansion Charge and Energy Charges:

Customer Access Charge:	Set forth in the Service Agreement.
Distribution Expansion Charge:	$2.37 per kW times the Distribution Expansion Demand.

THE NARRAGANSETT ELECTRIC COMPANY
BUSINESS SERVICE - FLEXIBLE TIME-OF-USE PRICING (G-50)

Energy Charges: As shown on Attachment 1 of this rate.

The schedule of energy charges for a day will be posted to individual customer computer mail boxes and will be available to the Customer via a toll-free telephone number. The schedule will be posted by 3 p.m. of the prior week day, excluding holidays. Weekends and holidays will be priced under rate schedule 4 in each season. In the event that the Company is unable to transfer prices in the manner described above, the Company reserves the right to use an alternative communication method to transfer the schedule of energy charges to the customer such as via telephone or fax. In each season, except as provided above, price schedule 3 will be in effect if the Company fails to post the prices by 3 p.m. on the prior week day, excluding holidays.

Following the first twelve months of service under this rate, the Company shall compare the sum of the twelve monthly billings under this rate to the corresponding monthly billings under the G-30 rate and shall credit the customers with the amount the actual billings for the twelve month period exceed 110 percent of the billings that would have been made under the G-30 rate. No interest will be applied to this amount.

Definition of Holidays:

New Years' Day, Presidents' Day, Memorial Day, Independence Day, Columbus Day, Labor Day, Veterans' Day, Thanksgiving Day and Christmas Day. All holidays will be the nationally observed day.

Definition of Seasons:

Winter: The calendar months of January, February and December
Summer: The calendar months of June, July, August and September
Spring/Fall: The calendar months of March, April, May, October and November

Number of occurrences for each price schedule:

Season	Price Schedule	Number of Days
Winter	1	9
	2	18
	3	All other weekdays
	4	Weekends and Holidays
Summer	1	8
	2	8
	3	All other weekdays
	4	Weekends and Holidays
Spring/Fall	1	10
	2	20
	3	All other weekdays
	4	Weekends and Holidays

RESERVATION DEMAND

The Reservation Demand shall be set forth in the Service Agreement as the maximum billing demand of the customer within the base period. The provisions of the General Service Time-of-Use Rate G-30 shall define the billing demand.

DISTRIBUTION EXPANSION DEMAND

The Distribution Expansion Demand shall be the amount by which the customer's highest actual demands in any billing month exceeds its Reservation Demand during any month that service has been taken under this rate, provided however that the customer shall have the option to reset the Distribution Expansion Demand to current usage by agreeing to pay 120 percent of the Customer Access Charge and Distribution Expansion Charge for the three billing periods after this option is exercised. In addition, the Company reserves the right to adjust the Distribution Expansion Demand at the Customer's request to reflect the installation of verifiable Conservation and Load Management measures.

THE NARRAGANSETT ELECTRIC COMPANY

BUSINESS SERVICE - FLEXIBLE TIME-OF-USE PRICING (G-50)

PURCHASED POWER COST ADJUSTMENT

The prices under this rate as set forth under "Monthly Charge" may be adjusted from time to time in the manner provided in the Company's Purchased Power Cost Adjustment Provisions to reflect changes occurring after February 28, 1993 in the Primary Service for Resale Rate of the Company's supplier, New England Power Company.

ADJUSTMENT FOR COST OF FUEL

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Procedures for Fuel Review as from time to time effective in accordance with law.

CONSERVATION LOAD MANAGEMENT ADJUSTMENT

The amount determined under the preceding provisions shall be adjusted in accordance with the Company's Conservation and Load Management Adjustment Provision as from time to time effective in accordance with law.

CREDIT FOR HIGH VOLTAGE DELIVERY

If the Customer takes delivery at the Company's supply line voltage, not less than 2400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit of 39 cents per kilowatt of the Distribution Expansion Demand for such month shall be allowed against the amount determined under the preceding provisions.

An additional credit of $2.51 per kilowatt of the Distribution Expansion Demand for such month shall also be allowed if said customer accepts delivery at not less than 115,000 volts, and the Company is saved the cost of installing any transformer and associated equipment.

THE NARRAGANSETT ELECTRIC COMPANY

BUSINESS SERVICE - FLEXIBLE TIME-OF-USE PRICING (G-50)

SERVICE EXTENSION DISCOUNT

The Company will grant a five percent Service Extension Discount on the otherwise applicable base rate exclusive of the Customer Charge, the Purchased Power Cost Adjustment, the adjustment for phase-in of FAS 106, the Adjustment for Cost of Fuel, fuel expense collected in base rates, the Oil Conservation Adjustment, the Conservation and Load Management Adjustment, the Uniform Conservation Cost Adjustment, and any other adjustment mechanism approved or adopted by the Rhode Island Public Utilities Commission when the Customer (1) has an average annual demand of 200 kW or greater, (2) has signed a service agreement with the Company in which the Customer has agreed to provide the Company with five years prior written notice before purchasing, allowing to be purchased, or using electricity from a source other than the Company or installing or allowing to be installed a non-emergency generator for its use, and (3) has not provided written notice under the service agreement, provided, however, that no Service Extension Discount shall be applied when the Customer has an arrearage on its account at the time a bill is issued.

Any Customer giving notice under its service agreement shall have the option to shorten the notice provision to three years by repaying all Service Extension Discounts received from the Company over the prior two years with interest calculated at the rate approved by the Commission for crediting interest on customer deposits that is in effect at the time notice is given, and the Company shall credit such repayments to its Storm Contingency Fund. A Customer with generation at its location on June 12, 1994, shall be eligible for the Service Extension Discount if it has executed a service agreement under which it agrees not to increase the nameplate capacity of the generation at its location.

Any Customer who signs a service agreement by October 10, 1994 is eligible to receive a discount on their usage beginning May 15, 1994.

HIGH-VOLTAGE METERING ADJUSTMENT

The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1.0% will be allowed from the amount determined under the preceding provisions, excluding the Customer Access Charge.

GROSS EARNINGS TAX CREDIT FOR MANUFACTURERS

Consistent with the gross receipts tax exemption provided in Section 44-13-35 of Rhode Island General Laws, eligible manufacturing customers will receive credits according to the amounts shown in the schedule below (effective on the dates indicated):

Effective Date	Amount of Total Credit
July 1, 1994	1.031%
July 1, 1995	2.041%
July 1, 1996	3.030%
July 1, 1997	4.000%

Eligible manufacturing customers are those customers who have on file with the Company a valid certificate of exemption from the Rhode Island sales tax (under section 44-18-30(H) of Rhode Island General Laws) indicating the customer's status as a manufacturer. If the Division of Taxation (or other Rhode Island taxing authority with jurisdiction) disallows any part or all of the exemption as it applies to a customer, the customer will be required to reimburse the Company in the amount of the credits provided to such customer which were disallowed, including any interest required to be paid by the Company to such authority.

THE NARRAGANSETT ELECTRIC COMPANY

BUSINESS SERVICE - FLEXIBLE TIME-OF-USE PRICING (G-50)

TERMS AND CONDITIONS

The Company's Terms and Conditions in effect from time to time, where not inconsistent with any specific provisions hereof, are a part of this rate.

Effective May 1, 1995

FILE: RTPSCH9R
RANGE: SPR1
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SPRING/FALL MONTHS
CUSTOMERS SERVED AT PRIMARY DISTRIBUTION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02222	$0.02222	$0.02222	$0.02222
2	$0.02222	$0.02222	$0.02222	$0.02222
3	$0.02222	$0.02222	$0.02222	$0.02222
4	$0.02222	$0.02222	$0.02222	$0.02222
5	$0.02222	$0.02222	$0.02222	$0.02222
6	$0.02223	$0.02222	$0.02222	$0.02222
7	$0.02285	$0.02223	$0.02222	$0.02222
8	$0.03929	$0.02562	$0.02248	$0.02222
9	$0.06584	$0.04673	$0.03478	$0.02222
10	$0.07139	$0.04873	$0.03473	$0.02222
11	$0.07399	$0.05004	$0.03479	$0.02222
12	$0.06887	$0.04655	$0.03449	$0.02222
13	$0.05806	$0.04066	$0.03418	$0.02222
14	$0.05222	$0.03864	$0.03419	$0.02222
15	$0.04449	$0.03674	$0.03412	$0.02222
16	$0.04175	$0.03600	$0.03408	$0.02222
17	$0.06627	$0.04082	$0.03419	$0.02222
18	$0.08916	$0.06418	$0.03500	$0.02222
19	$0.09361	$0.07296	$0.03713	$0.02222
20	$0.08515	$0.05505	$0.03614	$0.02222
21	$0.06251	$0.03832	$0.03422	$0.02222
22	$0.02551	$0.02224	$0.02222	$0.02222
23	$0.02224	$0.02222	$0.02222	$0.02222
24	$0.02222	$0.02222	$0.02222	$0.02222

*Includes fuel in base of $0.01500

The price called for_____________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: SPR2
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SPRING/FALL MONTHS
CUSTOMERS SERVED AT SECONDARY VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02227	$0.02227	$0.02227	$0.02227
2	$0.02227	$0.02227	$0.02227	$0.02227
3	$0.02227	$0.02227	$0.02227	$0.02227
4	$0.02227	$0.02227	$0.02227	$0.02227
5	$0.02227	$0.02227	$0.02227	$0.02227
6	$0.02228	$0.02227	$0.02227	$0.02227
7	$0.02292	$0.02228	$0.02227	$0.02227
8	$0.03991	$0.02578	$0.02254	$0.02227
9	$0.06725	$0.04752	$0.03519	$0.02227
10	$0.07298	$0.04958	$0.03512	$0.02227
11	$0.07567	$0.05093	$0.03519	$0.02227
12	$0.07039	$0.04733	$0.03487	$0.02227
13	$0.05921	$0.04125	$0.03455	$0.02227
14	$0.05319	$0.03916	$0.03456	$0.02227
15	$0.04520	$0.03719	$0.03449	$0.02227
16	$0.04237	$0.03643	$0.03447	$0.02227
17	$0.06770	$0.04142	$0.03457	$0.02227
18	$0.09134	$0.06554	$0.03540	$0.02227
19	$0.09593	$0.07460	$0.03761	$0.02227
20	$0.08719	$0.05611	$0.03658	$0.02227
21	$0.06382	$0.03883	$0.03460	$0.02227
22	$0.02568	$0.02229	$0.02227	$0.02227
23	$0.02229	$0.02227	$0.02227	$0.02227
24	$0.02227	$0.02227	$0.02227	$0.02227

*Includes fuel in base of $0.01500

The price called for_________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: SPR3
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SPRING/FALL MONTHS
CUSTOMERS SERVED AT TRANSMISSION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02193	$0.02193	$0.02193	$0.02193
2	$0.02193	$0.02193	$0.02193	$0.02193
3	$0.02193	$0.02193	$0.02193	$0.02193
4	$0.02193	$0.02193	$0.02193	$0.02193
5	$0.02193	$0.02193	$0.02193	$0.02193
6	$0.02193	$0.02193	$0.02193	$0.02193
7	$0.02248	$0.02193	$0.02193	$0.02193
8	$0.03700	$0.02492	$0.02214	$0.02193
9	$0.06054	$0.04368	$0.03313	$0.02193
10	$0.06544	$0.04544	$0.03308	$0.02193
11	$0.06774	$0.04660	$0.03314	$0.02193
12	$0.06322	$0.04352	$0.03288	$0.02193
13	$0.05367	$0.03832	$0.03260	$0.02193
14	$0.04853	$0.03654	$0.03261	$0.02193
15	$0.04170	$0.03485	$0.03254	$0.02193
16	$0.03927	$0.03421	$0.03251	$0.02193
17	$0.06092	$0.03846	$0.03261	$0.02193
18	$0.08112	$0.05909	$0.03332	$0.02193
19	$0.08505	$0.06682	$0.03521	$0.02193
20	$0.07758	$0.05103	$0.03433	$0.02193
21	$0.05760	$0.03625	$0.03264	$0.02193
22	$0.02483	$0.02194	$0.02193	$0.02193
23	$0.02194	$0.02193	$0.02193	$0.02193
24	$0.02193	$0.02193	$0.02193	$0.02193

*Includes fuel in base of $0.01500

The price called for____________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: SUM1
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SUMMER MONTHS
CUSTOMERS SERVED AT PRIMARY DISTRIBUTION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02225	$0.02225	$0.02225	$0.02224
2	$0.02225	$0.02225	$0.02225	$0.02224
3	$0.02225	$0.02225	$0.02225	$0.02224
4	$0.02225	$0.02225	$0.02225	$0.02224
5	$0.02225	$0.02225	$0.02225	$0.02224
6	$0.02225	$0.02225	$0.02225	$0.02224
7	$0.02225	$0.02225	$0.02225	$0.02224
8	$0.02225	$0.02225	$0.02225	$0.02224
9	$0.03587	$0.03431	$0.03423	$0.02224
10	$0.16540	$0.04029	$0.03431	$0.02224
11	$0.48422	$0.09298	$0.03530	$0.02224
12	$0.66341	$0.19305	$0.03728	$0.02224
13	$0.69705	$0.23721	$0.03803	$0.02224
14	$0.73730	$0.33658	$0.04196	$0.02224
15	$0.73014	$0.29563	$0.04256	$0.02224
16	$0.69138	$0.21431	$0.04062	$0.02224
17	$0.64742	$0.18160	$0.03922	$0.02224
18	$0.47096	$0.09269	$0.03538	$0.02224
19	$0.24000	$0.05781	$0.03434	$0.02224
20	$0.13164	$0.05657	$0.03428	$0.02224
21	$0.16850	$0.05953	$0.03427	$0.02224
22	$0.05744	$0.03468	$0.02225	$0.02224
23	$0.02233	$0.02269	$0.02225	$0.02224
24	$0.02225	$0.02225	$0.02225	$0.02224

*Includes fuel in base of $0.01500

The price called for________________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: SUM2
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SUMMER MONTHS
CUSTOMERS SERVED AT SECONDARY VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02230	$0.02230	$0.02230	$0.02230
2	$0.02230	$0.02230	$0.02230	$0.02230
3	$0.02230	$0.02230	$0.02230	$0.02230
4	$0.02230	$0.02230	$0.02230	$0.02230
5	$0.02230	$0.02230	$0.02230	$0.02230
6	$0.02230	$0.02230	$0.02230	$0.02230
7	$0.02230	$0.02230	$0.02230	$0.02230
8	$0.02230	$0.02230	$0.02230	$0.02230
9	$0.03639	$0.03476	$0.03468	$0.02230
10	$0.17110	$0.04098	$0.03477	$0.02230
11	$0.50267	$0.09578	$0.03579	$0.02230
12	$0.68902	$0.19985	$0.03785	$0.02230
13	$0.72401	$0.24577	$0.03863	$0.02230
14	$0.76587	$0.34912	$0.04272	$0.02230
15	$0.75841	$0.30653	$0.04334	$0.02230
16	$0.71811	$0.22196	$0.04131	$0.02230
17	$0.67240	$0.18793	$0.03987	$0.02230
18	$0.48887	$0.09548	$0.03588	$0.02230
19	$0.24868	$0.05920	$0.03480	$0.02230
20	$0.13597	$0.05791	$0.03473	$0.02230
21	$0.17433	$0.06099	$0.03472	$0.02230
22	$0.05891	$0.03524	$0.02231	$0.02230
23	$0.02239	$0.02276	$0.02230	$0.02230
24	$0.02230	$0.02230	$0.02230	$0.02230

*Includes fuel in base of $0.01500

The price called for______________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: SUM3
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE SUMMER MONTHS
CUSTOMERS SERVED AT TRANSMISSION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02193	$0.02193	$0.02193	$0.02193
2	$0.02193	$0.02193	$0.02193	$0.02193
3	$0.02193	$0.02193	$0.02193	$0.02193
4	$0.02193	$0.02193	$0.02193	$0.02193
5	$0.02193	$0.02193	$0.02193	$0.02193
6	$0.02193	$0.02193	$0.02193	$0.02193
7	$0.02193	$0.02193	$0.02193	$0.02193
8	$0.02193	$0.02193	$0.02193	$0.02193
9	$0.03392	$0.03257	$0.03249	$0.02193
10	$0.14656	$0.03777	$0.03257	$0.02193
11	$0.42378	$0.08358	$0.03343	$0.02193
12	$0.57961	$0.17059	$0.03514	$0.02193
13	$0.60886	$0.20899	$0.03579	$0.02193
14	$0.64386	$0.29540	$0.03921	$0.02193
15	$0.63763	$0.25980	$0.03973	$0.02193
16	$0.60392	$0.18909	$0.03804	$0.02193
17	$0.56570	$0.16063	$0.03683	$0.02193
18	$0.41225	$0.08333	$0.03350	$0.02193
19	$0.21142	$0.05299	$0.03260	$0.02193
20	$0.11719	$0.05192	$0.03253	$0.02193
21	$0.14925	$0.05449	$0.03252	$0.02193
22	$0.05253	$0.03274	$0.02193	$0.02193
23	$0.02200	$0.02231	$0.02193	$0.02193
24	$0.02193	$0.02193	$0.02193	$0.02193

*Includes fuel in base of $0.01500

The price called for______________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: WIN1
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE WINTER MONTHS
CUSTOMERS SERVED AT PRIMARY DISTRIBUTION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02225	$0.02224	$0.02224	$0.02224
2	$0.02225	$0.02224	$0.02224	$0.02224
3	$0.02225	$0.02224	$0.02224	$0.02224
4	$0.02225	$0.02224	$0.02224	$0.02224
5	$0.02225	$0.02224	$0.02224	$0.02224
6	$0.02225	$0.02225	$0.02224	$0.02224
7	$0.02436	$0.02271	$0.02228	$0.02224
8	$0.12179	$0.04600	$0.02829	$0.02224
9	$0.22518	$0.07996	$0.04397	$0.02224
10	$0.26136	$0.07841	$0.04207	$0.02224
11	$0.27316	$0.07401	$0.04000	$0.02224
12	$0.22995	$0.05822	$0.03740	$0.02224
13	$0.13327	$0.04244	$0.03544	$0.02224
14	$0.10194	$0.03720	$0.03500	$0.02224
15	$0.07088	$0.03485	$0.03441	$0.02224
16	$0.06039	$0.03451	$0.03428	$0.02224
17	$0.24763	$0.05143	$0.03553	$0.02224
18	$0.43735	$0.31792	$0.06672	$0.02224
19	$0.43615	$0.28141	$0.06148	$0.02224
20	$0.38135	$0.10649	$0.04182	$0.02224
21	$0.21524	$0.04502	$0.03558	$0.02224
22	$0.03958	$0.02231	$0.02225	$0.02224
23	$0.02242	$0.02224	$0.02224	$0.02224
24	$0.02225	$0.02224	$0.02224	$0.02224

*Includes fuel in base of $0.01500

The price called for____________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: WIN2
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE WINTER MONTHS
CUSTOMERS SERVED AT SECONDARY VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02230	$0.02230	$0.02230	$0.02230
2	$0.02230	$0.02230	$0.02230	$0.02230
3	$0.02230	$0.02230	$0.02230	$0.02230
4	$0.02230	$0.02230	$0.02230	$0.02230
5	$0.02230	$0.02230	$0.02230	$0.02230
6	$0.02231	$0.02230	$0.02230	$0.02230
7	$0.02450	$0.02278	$0.02234	$0.02230
8	$0.12558	$0.04695	$0.02857	$0.02230
9	$0.23276	$0.08209	$0.04476	$0.02230
10	$0.27030	$0.08049	$0.04278	$0.02230
11	$0.28253	$0.07592	$0.04065	$0.02230
12	$0.23770	$0.05954	$0.03793	$0.02230
13	$0.13740	$0.04316	$0.03589	$0.02230
14	$0.10491	$0.03773	$0.03545	$0.02230
15	$0.07267	$0.03530	$0.03482	$0.02230
16	$0.06179	$0.03494	$0.03470	$0.02230
17	$0.25605	$0.05249	$0.03600	$0.02230
18	$0.45288	$0.32898	$0.06836	$0.02230
19	$0.45163	$0.29110	$0.06292	$0.02230
20	$0.39478	$0.10962	$0.04253	$0.02230
21	$0.22245	$0.04585	$0.03605	$0.02230
22	$0.04028	$0.02237	$0.02231	$0.02230
23	$0.02248	$0.02230	$0.02230	$0.02230
24	$0.02230	$0.02230	$0.02230	$0.02230

*Includes fuel in base of $0.01500

The price called for______________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

FILE: RTPSCH9R
RANGE: WIN3
05-Apr-95

THE NARRAGANSETT ELECTRIC COMPANY
FLEX BASE RATE PRICE SCHEDULES
(EXCL. PPCA, CC FACTORS & FUEL)
FOR THE WINTER MONTHS
CUSTOMERS SERVED AT TRANSMISSION VOLTAGE

HOUR ENDING	PRICE SCHEDULE 1	PRICE SCHEDULE 2	PRICE SCHEDULE 3	PRICE SCHEDULE 4
1	$0.02193	$0.02193	$0.02193	$0.02193
2	$0.02193	$0.02193	$0.02193	$0.02193
3	$0.02193	$0.02193	$0.02193	$0.02193
4	$0.02193	$0.02193	$0.02193	$0.02193
5	$0.02193	$0.02193	$0.02193	$0.02193
6	$0.02193	$0.02193	$0.02193	$0.02193
7	$0.02377	$0.02232	$0.02196	$0.02193
8	$0.10871	$0.04263	$0.02720	$0.02193
9	$0.19902	$0.07241	$0.04104	$0.02193
10	$0.23056	$0.07106	$0.03938	$0.02193
11	$0.24085	$0.06722	$0.03758	$0.02193
12	$0.20317	$0.05346	$0.03530	$0.02193
13	$0.11889	$0.03969	$0.03360	$0.02193
14	$0.09158	$0.03513	$0.03321	$0.02193
15	$0.06449	$0.03309	$0.03269	$0.02193
16	$0.05535	$0.03278	$0.03259	$0.02193
17	$0.21859	$0.04754	$0.03367	$0.02193
18	$0.38400	$0.27988	$0.06086	$0.02193
19	$0.38294	$0.24804	$0.05630	$0.02193
20	$0.33517	$0.09554	$0.03916	$0.02193
21	$0.19035	$0.04195	$0.03372	$0.02193
22	$0.03704	$0.02198	$0.02193	$0.02193
23	$0.02207	$0.02193	$0.02193	$0.02193
24	$0.02193	$0.02193	$0.02193	$0.02193

*Includes fuel in base of $0.01500

The price called for______________________________is indicated by the checked box below

Price Schedule 1 ☐
Price Schedule 2 ☐
Price Schedule 3 ☐
Price Schedule 4 ☐

(rsp\puc.dec)

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

IN RE: TARIFF FILING MADE BY :
THE NARRAGANSETT ELECTRIC :
COMPANY ON JULY 2, 1990 : DOCKET NO. 1976

REPORT AND ORDER

On July 2, 1990, the Narragansett Electric Company (the "Company") filed an application with the Rhode Island Public Utilities Commission (the "Commission") seeking authorization for a general rate increase in the amount of $18,680,000, or approximately 4.9%. On July 19, 1990, pursuant to R.I.G.L. §39-3-11, the Commission suspended the filing for a period of five months beyond the proposed effective date of August 1, 1990 (Order No. 13352).

The following table summarizes the recent rate filings of the Company:

Year Filed	Docket Number	Amount Requested	Amount Granted
1981	1591	$ 15,396,000	$ 9,386,000
1982	1659	$ 15,365,000	$ 6,245,000
1984	1719	$ 13,474,000	$ [1,484,000]*
1989	1938	$ 15,471,000	$ 5,760,000

*Revenues were reduced by this amount.

On September 7, 1990, the Commission entered an Order allowing the Energy Council for Rhode Island ("TEC-RI") to intervene in this matter (Order No. 13394).

The Commission conducted two public hearing to solicit public response to the Company's request for a rate increase. The first public hearing occurred on September 25, 1990 at the North Kingstown High School Auditorium, North Kingstown, Rhode Island. The second public hearing occurred on October 15, 1990 at the State House, Providence, Rhode Island.

Formal hearings on the Company's application commenced on October 9, 1990 and continued through October 15, 1990 with witnesses for the Company subject to cross-examination conducted by the Division of Public Utilities and Carriers ("Division"), TEC-RI, and the Commission.

The following appearances were entered at the October 9, 1990 hearing:

FOR THE COMPANY	Ronald Gerwatowski, Esq. Thomas Robinson, Esq.
FOR THE DIVISION AND DEPARTMENT OF ATTORNEY GENERAL	Brenda K. Gaynor Special Assistant Attorney General Sheldon Whitehouse, Esq. Assistant Attorney General
FOR THE ENERGY COUNCIL OF RHODE ISLAND	Andrew J. Newman, Esq.
FOR THE COMMISSION	Robert S. Parker, Esq.

Included among the Company's requests for relief in this Docket was the establishment of a Revenue Tracking Mechanism ("RTM") through which the Company would systematically adjust revenues for fluctuations in short term sales. On October 15, 1990 the Commission rendered a bench decision denying without prejudice the Company's request for an RTM in this docket.

Prior to the scheduled cross-examination of the Division's witnesses, the parties filed a stipulation (the "Stipulation") fully resolving all matters pending in this case. Joint Ex. "A" (Copy attached).

The Commission's duty upon the receipt of a settlement is "to evaluate the proposal in all its aspects to determine whether or not it is just, reasonable and fair to both the rate payers and the Company." Re: Newport Electric Corporation, Docket No. 1872 (1987), p. 3. Ultimately, the Commission must decide whether the settlement agreement is "in the public interest." Re: New England Telephone and Telegraph Company, Docket No. 1780 (1985), p. 16.

The Commission conducted a hearing on December 17, 1990 to evaluate the fairness of the proposed settlement. The Company produced two witnesses from the New England Power Service Company to respond to questioning by the Commission: Terry L. Schwennesen, Senior Rate Analyst and Robert H. McLaren, Director of Corporate Finance. Testifying on behalf of the Division were David J. Effron, Utility Consultant with Berkshire Consulting Services, and Stephen Scialabba, Chief Accountant for the Division.

On December 20, 1990, an open meeting was held by the Commission. After due consideration of the record and the Stipulation, the Commission unanimously voted to approve the Stipulation with the following comments.

1. Rate Increase of $13,000,000 (3.2%)

The Company originally sought a rate increase of $18,680,000 which, following regular suspensions, would become effective on April 1, 1991. See Exhibit 3(a), p. 1. The Division originally posited that the Company's revenue deficiency is approximately $10,528,000. Div. Ex. 24A; Div. Ex. 24 at p. 4.

The Stipulation provides for a rate increase of $13,000,000. We note that this figure was not the result of the parties' simply accepting a middle ground between the figures provided by the Division and the Company. The settlement figure was reached only following the Company's submission of additional documentation to the Division substantiating more fully its need for additional revenues. David J. Effron, a consultant specializing in utility regulation, testified on behalf of the Division that submission by the Company of supplemental data in such areas as additions to plant in service substantiated the Company's need for additional revenue in an amount greater than the $10,528,000 increase previously recommended by the Division. (12/29/90 Tr. p. 27-28).

Mr. Scialabba testified as to the "fair and reasonable" nature of the Stipulation. (12/29/90 Tr., p. 14). Mr. Effron concurred that the Stipulation is in the best interest of the rate payer. (12/29/90 Tr., p. 31). The Commission agrees that the increase of $13,000,000 as set forth in the Stipulation is appropriate and meets the burden of being just, reasonable and fair to both the consumer and the Company.

2. Rates of Return

The Company and the Division have agreed that effective April 1, 1991, the monthly earnings reports filed with the Commission will adopt a rate of return on equity of 12.75% and the Company's actual permanent capital structure will be used to calculate an overall rate of return. (Stip. at p. 3; 12/17/89 Tr., p. 16).

3. Allowance for Funds Used During Construction ("AFUDC")

We accept the agreed rate of return on common equity of 12.15%, effective April 1, 1991, for purposes of calculating the AFUDC rate.

4. Percentage of Income Payment Plan

While the Commission recognizes that the terms of the expansion of the Percent of Income Payment Plan (PIPP) Program will be specifically addressed in Docket No. 1725, we approve and support the Company's continued cooperation with various state governmental agencies in the implementation, administration and expansion of the PIPP Program.

5. Cost Allocation and Rate Design

As set forth in the Stipulation, the Company, Division and TEC-RI agree that the methodology and results of the Company's cost of service study are reasonable. The Commission agrees and approves the cost allocation and rate design as set forth in the Stipulation as reasonable and in the public interest.

6. Streetlighting

In Docket No. 1938, the Commission approved a 5-year phased increase in S-6 and S-7 streetlighting rates. The parties have agreed that these rate increases as set forth in Docket No. 1938 are unaffected by the Stipulation in this docket. We approve the application of all additional revenues realized through these streetlighting increases to Conservation and Loan Management activities or to otherwise benefit the Company's customers.

ORDER

Accordingly, it is hereby

(13595) ORDERED:

1. That the tariff filed by the Narragansett Electric Company on July 2, 1990 which was designed to produce additional annual revenues in the amount of $18,680,000 is hereby denied and dismissed;

2. That the Narragansett Electric Company is hereby instructed to file with the Public Utilities Commission new rates and charges designed to recover additional annual revenues in the amount of $13,000,000;

3. That the approved increase shall be applied as set forth in Joint Ex. "A";

4. That the new rates shall take effect for electrical consumption on and after April 1, 1991;

5. That the Narragansett Electric Company shall comply with all other instructions contained in this Report and Order.

DATED AND EFFECTIVE AT PROVIDENCE, RHODE ISLAND, ON THE 2ND DAY OF APRIL, 1991 PURSUANT TO A DECEMBER 20, 1990 OPEN MEETING DECISION. WRITTEN ORDER ISSUED THIS 2ND DAY OF APRIL, 1991.

PUBLIC UTILITIES COMMISSION

James Malachowski, Chairman

*

Frank L. Nunes, Commissioner

Lila M. Sapinsley, Commissioner

*Commissioner Nunes concurs but he was unavailable for signature.

EXHIBIT A

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

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PUBLIC UTILITIES COMMISSION

RE: THE NARRAGANSETT ELECTRIC COMPANY -- INVESTIGATION BY THE COMMISSION AS TO THE PROPRIETY OF PROPOSED TARIFF CHANGES	Docket No. 1976

STIPULATION OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS, THE ENERGY COUNCIL OF RHODE ISLAND, AND THE NARRAGANSETT ELECTRIC COMPANY

Now come The Division of Public Utilities and Carriers (the Division), The Energy Council of Rhode Island (TEC-RI), and The Narragansett Electric Company (the Company) and state as follows:

WHEREAS the Company, on July 2, 1990, filed with the Commission a request to increase its rates by $18,680,000, or 4.9%;

WHEREAS the Division has retained a team of experts and conducted a thorough and complete investigation of the Company's proposal;

WHEREAS the Division, pursuant to its investigation, has recommended that the Company's request to increase rates be reduced to $10,528,000;

WHEREAS the Company, TEC-RI, and the Division have engaged in settlement discussions with respect to the Company's revenue requirements for the rate year, April 1, 1991 through March 31, 1992, and with respect to issues of cost allocation and rate design;

AND WHEREAS the parties hereto have reached a comprehensive agreement fully resolving all matters pending in this case;

NOW, THEREFORE, the Division, TEC-RI, and the Company agree and stipulate as follows:

RATE INCREASE

1. The Company's rates shall be revised to increase annual revenues by $13,000,000, or about 3.2%, designed on kilowatthour sales of 4,490 gigawatthours and using an overall rate of return of 10.62% (including a 12.75% return on equity).
2. The rate increase shall take effect for usage on and after April 1, 1991.
3. The Company shall file, no later than December 7, 1990, revised rate schedules to implement the revenue increase specified above.
4. The revenue increase provided for above does not reflect the recovery of any costs associated with the Company's currently approved or proposed conservation and load management programs. All issues relating to the recovery by the Company of costs associated with conservation and load management, including without limitation, recovery of maximizing or efficiency

incentives, shall be addressed separately in Docket 1939.

5. The revenue increase specified above will provide just and reasonable rates.

MONTHLY EARNINGS REPORTS

6. For purposes of the monthly earnings reports filed with the Commission, commencing with the report for April 1, 1991, the Company's allowed return on equity shall be specified as 12.75% and the Company's actual permanent capital structure will be used to calculate the overall return.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

7. For purposes of calculating an allowance for funds used during construction, the Company will use a rate of return on common equity of 12.25%, effective April 1, 1991.

PERCENTAGE OF INCOME PAYMENT PLAN

8. The Company agrees to continue its cooperation with the Governor's Office of Housing, Energy, and Intergovernmental Relations, and other interested agencies and organizations, in connection with the implementation and administration of the Percentage of Income Payment Plan (PIPP) program currently available to households eligible for assistance under the federal Low Income Home Energy Assistance Program.

Further, subject to the Commission's approval in Docket 1725, the Company agrees to support and cooperate in the expansion of the PIPP program beyond Providence and other areas currently served by the program to the remainder of its service territory.

COST ALLOCATION AND RATE DESIGN

9. The techniques used in, and results of, the Company's fully allocated cost of service study are reasonable.

10. The annual revenue increase specified in this stipulation shall be allocated to the Company's various rate classes as shown in column 6 on Attachment A to this stipulation.

11. Customers taking service under the Company's Supplemental Security Income Assistance Rate (A-65) shall not have their rate increased by the annual revenue increase specified in this stipulation.

12. The other miscellaneous rate design changes prepared by the Company shall be approved as filed. These changes include: increasing the transformer ownership credit to 39¢ per kW; specified modifications to the list of available streetlight fixtures; a revision to the Company's streetlighting discontinuance policy; and revising the maximum control period under the Company's A-11 and A-15 controlled water heater rates.

STREETLIGHTING

13. The parties acknowledge that the five-year phased increases to the S-6 and S-7 streetlighting rates which was agreed to in the stipulation in Docket 1938 shall continue, as agreed to and approved in that docket. In addition, such streetlighting increases continue to be subject to the condition that any additional revenues realized by the Company pursuant to such increases shall be used to fund Conservation and Load Management activities or otherwise applied to or for the benefit of the Company's customers.

TERMS AND CONDITIONS

14. The proposed deletion of paragraph 27 of the Company's terms and conditions for service, relating to the designation of holidays, shall be approved.

MISCELLANEOUS PROVISIONS

15. Other than as expressly stated herein, the making of this stipulation establishes no principles and shall not be deemed to foreclose any party from making any contention in any future proceeding or investigation.

16. The acceptance of this stipulation by the Division shall not in any respect commit the Division to taking any particular position on the proposed transfer of property by the Company to its affiliate, New England Power Company, in connection with the Company's

Manchester Street Repowering Project. All issues relating to such project and transfer shall be addressed separately from this docket 1976.

17. Other than as expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any subsequent rate proceeding.

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

19. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

Respectfully Submitted,

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS
By its Attorney,

Brenda K. Gaynor
Special Assistant Attorney General
72 Pine Street
Providence, Rhode Island 02903

THE ENERGY COUNCIL OF RHODE ISLAND
By its Attorney,

Andrew J. Newman

Andrew J. Newman
Rubin and Rudman
50 Rowes Wharf
Boston, MA 02110

RHODE ISLAND CONSUMERS' COUNCIL
By

Title:
365 Broadway
Providence, Rhode Island 02909

THE NARRAGANSETT ELECTRIC COMPANY
By its Attorney,

Ronald T. Gerwatowski
280 Melrose Street
Providence, Rhode Island 02907

Date: December 7, 1990

Respectfully Submitted,

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS
By its Attorney,

Brenda K. Gaynor
Special Assistant Attorney General
72 Pine Street
Providence, Rhode Island 02903

THE ENERGY COUNCIL OF RHODE ISLAND
By its Attorney,

Andrew J. Newman
Rubin and Rudman
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Boston, MA 02110

RHODE ISLAND CONSUMERS' COUNCIL
By Hugo L. Ricci Jr.

Legal Counsel
Title
365 Broadway
Providence, Rhode Island 02909

THE NARRAGANSETT ELECTRIC COMPANY
By its Attorney,

Ronald T. Gerwatowski
280 Melrose Street
Providence, Rhode Island 02907

Date: December 7, 1990

.ME:SETOFER3
.. .JENAME REVREQ3

THE NARRAGANSETT ELECTRIC COMPANY
R.I.P.U.C # 1976
ATTACHMENT A

ALLOCATION OF REVENUE INCREASE AMONG RATE CLASSES

RATE	PRESENT REVENUE CALCULATED @ W-12(a)(HQ) (1)	SETTLEMENT REVENUE INCREASE CALCULATED @ FULLY ALLOCATED COST (2)	PERCENT INCREASE (DECREASE) (3)	SETTLEMENT CALCULATED @ FULLY ALLOCATED COST W/ SUBSIDY TO RATES V & STLTG (4)	PERCENT INCREASE (DECREASE) (5)	SETTLEMENT REVENUE PROPOSAL CALCULATED @ W-12(a)(HQ) (6)	PERCENT INCREASE (DECREASE) (7)
A-10	$131,537,674	$5,388,052	4.10%	$6,138,650	4.67%	$5,801,707	4.41%
A-11	$36,987,419	$1,783,145	4.82%	$1,992,203	5.39%	$1,898,357	5.13%
A-15	$136,474	$6,662	4.88%	$7,444	5.45%	$7,093	5.20%
A-65	$566,304	$22,665	4.00%	$25,810	4.56%	$0	0.00%
C-02	$33,457,205	($1,553)	-0.00%	$182,352	0.55%	$99,797	0.30%
G-00	$80,661,793	$2,730,926	3.39%	$3,180,261	3.94%	$2,978,555	3.69%
G-30	$98,019,185	$1,687,330	1.72%	$2,211,150	2.26%	$1,976,007	2.02%
H-30	$11,947,981	($1,034,205)	-8.66%	($978,550)	-8.19%	$0	0.00%
T	$2,269,234	$137,143	6.04%	$150,018	6.61%	$144,238	6.36%
V	$1,118,302	$281,840	25.20%	$86,157	7.70%	$86,157	7.70%
STLTG	$6,166,008	$1,997,995	32.40%	$3,907	0.06%	$3,907	0.06%
E-01	$119,029	N/A	N/A	$599	0.50%	$4,182	3.51%
TOTAL	$402,986,608	$13,000,000	3.23%	$13,000,000	3.23%	$13,000,000	3.23%

FOOTNOTES:

COLUMN 1: PRESENT REVENUES @ SETTLEMENT FORECAST 4490 GWH. STREETLIGHTING REVENUES ALREADY INCLUDE INCREASES OF APPROXIMATELY 9% ON BOTH JANUARY 1, 1991 AND JANUARY 1, 1992.

COLUMN 2: SETTLEMENT INCREASE AT FULLY ALLOCATED REVENUE REQUIREMENT.

COLUMN 3: COLUMN 2 / COLUMN 1

COLUMN 4: SAME AS COLUMN 2 EXCEPT 1)RATE V IS SET AT ONE THIRD OF THE WAY TO FULLY ALLOCATED COST, AND 2)STREETLIGHTING IS SET AT LEVELS APPROVED IN DOCKET 1938. TRAFFIC LIGHTING RATE R IS SET AT TOTAL COMPANY INCREASE.

COLUMN 5: COLUMN 4 / COLUMN 1

COLUMN 6: SAME AS COLUMN 4 EXCEPT RATES A-65 AND H-30 ARE HELD AT 0 INCREASE AND DECREASE, RESPECTIVELY. RATE E-01 SET AT TOTAL COMPANY INCREASE.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:
NEWPORT ELECTRIC CORPORATION
CORPORATION APPLICATION TO
CHANGE RATE SCHEDULES

Docket No. 2036

Dated September 28, 1992

REPORT AND ORDER

Table of Contents

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:
NEWPORT ELECTRIC CORPORATION
COMPANY APPLICATION TO
CHANGE RATE SCHEDULES

Docket No. 2036

Dated September 28, 1992

REPORT AND ORDER

Introduction

On December 27, 1991, Newport Electric Corporation (hereafter the "Company" or "Newport") filed two Applications for Rate Relief with accompanying rate schedules with this Commission. The first, Phase I, was a request to increase its revenues by $6,093,664, an increase of approximately 10.98%, to become effective January 27, 1992.

The second request, Phase II, was for an additional $1,249,867, an increase of 2.0%, would become effective on January 1, 1993. The Phase II request pertains only to the impact of the Financial Accounting Standards Board Statement 106 ("FASB 106"), which this Commission has now under consideration in a generic docket, Docket 2045, and therefore will not address in this Report and Order. Docket No. 2045, initiated on April 7, 1992, addresses the need to fund the provision of post-retirement benefits other than pensions for all utilities subject to FASB 106 and under the jurisdiction of this Commission.

The Rhode Island Public Utilities Commission (hereafter the "Commission"), pursuant to Section 39-3-11 of the General Laws, suspended the effective date until June 26, 1992, (Order No. 13841) five months beyond the effective date of January 27, 1992. The effective date was again suspended on June 16, 1992, Order No. 13943, for three months to September 26, 1992, with a Report to issue on the next business day, September 28, 1992.

On February 3, 1992, The Energy Council of Rhode Island (hereafter called "TEC-RI") filed a motion to intervene and as the motion was timely, reasonable and without objection the Commission granted said request on March 13, 1992 (Order No. 13874).

On January 30, 1992, The United States Department of the Navy (hereafter called "NAVY") filed a motion to intervene and as the motion was timely, reasonable and without objection the Commission granted said request on March 13, 1992 (Order No. 13874).

On February 27, 1992, The Rhode Island Department of Economic Development (hereafter called "DED") filed a motion to intervene and as the motion was timely, reasonable and without objection the Commission granted said request on March, 13, 1992 (Order No. 13847).

The Company's recent rate history and filings are as follows:

Docket	Increase Sought	Increase Approved	Effective Date
1435	$ 453,000	$0	6/12/80
1510	$2,112,000	$1,080,000	2/04/81
1599	$1,512,000	$ 999,000	10/01/81
1801	$2,208,000	$1,384,000	9/05/85
1872	$1,753,000	$ 633,000	9/07/87

The following appearances were entered in this proceeding:

FOR THE COMPANY:	David A. Fazzone, Esq. of McDermott, Will & Emery
FOR THE DIVISION OF PUBLIC UTILITIES AND CARRIERS AND THE DEPARTMENT OF THE ATTORNEY GENERAL:	Julio C. Mazzoli, Esq. Special Assistant Attorney General
FOR TEC-RI THE ENERGY COUNCIL OF RHODE ISLAND:	Paul R. Ivaska, Esq.
FOR THE DEPARTMENT OF THE NAVY:	Audrey Van Dyke, Esq. Naval Facilities Engineering Command
FOR THE DEPARTMENT OF ECONOMIC DEVELOPMENT:	Daniel J. Schatz, Esq. of Flanders & Medeiros Inc.
FOR THE COMMISSION:	Joseph B. McDonough, Esq.

Description of the Company

Newport Electric Corporation is a wholly owned subsidiary of Eastern Utilities Associates (hereafter called"EUA"). The Company is one of approximately nine EUA affiliated companies, the others being: Montaup Electric Company, Eastern Edison Company, EUA Service Company, EUA Cogenex Corporation, EUA Ocean State Corporation, EUA Power Corporation, EUA Energy Investment Corporation, and Blackstone Valley Electric Company. The Company serves approximately 31,000 customers, 27,000 are residential customers. It's largest customer is the United States Department of the Navy, which takes approximately 20% of Newport's load. It provides service to Aquidneck, Canonicut, and Prudence Island which includes the city of Newport, and the towns of Middletown, Portsmouth, and Jamestown. The service area covers fifty-five square miles all of which is in the jurisdiction of this Commission. The Company generates it's own power, obtains power from a jointly owned facility, and purchases electricity, directly or indirectly, from supply contracts with other New England utilities including Ocean State Power I and II.

Travel of the Case

On April 13, 1992 the Commission held a hearing upon the motion of TEC-RI, an intervener, for the purpose of compelling a response by Newport to certain data requests made by TEC-RI.

The Company prefiled testimony from twelve witnesses starting with then Company President, Mr. Robert G. Powderly, who gave general background on acquisition/merger and stability of the Company and specific information on customer relations, and public affairs programs, and data pertaining to charitable contributions.

Mr. Clifford Herbert gave written testimony as to the financial condition and capital structure of Newport. Mr. Zvi Benderly, a consultant, prefiled testimony recommending a rate of return on common equity. Mr. Larry Settle presented testimony on Cost of Service and the lead/lag Study. Mr. Carl Zoubra prefiled testimony on the capital budget and construction projects. Dr. Alfred Morrissey, a Company Senior Analyst in the Market Planning and Forecasting Section, prefiled testimony regarding sales forecasts. Mr. Augustine Camara, Assistant Comptroller for EUA, presented testimony about EUA Service Company charges. Mr. Mark Sorgman, the Supervisor of Revenue Requirements for EUA Service Company, gave testimony on Newport's cost of service study. Mr. James Bonner, the EUA Service Company Supervisor of Rate Design, presented testimony as to rate design. Mr. James Aikman presented the information on the Depreciation Study. Ms. Candace Block submitted testimony on FASB 106. Along with Mr. Settle and Mr. Powderly, John R. Stevens, President and CEO of EUA and Vice President of Newport Electric Corporation, gave testimony at a reopened hearing held at the order of the Commission on September 8, 1992, to further gather information on the transfer of equity rights in Ocean State Power.

The Division of Public Utilities and Carriers and the Department of the Attorney General (hereafter called "Division") presented the testimony of four witnesses. Mr. James A. Rothschild, President of Rothschild Consulting Services, provided testimony on the capital structure, cost of capital, and equity rate of return. Mr. David Nichols, the Tellus Institute, presented testimony regarding class revenue requirement and rate design. Mr. Frank Ackerman, a senior economist with the Tellus Institute, submitted testimony on sales forecasts and revenue attrition. Mr. David Effron, a consultant/CPA, presented testimony on rate base and cost of service.

TEC-RI, an intervener, presented the testimony of one witness, Ms. Susan K. Baggett, an independent consultant and principal in SKB Consulting, who testified on rate design matters, including demand costs.

The Department of the Navy presented testimony of Dr. John Legler, an independent consultant, on matters regarding the cost of capital. Mr. Maurice Brubaker, Vice President of Drazen-Brubaker Associates, presented testimony on utility cost allocation, cost of service and rate design studies.

The State of Rhode Island Department of Economic Development presented testimony from two witnesses: DED's Director, Joseph Paolino, regarding the impact of high electric rates on the reduction or erosion of the industrial base in the Newport service area. Mr. James Mason, a businessman, gave comments on related issues.

The hearings took place during the month of May, 1992 at which time three stipulations (Exh. A, B & C herein) were filed with the Commission. All stipulations were agreed upon by the Company and the Division. The Navy agreed to Stipulation 1, Total Revenue Requirements, but not to Stipulation 2, Rate Class, or to

Stipulation 3, Rate Design. TEC-RI agreed to Stipulation 2 and 3 but did not sign Stipulation 1. DED did not agree to any of the stipulations.

An evening hearing, within Newport's service area, was held on June 4, 1992, at Newport City Hall for the purpose of taking public comment. One member of the public testified at that night hearing.

Rebuttal hearings were held on June 30, 1992 and the Commission made inquiries regarding the storm fund, Ocean State Power, the Company's service to the Navy, the filed Stipulations, other matters and made additional data requests on these items. Initial briefs were due and received by July 27, 1992, and reply briefs were due and received by August 11, 1992.

The Commission, on its own initiative, reopened hearings on September 8, 1992 for the purpose of seeking information on the transfer of Ocean State Power I and II. The Commission heard testimony at it's reopened hearing from Mr. John Natalizia, former President of Newport Electric Corporation, along with Company witnesses, Mr. Stevens, Mr. Powderly and Mr. Settle, regarding Ocean State Power.

Test Year

The Company selected the period of July 1, 1990 to June 30, 1991 as its Test Year. The Rate Year will be from October 1, 1992 to September 30, 1993.

COST OF CAPITAL

Rate of Return

In ratemaking, it is necessary to establish a rate of return to be applied to a Company's rate base. This rate of return is the overall weighted cost of capital. It is derived by establishing the relative amounts of various kinds of capital used by the Company to finance its rate base investment and setting an appropriate cost rate to each component of capital.

The mandate which we have been given by the Rhode Island Supreme Court and the United States Supreme Court in determining a utility's rate of return is twofold:

1. Comparable earnings- this element of the standard requires that the return be commensurate with that earned by enterprises in the same geographical area engaged in similar activities which entail analogous risk.

2. Capital attraction- it is also necessary that the return be sufficient so that the utility can maintain its financial integrity, attract necessary capital, and fairly compensate investors for the risks they have undertaken. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Water Works & Imp. Co. v. Public Service Commission 262 U.S. 679 (1923); Rhode Island Consumers Council v. Smith, 111 R.I. 271, 302 A.2d 757 (1973); Narragansett Electric Co. v. Harsch 117 R.I. 395, 368 A.2d 1194 (1977).

These principles provide a framework for our rate of return analysis which begins with a determination of the appropriate

Stipulation 3, Rate Design. TEC-RI agreed to Stipulation 2 and 3 but did not sign Stipulation 1. DED did not agree to any of the stipulations.

An evening hearing, within Newport's service area, was held on June 4, 1992, at Newport City Hall for the purpose of taking public comment. One member of the public testified at that night hearing.

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Test Year

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capital structure.

Capital Structure

EUA, the parent Company of Newport Electric Corporation, in a prior Division Docket, No. D-89-17 (on 4/5/90), had given assurances that they would bring the equity level up to 40% by March of 1992, two years after its acquisition of Newport. The common equity ratio as of the December filing date was just over 30%. By March 1992, the ratio had reached the 40% level, as EUA made a $9 million infusion of capital and did forego taking any dividends over the two year period. This factor makes it appropriate to use the proforma capital structure. While the Division originally recommended the use of the actual capital structure at the end of the test year, December 31, 1991, it is more appropriate to base the capital structure on the March 1992 level since the equity level should remain at about 40%. Stipulation 1, section 4 specifies that the "actual permanent capital structure will be used to calculate the overall return." We accept Stipulation 1 and find it's treatment of capital structure permissible.

Cost of Capital

In the matter before us now, the cost of debt is not an issue as both Newport and the Division use 10.28% as the cost of long-term debt. This seems to be a reasonable calculation in light of recent cases heard by this Commission, and there is little on the record which would cause further inquiry or disagreement.

Cost of Equity

The Company initially filed for a return on equity of 12.7%, a slight increase from it's present return of 12.5%. In the analysis performed by the Navy's Dr. Legler (Ex. No. Navy-3), a return on equity was calculated to be 12.0%. The Division set a lower equity return, 12.1%, based upon the December, 1991 equity level of 31% but calculated that 11.4% be the return if the proforma capital structure of 40% were applied. As the Commission has explained above, the appropriate capital structure for the proceeding should be based on the actual level of equity, 40%. In Stipulation 1, sections 4 and 5 the Navy and Newport have adopted the Division's position of 11.4%. We accept Stipulation 1 and specifically it's allowed Return on Equity of 11.4% for annualized earnings and for funds used during construction.

COST OF SERVICE

Introduction

Cost of service represents total of the operating expenses, depreciation, taxes and rate of return the Company is allowed to recover through its approved rates. These costs must be representative of ongoing expenses necessarily incurred in providing service to the Company's ratepayers. Re: Providence Gas

Company, Docket No. 1612 (1982) pp. 48.

The Commission accepts Stipulation 1, which is printed in full and noted as Exhibit A herein. It accepts this revenue portion of the proposed increase with the knowledge that the Division engaged in a thorough study of the cost of service. The Commission is troubled and perplexed that Newport would initially file a high increase of almost 11% then, after a short period of time, be willing to reduce it by 60% to a 6.6% increase or $3,660,000.

As the Commission reviews Stipulation 1 and the record, we make note of the fact that it was signed by the Division, Newport Electric Corporation and the Navy. It appears that TEC-RI, while they did not endorse the revenue requirement stipulation, directed its concern primarily to the issue of stranded investment. TEC-RI's goal was to shift some costs from the ratepayers to the Navy and Newport Shareholders. We will deal with this issue later in this order. Regarding the revenue requirements, neither the briefs nor reply briefs make any arguments that the stipulated 6.6% increase is unreasonable or unwarranted.

The Department of Economic Development, an intervener, has remained steadfast in its opposition to any rate increases and has opposed Stipulation 1 as well as the other stipulations. The Department of Economic Development takes a stand, which has public appeal but no basis in law; the imposition of a rate freeze. While the Commission recognizes the present economic hardships facing the Newport service area and the State of Rhode Island, it cannot deny the Company the opportunity to earn a fair rate of return.

We are constrained by the legal precedent. Allowing Newport a fair rate of return on its investment is not ordered simply out of fairness. It is allowed because the United States and Rhode Island Supreme Courts have required that utilities be allowed to earn a reasonable profit. (Narragansett Electric Company v. Harsch, 117 RI 395, 429, 368H.2d.1194, 1213 (1977), New England Telephone & Telegraph Company v. Kennelly, 81 RI 1, 7; 98A.2d.835 (1953), Bluefield Waterworks Improvement Company v. Public Services Commission 262 US 679 (1923)).

A fair profit enables a utility company to maintain its credit, attract investment and, thus, efficiently expand, operate and maintain its existing plant. Ratepayers are the long-term beneficiaries of a well managed company which makes prudent investments.

Based on the record and testimony, the Commission finds the overall revenue requirements agreed to in Stipulation 1 to be reasonable. Although we find the overall revenue requirement to be appropriate, we have the following concerns and comments regarding rate case expenses and the transfer of interests in Ocean State.

Rate Case Expense

Although we have accepted the stipulation pertaining to the cost of service, special note needs to be made of the disproportionately high rate case expense filed by Newport and incurred by EUA and EUA Service. This concern is intensified by the fact that the overcharges replicate those in the recent

Blackstone Valley case.

In the Blackstone Valley Electric Report and Order recently issued by this Commission, the issue of the propriety of Company rate case expenses was of primary concern. In fact, the Commission decided to reopen its public hearings for the express purpose of further examination of rate case expense. We reiterate, as was stated in that report, that "...a critical factor in our examination of all expense items is the severe economic conditions facing this region". This has an impact both in assuring that the Company implements all the cost controls possible as in other areas non-regulated businesses have and that it recognize, especially in these tough economic times, the Company should negotiate the best contracts with employees, vendors and agents.

The Company rate case expenses of concern here are primarily the charges of EUASC, which like Newport Electric Corporation is a wholly owned subsidiary of EUA.

In this docket, there are total estimated rate case expenses of approximately $455,700. This amount excludes any expenses of the Commission and Division and any comparisons and amounts made herein do not include Commission and Division costs. A review of the exhibits on rate case expense (Commission Exhs. 6 & 7) in this docket show the details of the billings and a comparison is made to the rate case expenses allowed for the Company's affiliate in Docket No. 2016. It appears the Commission's concerns in Blackstone are not recognized in Newport's filing. The total cost in Newport's filing of $455,700 is $56,000, more than the $399,627 the Commission allowed for in Blackstone.

We have examined the actual expenses in this Docket. As of May, 1992, the last figures on the record were reported to be $423,339. This does not include legal services for April and May but does include EUASC charges and cost of money billings through May. We estimate an additional $25,000 for EUASC to complete the case (estimate from Company Vice President Larry Settle at the June 30 1992 hearing) and $7,400 for legal fees (40 hours @ 185/hr) for an estimated total Newport expense of approximately $455,700. It is important to point out that no parties filed rebuttal testimony and this case has been stipulated to in all aspects by the Company and the Division, a factor which should result in reduced rate case expense. Despite the difference in size and workload, this Docket appears to have exceeded the prior Blackstone case by more than $56,000.

Comparison to the last rate case filed by Newport Electric Corporation produces a more stark distinction (see Commission Exhibit 7 of Docket No. 1872). It consisted of Legal Fees of $12,142, Cost of Money consultant fees of $23,764, Transcripts and Miscellaneous Costs of $1,805. In those prior filings, the Newport 'in-house staff' was used to prepare most of the filing information; the main areas not handled in-house were Cost of Money and Legal Fees.

As we segregate and examine EUA Service Company costs, some disturbing trends are apparent. Costs are $313,230 through May and are estimated to total $338,230 after adding an additional $25,000 to complete the case and compliance work. This is $71,500 more than the Commission allowed for EUASC in BVE's filing.

As we analyze the total hours as of May, 1992, there are 8,895 man-hours, or about 4.8 man years, of work. We also note the overall overhead amount is 33% of the total cost. The monthly overhead factors ranged from 28% to 69% of direct labor dollars and for three months it was 69%, 66%, and 64%. Most noteworthy of these overhead costs is the high cost of "overall review and coordination", which is calculated to be $56,780. (Ex. No. CDR-16[1] and Company data resp. item Div.2A. pp. 2-56).

Comparisons are a critical methodology for this Commission to use in determining appropriate rate case expense. The Commission has studied the reasonableness of rate case costs based upon the size and scope of Newport's operations and in comparison with other proceedings of similar complexity. We reiterate a standard used in the Blackstone Report adopted by the State of Maine Public Utilities Commission as a general yardstick for measuring what is reasonable as a rate case expense (see In Re: Millinocket Water Company (1985) 70 PUR 4th 383 aff. 515 A2d 749 1986):

1. The novelty and difficulty of the issues presented;

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[1] CDR-16 is a series of Commission data requests made from the bench at the reopened 9/8/92 hearings. The Company's responses were dated September 10, 11, 12 and 14, 1992. Upon a motion at the 9/28/92 Commission open meeting, these responses were put on the record. All parties, except TEC-RI, which could not be reached, did not oppose placing the OSP transfer responses on the record. TEC-RI was not present at the 9/8/92 hearing and did not raise any issues in regard to OSP in any proceeding nor in its' briefs.

2. the customary fee for similar services, including the fees rendered in the relevant market to companies of similar size in matters of similar importance to the client;

3. the amount of money at issue and the results obtained;

4. the extent to which the attorney's or expert's services contributed to the presentation of the case, the conduct of the proceedings, resolution of matters prior to Commission decision, and the Commission's deliberation and decision of the proceeding;

5. whether the utility used negotiation or bidding process, or otherwise considered information concerning the availability, experience, quality and cost of outside attorney and expert service when hiring outside agents;

6. the experience and ability of the attorney or expert. Other factors may also be relevant.

It is also worth noting that utility companies are not constrained, as the Division is, with a fixed cap on the dollars it expends in a fiscal year regardless of the level of activity. In terms of resources, numbers of consultants, attorneys and staff, the utility companies are, in most cases, operating at an unfair advantage. The Company is expected to aggressively work to cut costs, to find the best vendors at the best value and to study other similar utilities rate case management for ways to improve so as not to burden the ratepayers with unnecessary costs.

The Commission is concerned because of the interlocking directorates and shared management that appears to be standard operating procedure to treat affiliate companies as if they have most favored status. There is little evidence which proves there is a deliberate effort to overcompensate Newport's unregulated sister companies; however, we also see no evidence to cut and post-audit these rising costs. As in the Blackstone case, the service contract between Newport and its sister company, EUASC, is questionably an arms length transaction. There is difficulty in justifying the cost and the man-hours, 4.8 man years as of May 1992, as they compare to proceedings of similar complexity involving companies of similar size and scope.

Our major concern as we examine Company rate case expenses is in the area of Service Company costs; however, the area of outside consultant contracts also requires Commission comment. In Docket No. 2016, Blackstone Valley Electric, the lack of effort in negotiating contracts with outside vendors was criticized. In that case and in the matter now before us, there is nothing to show that the contracts for consultants with Management Resources International and Benrose Economic Consultants were subject to either a bid process or any negotiation. The identical issue and entity was addressed in the Report and Order of Docket No. 2016. The Commission hopes that since that report was not issued until mid March, 1992, that services with these consultants had already been retained by the time notice was received of the need to adopt better methods to get the best value for services. We remind the Company of the effort EUASC undertook (and spelled out in the Blackstone Valley Electric Report and Order, PUC 13877 p. 46, March 1992) in managing its legal costs: it undertook a study of other vendors, investigated all of its options including an in-house program, chose an expert familiar with its operations, negotiated a contract based upon volume, increased the quality of service and importantly reduced its costs by one third.

We feel the Company can, without sacrificing quality, find methods to control rate case expenses. We will continue to audit these costs, especially EUASC charges, to assure the ratepayers get the best value possible. Rate case expenses have grown out of control, and if EUASC affiliates do not take steps to control expenses, this Commission will. This acceptance of the revenue stipulation is in no way intended to endorse the filed rate case expense nor is it deemed to suggest that these costs are reasonable.

Transfer of Ocean State Interest

A matter of considerable attention by the Commission in this docket is that of the transfer of the Company's now highly profitable asset; a right of ownership interest in Ocean State

Power (OSP).[2] The Commission has examined this issue making numerous record requests and reopening the hearings for the sole purpose of gaining a better understanding of Newport's upstream transfer of OSP for no value to an unregulated arm of the parent corporation, EUA. The Commission continued this inquiry after the Division agreed to stipulate to all portions of this docket and thus halted discovery, cross-examination, or further inquiry into substantive matters in this case.

The value of Newport's interest in Ocean State Power came to the attention of the Division and to the Commission in Division Docket D-89-17, Newport Electric Corporation's Application to Issue and Sell $8,000,000 of First Mortgage Bonds filed October 6, 1989. However, it was not until the instant case that the Commission first became aware that this asset was transferred from Newport Electric Corporation, the regulated utility, to EUA Ocean State Power, an affiliate of EUA, the parent corporation, without any compensation.

There are some facts which are not in dispute and are evidenced in the voluminous record (most of which was supplied on the day of the reopened hearing and at the hearing itself). In order to understand the actions that took place and their

[2] Ocean State Power is a 500 megawatt, combined cycle, gas-fired electric generation plant located in Burrillville, Rhode Island. The facility consists of two separate phases, each 250 megawatts in size, known as OSP I and OSP II. The two phases were permitted jointly but constructed separately, although they share numerous and substantial components (i.e. water intake structure and water pipeline, natural gas pipeline, water treatment facilities, administration building, waste disposal system and other elements).

significance, one must have knowledge of the timeline of the history and development of the Ocean State project and how it relates to the asset transfer and Newport Electric's own sale from NECO Enterprises to EUA. The Commission took great pains to obtain a clear record as to the timing of these events despite the Company's initial lack of cooperation in providing any answers, let alone clear and precise ones.

The record shows the following sequence of events:

November, 1984:

Newport Electric enters into a memorandum of understanding between a consortium of firms interested in either developing a power generation project or purchasing electricity from such a project (CDR 16).

November, 1984:

Newport Electric Corporation makes first payment toward the Ocean State Power Project in the amount of $2,900. From this point to August of 1989, Newport Electric continues to make payments three to seven times per year in various amounts. The payments total $654,421.53 (Exh. NEC-R8).

October, 1988:

The Rhode Island Energy Facility Siting Board (EFSB) approves the Ocean State Power Project and grants the license for its construction.[3] The Power Sales Contracts which are agreements by individuals or firms to purchase the electricity to be generated by the power plant are certified to be in place and binding during the EFSB hearings.

December, 1988:

NECO Power Corporation, a subsidiary of Newport Electric Corporation, formally acquires a right of ownership interest of 4.9% in the Ocean State Power Project (T. 9/8/92, p. 41, 43).

December, 1988:

Newport Electric Corporation signs an equity contribution support agreement which guarantees payments to Ocean State Power by NECO Power Corporation, its' wholly owned subsidiary (ibid, p. 41).

December, 1988:

Construction financing is obtained for OSP I. Newport Electric Power Corporation is a signatory (ibid, pp. 59

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[3] The Commission takes administrative notice of the proceeding before the EFSB in Docket #SB-87-1.

& 60).[4] Joint owners are refunded the early contributions to the project as these costs are covered in the construction financing. Newport Electric Corporation receives $510,188 (Ex. NEC-R8).

July, 1989:

NECO Power Corporation changes its name to Newport Electric Power Corporation. It remains as a wholly owned subsidiary of Newport Electric Corporation, the regulated utility (ibid, p. 45, 46).

September, 1989:

Construction financing for OSP II is granted (ibid, p.62).

March, 1990:

Eastern Utilities Corporation (EUA) purchases Newport Electric Corporation from NECO Enterprises (ibid, p. 44).

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[4] The transcript on pages 59 and 60 reflect that Newport Power Corporation signed the construction financing agreement. The witness (Settle) answered this question from memory without consulting any records. This same witness previously stated on pages 46 & 47 that Newport Power Corporation was created in July of 1989 by changing the name of NECO Power Corp. to Newport Power Corp. This company, regardless of its name, was a wholly owned subsidiary of Newport Electric Corporation, the regulated utility in December of 1988. The important point here is the signatory to the construction financing documents and, therefore, the party to this project was an affiliate of Newport Electric Corporation, the regulated utility, as confirmed in the transcript on page 60, lines 2 through 6, in response to a question asked by the Chairman.

July, 1990:

Newport Electric Corporation's Board of Directors approves a motion to transfer their right of ownership interest in the Ocean State Power Project to EUA Ocean State, a wholly owned subsidiary of EUA (ibid, p. 13 & p. 45).

December 31, 1990:

OSP I is declared operational (T. 9/8/92, p. 50). OSP, therefore, qualified for $12.2 million Investment Tax Credits awarded by federal legislation.[5]

December 31, 1990:

Documents finalizing the transfer of Newport Electric Corporation's right of ownership interest in the Ocean State Power Project to EUA Power are signed, finalizing the transfer (ibid, p. 47).

November, 1991:

OSP II is declared operational (ibid, p. 67).

It became clear during the hearings that, in addition to the ownership interest, Newport Electric Corporation had a contract to purchase capacity and energy from Ocean State Power. These two contracts were separate and, although Newport "gave up its equity

[5] See footnote 3.

ownership and did maintain its right to purchase five percent of the output of the energy from the plants." (Stevens - T. 9/8/92, p. 35).

The Company's position in its data and record responses and at the reopened hearing is that Newport's interest in Ocean State Power was worthless as the project was highly risky and it could not raise the $11 million capital needed. According to Company witness Stevens, "We had a Company here (Newport) that couldn't finance its day-to-day operations, let alone an $11 million equity investment." (Stevens - ibid, pp. 19 & 20). Further, he attests that there were no other investors ready and willing to purchase the asset. Mr. Stevens insists a complicating factor in any sale is that, under the terms of the ownership agreement, the other joint owners had the right of first refusal for any share that was to be sold. Mr. Stevens postulated that other joint owners' interest would be served by letting Newport default and then taking the 4.9% share for the $11 million with no premium.

The Commission differs with the Company's assessment of this situation. An examination of the record shows that there was sufficient information available to, and known to, the Company at the time of the transfer to reasonably project the success of the project.

Secondly, the right of ownership interest was an asset with an intrinsic value and a value can be ascribed and should have been paid to Newport Electric Corporation for the transfer of this asset. The Commission notes that at the reopened hearing (T.

9/8/92, pp 87-95) the managers and Board of Directors of Newport Electric Corporation and Newport Electric Power Corporation are, with one exception, employees of EUA or one of its other affiliates. While there is nothing wrong per se with interlocking directorates, in this case it gives rise to question the objectivity of those individuals when they are forced to choose between the interests of the parent company and the regulated utility.

The Commission's position is taken after a close review of the record of this case and chronology of events. In particular, one must integrate the development of the Ocean State Power Project with the transfer of the 4.9% right of ownership interest and the sale of Newport Electric Corporation from NECO Enterprises to EUA.

In considering the interplay of these events, one must be mindful of the enormous task of developing an electric power generating facility. To be successful, a project needs a wide variety of components including a power sales contract, site control, site approval, firm long-term commitment of fuel supply, fuel delivery commitments, fuel delivery infrastructure, firm long-term water supply, environmental permits, siting license, local zoning approval, construction financing, equity commitments, building permits, and a number of other components. In fact, Ocean State Power had to get permit approvals from 34 separate agencies, some having jurisdiction over multiple permits.[6]

Due to the fact that Ocean State Power planned on using

[6] [6] See footnote 3.

natural gas from Alberta, Canada as its fuel, the project needed an export license from the Canadian National Energy Board and a U.S. Gas Import Authorization from the Federal Economic Regulatory Administration. Additionally, this project needed approval of the Power Sales Contracts and an Environmental Impact Statement from the Federal Energy Regulatory Commission.

Clearly, this project was a very speculative venture during the early years of its germination. The financial contributions made to this project in the early stages to cover development costs were offered with great risk that they would ever be recovered. In fact, Company witness Stevens attests to this fact in his testimony by stating, "These dollars are purely at risk, and I think all of us who were in that deal understood that there was no rate base, there was no hope of rate recovery, and throughout the time period, until we obtained permanent financing, construction financing, when the banks came in and took out the people who contributed the money, up until the time the plant was licensed, we made prorata contributions." (T. 9/8/92, p. 54).

Newport Electric signed a memorandum of understanding for this project in November of 1984 and Phase I was declared in service six years later on December 31, 1990. In fact, the memorandum of understanding references a "Vermont Combined Cycle Project" (CDR 16) implying the original site considered for this project was in the State of Vermont!

This summary is presented to highlight two important points. First, during the early stages of the project when the risk was natural gas from Alberta, Canada as its fuel, the project needed an export license from the Canadian National Energy Board and a U.S. Gas Import Authorization from the Federal Economic Regulatory Administration. Additionally, this project needed approval of the Power Sales Contracts and an Environmental Impact Statement from the Federal Energy Regulatory Commission.

Clearly, this project was a very speculative venture during the early years of its germination. The financial contributions made to this project in the early stages to cover development costs were offered with great risk that they would ever be recovered. In fact, Company witness Stevens attests to this fact in his testimony by stating, "These dollars are purely at risk, and I think all of us who were in that deal understood that there was no rate base, there was no hope of rate recovery, and throughout the time period, until we obtained permanent financing, construction financing, when the banks came in and took out the people who contributed the money, up until the time the plant was licensed, we made prorata contributions." (T. 9/8/92, p. 54).

Newport Electric signed a memorandum of understanding for this project in November of 1984 and Phase I was declared in service six years later on December 31, 1990. In fact, the memorandum of understanding references a "Vermont Combined Cycle Project" (CDR 16) implying the original site considered for this project was in the State of Vermont!

This summary is presented to highlight two important points. First, during the early stages of the project when the risk was greatest, ratepayers of Newport Electric Corporation were contributing dollars to the project. These payments started in 1984 and continued until 1989.

Secondly, as a project moves forward in time, and critical components or thresholds are achieved, the risk associated with the project reduces. The further along in time, the closer to completion, the lower the risk becomes. It is the Commission's opinion that on December 31, 1990, when the right of ownership interest was transferred from Newport to an unregulated affiliate of EUA by a Board made up of employees of EUA (with one exception), there was no risk associated with OSP I and comparatively minor risk to the successful completion of OSP II.

To recapitulate, on December 31, 1990, at the time of the transfer, the record reflects the following:

* Binding power sales contracts were in place for both OSP I and OSP II.[7] This legal document provided for the sale of the capacity and energy to be generated by the project at levels that support the overall investment in the project.[8]

* The Federal Energy Regulatory Commission had given its approval of the Power Sales Contracts.[9]

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[7] See footnote 3

[8] See footnote 3

[9] February 8, 1987, FERC Docket #ER 87-23-000

* The National Energy Board of Canada had approved the Gas Export and Transportation Authorization for both OSP I (approved July, 1988) and OSP II (approved July, 1989).[10]

* The Rhode Island Energy Facility Siting Board had given approval for the license to site and construct the facility (October, 1988).[11]

* The Environmental Impact Statement was completed for the project on March 4, 1988, in full compliance with the requirements and standards of the National Environmental Policy Act.[12]

* The project had obtained all necessary environmental permits from the Rhode Island Department of Environmental Management (DEM) including[13]:

    - a Prevention of Significant Deterioration permit (PSD or Air Quality Permit)

    - a "401" permit for withdrawal of 4.4 million

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[10] See footnote 3

[11] see footnote 3

[12] see footnote 3

[13] See footnote 3

gallons per day (mgd) of water for cooling purposes.

- DEM approval of the on-site wastewater clarification system.

- certification that the project conformed with the requirements of the Rhode Island Wetlands Act.

- fuel oil storage permit.

- approved oil spill prevention and countermeasure plans.

- individual sewage disposal system (ISDS) approval.

* The pipeline to carry the cooling water for both OSP I and II was approved by DEM, in place and operational.

* The pipeline to carry natural gas to the facility for both OSP I and OSP II was approved by DEM and FERC, in place and operational.

* Firm long-term (20 year) natural gas contracts for the

fuel supply for OSP I and OSP II were in place.[14]

* Firm long-term contracts to transport the natural gas over various interstate and international pipelines were in place for OSP I and OSP II.[15]

* The construction financing for OSP I (ibid, pp. 59 & 60) and OSP II (ibid, p.62) were in place.

* The contract for construction of OSP II was in place.

* OSP I was declared operational on December 31, 1990 (ibid, p. 50).

The Commission notes in particular the right of ownership interest in Ocean State Power was legally transferred on the same day that OSP I was declared operational. Therefore, there was no longer any risk associated with OSP I.

OSP II had all approvals, certificates and permits at this time. Construction financing for OSP II was in place. Many major components which would be shared by both OSP I and OSP II were built and operational. The contractor for OSP II was in place, fully deployed and experienced in building an exactly similar power house. In the Commission's opinion, there was little, if any, risk

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[14] see footnote 3

[15] see footnote 3

associated with OSP II at the time of transfer.

The runner had cleared all the hurdles. He was beginning his lean into the finish line tape. He was about to win the gold medal. With the stroke of a pen, the color and name of his uniform changed. A different party, other than the one who exerted and sweated through the whole race, would be the recipient of the gold medal.

A fully licensed, fully permitted, fully sited, fully financed, 250 megawatt operational power plant, with another 250 megawatts under construction, certainly has value. Today, when objection arises to the siting of seemingly every energy facility, every street or road project, every airport, every waste facility, group home, or playground, a project in the position of Ocean State Power on December 31, 1990 not only had intrinsic value, it had true economic value.

The successful completion of OSP I and the virtual success of Phase II extends to a high probability of financial success as well. The record contains a number of facts that lead to the assignment of a high probability of financial success. They include:

* The Federal Energy Regulatory Commission (FERC), in an unusual and unique move, had approved 115% of the FERC generic return on equity for OSP 1 (ibid, p. 116).

* There was no reason to believe that FERC would not treat OSP II in a similar manner and approve the same 115%

return.

* The Power Sales Contract was in place and supported the overall investment in the project.

* For OSP II, all the purchases of power from the project were equity owners (ibid, p. 78).

* Ocean State Power stood to earn additional profits as the availability factor for the plant increased (ibid, p. 70).

* Ocean State Power had FERC approval for immediate recovery of all maintenance expenses (ibid, p. 71). Owners, therefore, had the incentive and wherewithal to maintain a high availability factor.[16]

* OSP I was certified operational on December 31, 1990 thus qualifying for $12.2 million in Investment Tax Credits.

There was significant evidence in December of 1990, even in July, 1990, that Ocean State Power would be a highly successful and financially profitable venture. EUA, as a joint owner and participant in this project from 1984, had intimate knowledge of

[16] The availability for the combined project has been 96% or 97% (ibid, p. 70).

the financial prospects of Ocean State Power. They had been a major player in the project almost from its inception. It had long-term power contracts with OSP I and OSP II. EUA had followed closely the FERC proceedings where OSP I has granted the unprecedented 115% rate of return. EUA was aware on a daily basis of the construction activity, permit status and Investment Tax Credit prospects.

In fact, Mr. Stevens himself testified to his true belief in the benefit of this project. Prior to his employ at EUA, he worked for Boston Edison Company, a retail electric utility in Massachusetts. Boston Edison purchased power from OSP I and in referring to this contract Mr. Stevens stated, "I knew a little before that Boston Edison put a quarter of a million dollars. I know because I signed the check because I thought it was a good idea for New England." (T. 9/8/92, p. 53, 54).

Further evidence that EUA was convinced this project was going to be financially profitable is contained in the EUA Annual Report for 1990. This document (Ex.CDR-15) states on page 12, "Besides further diversifying our sources of energy, our investment in EUA Ocean State should provide our shareholders with a premium return".

The avalanche of evidence to support the Commission's opinion continues with the following facts. EUA claims there were no investors willing to purchase this asset. However, the Board made no effort to seek a buyer. Under testimony, Mr. Powderly, President of Newport Electric Corp., stated:

* Newport did not ask any of the other equity owners of

Ocean State Power if they were willing to purchase Newport's share (T. 9/8/92, p. 75 & 76).

* Newport did not ask any other utility if they were interested in purchasing Newport's share of interest in Ocean State Power (ibid, p. 76).

* Newport did not ask any other private investor or consortium of investors if they were interested in purchasing Newport's share of interest in Ocean state Power (ibid, p. 76).

In fact, Mr. Stevens was quite blunt during the reopened hearing on this issue when he stated, "I look around and say, well, who might be interested in buying this thing, and I have to admit that this is pretty much hindsight in that this is not a consideration that we gave much or any really active consideration to in the middle of 1990." (ibid, p. 18 & 19).

The Commission, in its examination of the record, feels that there was sufficient information available to and known to the Company at the time of transfer to reasonably project the success of the project and thus ascribe a value to the Ocean State interest. The determination as to its exact market value at the time of transfer may never be known with certainty. This factor, however, is due to the laxity or unwillingness of the new EUA appointed managers to take any steps to seek a buyer or investor.

The failure of Newport management, or the Board, to take any steps to find a buyer or determine the value of this interest, estops the Company from claiming there was no value and there was no interested buyer. Is it not good business judgement to at least consider that someone else might be willing to purchase it? It should have been at least offered to the other Ocean State Power partners, because the profit from that sale would have benefitted the ratepayers.

The Commission finds that a value should be imputed for Newport's transfer of its Ocean State Power partnership interest. To determine a value, we look to the testimony of John Natalizia, Newport's President prior to the acquisition of Newport by EUA Corporation, on this matter in Division docket D-89-17 (Exh. R-7).[17] Mr. Natalizia explained that in 1989 Newport did not have the equity capital that would be needed in a year or so for its partnership contribution for the first Ocean State Power unit, and therefore he ". . . would recommend that we find another investor to step in our shoes and take us out of there at a profit and obviously keep that profit certainly within Newport Corporation's structure." (NEC Exh. R7, T. 11/2/89, p. 35).

Mr. Natalizia, in response to questioning, described a methodology to be employed to calculate a value of the Ocean State Power interest. He explained that the 115 percent allowed equity

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[17] This testimony took place in 1989. The purpose of this docket was to review Newport Electric Corporation's financial condition and, in particular, to review Newport's debt to equity ratio.

return had a value when leveraged by financing through a utility holding company's normal capital structure. This value stems from the fact that the utility's capital structure is approximately 50% debt and 50% equity with each component carrying a capital cost at a rate lower than the 115% equity returned allowed by the Federal Energy Regulatory Commission ("FERC") for the Ocean State Power units. The value being somewhere between the actual capital costs of the utility holding company and the equity returned allowed (Id. pp. 48-49). He testified, however, that he had not done this calculation. The Commission notes that Mr. Natalizia was brought back to testify in the instant docket. Even with the availability of Mr. Natalizia, Newport Electric did not question the methodology he described in 1989 even after he repeated it again from the witness stand (T. 9/8/92, pp. 175 through 179). Newport chose instead to spend some time to certify the fact that Mr. Natalizia was no longer under the employ of Newport Electric and, in fact, he is receiving payments from EUA stemming from the settlement of legal action he brought against EUA when his services were terminated upon EUA's purchase of Newport Electric Corporation from NECO Enterprises.

Despite the Commission making Mr. Natalizia available to Newport, his methodology for calculating a value of the asset is unrefuted. Therefore, the Commission will use this methodology to calculate a value and do so as follows.

The record in this docket notes the equity contribution made by EUA for the Newport partnership interests acquired was $11.2

million (Exh. CDR 13). On the record, we also have the financial statements for the Ocean State Power Units which show the following earnings:

	Ocean State Unit I	Ocean State Unit II
1991--initial year	15.26%	14.02%
1992--to 7/31/92	19.91%	16.46%

Exhibit CDR-13

Based on the above earnings and the fact that FERC has allowed an equity return at 115% of its generic return, we feel that a reasonably expected equity return over the life (20 years) of the existing power sales contracts of Ocean State is 14.50% (this is 115% of an equity return of 12.6%).[18] We must now compare this to the actual capital costs for a utility holding company to determine an estimate of the 'excess earnings potential' and approximate the sales value of the partnership interest. Using a capital structure of 50% debt and 50% equity, an equity capital cost of 13%[19], and

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[18] The 1991 and 1992 returns are identified to show that the 14.5% equity return chosen for our calculation is conservative.

[19] We feel that this is a relatively high equity cost, but will use this to make a very conservative estimate of value to this transaction. We note that the equity return stipulated to by the Company in this docket is 11.4%, and further, note that this Commission has not granted an equity return greater than 12.80% in 1991 or 1992.

long-term debt costs of 9%[20], the overall cost of capital is 11% (50% X 13% plus 50% X 9%). The difference between a 14.5% return earned and an 11% cost of capital is 3.5%. We then apply this 3.5% excess earnings rate to the unamortized investment supported by 11.2% million equity contribution over the next 20 years. The sum of these 'excess earnings' of capital costs is $3,724,000. The present value of these earnings over the next 20 years is $2,188,000 (using a discount rate of 9%--the interest cost rate used to arrive at the overall capital cost of 11%, see above).

The approximate value of the transferred Ocean State Power interest we feel is conservatively estimated to be $2,188,000. A summary of the calculation follows.

[20]We take administrative notice of Public Utilities Division Docket D-92-2, which authorized the permanent long-term debt financing for the two Ocean State Power units. The debt issued was for an overall term of 19 years with three series of notes, each series carrying an interest rate no higher than 8.21%. Once again, we use a 9% interest rate to be conservative in determining a value for the transaction.

Net Present Value of Excess Earnings

Net Present Value of Excess Earnings $2,188,641.67

Discount Rate	9.00%
Earnings Rate	14.50%
Cost of Capital	11.00%
Excess Earnings Rate	3.50%

Equity Investment	$11,200,000.00	
Total Years	20.00	
Straight Line Deprec.	$ 560,000.00	Excess Earnings
1.	$10,640,000.00	$372,400.00
2.	$10,080,000.00	$352,800.00
3.	$ 9,520,000.00	$333,200.00
4.	$ 8,960,000.00	$313,600.00
5.	$ 8,400,000.00	$294,000.00
6.	$ 7,840,000.00	$274,400.00
7.	$ 7,280,000.00	$254,800.00
8.	$ 6,720,000.00	$235,200.00
9.	$ 6,160,000.00	$215,600.00
10.	$ 5,600,000.00	$196,000.00
11.	$ 5,040,000.00	$176,400.00
12.	$ 4,480,000.00	$156,800.00
13.	$ 3,920,000.00	$137,200.00
14.	$ 3,360,000.00	$117,600.00

15.	$ 2,800,000.00	$98,000.00
16.	$ 2,240,000.00	$78,400.00
17.	$ 1,680,000.00	$58,800.00
18.	$ 1,120,000.00	$39,200.00
19.	$ 560,000.00	$19,600.00
20.	$0.00	$0.00
	TOTAL	$3,724,000.00

The Company argues that even if this asset had value, it would not flow to ratepayers but rather to the stockholders of Newport Electric Corporation.[21] The Commission differs. We have examined the record and determine that ratepayers are entitled to receive an appropriate part of the imputed value of the right of ownership interest in the Ocean State Power project.

Shareholders are not inherently guaranteed the appreciated value of utility property. In the case before us we have testimony on the record that the parent company, NECO Enterprises, made an attempt to segregate the Ocean State Power interests in a corporate entity unregulated by this Commission and apart from the rate base. (see T. 9/8/92 pp. 42-44). That move was not acceptable to lenders on the project which needed a more credit-worthy entity, one that was secured with ratepayer cash flow and rate of returns governed by this Commission. We note initial contributions to Ocean State Power were made by Newport Electric Corporation, not NECO

[21] One share of stock exists in Newport Electric Corporation. It is owned by EUA.

Enterprises. Likewise noted in the record (Exh. No. CDR-13) is that reimbursements, dividends and interest paid by OSP after construction financing was secured were made to Newport Electric Corporation not Newport Electric Power Corporation nor NECO Enterprises. It also appears that at the time there was real risk in the Ocean State projects there was very little equity in the Company due to it's general financial difficulties and the ratepayer substantially bore the risk. But for the existence of the ratepayers and the security they gave lenders to sign a equity contribution support agreement (Settle T. 9/8/92 p. 43) and the contributions made via rates Newport would not have been a participant in OSP and it's twenty plus year promised earnings.

The Commission is confronted with two problems. First, this is a value that we know might not be fully realized in an arms length transaction (or it may, perhaps, be even higher).

Secondly, how is the Commission able to force EUA or its unregulated affiliates to repay to the regulated utility any amount?

The Commission considers three options for repayment and its' decision provides a discount from the calculated value in our continued effort to be conservative on this issue.

The three possible avenues for repayment include: to reduce the revenue requirement allowed in the settlement in the instant case; to order Newport to reduce the payments it makes to the EUA Service Company for service rendered; or to eliminate the current deficit in the Storm Contingency Fund.

The first option would not serve ratepayers' interest because it would not provide compensation. The Commission is accepting the revenue requirement contained in the stipulation and does not intend to alter the components of this stipulation. The issue of the transfer of the right of ownership interest in Ocean State Power is a distinctly separate item in this docket.

The second option brings with it the concern that EUA Service Corporation would somehow reduce the amount of services they provide concomitant with the reduction in payments to them.

The third option needs further explanation. Newport Electric Corporation maintains a Storm Contingency Fund as do other electric utilities regulated by the Commission. The purpose of this account is by annual contribution to build up a fund to pay the cost of service restoration resulting from outages brought about by severe weather incidents. As provided in these proceedings, Newport will be making an annual contribution to this fund of approximately $240,000.

Hurricane Bob, in 1991, was a severe and devastating storm. It knocked out electricity service to 100% of the Newport Electric service territory. It took five days and great expense to fully restore power to all of Newport's customers. This effort has left the Storm Contingency Fund with a balance of approximately negative $1.2 million (Newport Exh. 7-B, w/p 3.12). EUA (or its affiliate, other than Newport) paid for the cost of the restoration after the Storm Contingency Fund account was depleted. EUA, in effect, has "loaned" money to ratepayers and will be paid back at the rate of

$240,000 per year (the annual contribution provided in rates).

The Commission orders that the negative balance in the Storm Contingency Fund be eliminated and the balance be brought to zero to repay Newport Electric ratepayers for the transfer of the right of ownership interest in Ocean State Power from Newport to EUA Ocean State. The $240,000 annual payments to this fund shall continue until adjusted by this Commission.

The Commission, in order to gain a better understanding of this issue, became aware at it's June 10, 1992 hearing of the Company's and EUA's filings to the Securities and Exchange Commission and made data requests (CDR-10) for copies of SEC form U-13-1 and attachments. This information was very useful and the Commission orders that a copy of any and all future SEC filings that name or affect Newport Electric Corporation be forwarded to the Division of Public Utilities and Carriers.

Stranded Investment

The Department of the Navy is Newport Electric Corporation's largest customer, receiving approximately 20% of the Company's service (Powderly Exh. 1, p. 5, line 2). The Navy has, since the last tariff filing, engaged in significant changes as to power usage, as it constructed its own substation and receives transmission voltage, 69 KV, rather than primary service, 13 KV, from the distribution system.

The Navy has sought additional rate relief because of this change which is addressed in the Rate Design section of this report.

TEC-RI has emerged as an opponent of the Navy as they have not signed the same stipulation herein. In the matter of rate class revenue requirements, they have raised the issue of stranded investment. As summarized in its briefs (initial TEC-RI brief pp 2 & 3) TEC-RI asserts that "the change in the method of delivery of service was by a contractual arrangement between the Company and the Navy," that other customers should not be penalized for the impact of this change. They assert (TEC-RI Reply Brief pp 3 & 4) that there is a stranded distribution plant, as consequence of the new Navy substation, which is now the burden of remaining ratepayers.

An interesting policy issue is raised by TEC-RI which pits energy conservation (the Navy) against remaining energy users (TEC-RI). There does not appear to be enough on the record which clearly shows stranded plant, the cost of which has shifted to other ratepayers. For argument, assume that it is the case; the Commission's desire to prevent rate shock and lessen the impact of the Navy going off the distribution system effectively protects other ratepayers. The Commission does not hold that the cost of service should be altered from Stipulation 1 so as to spread the cost of stranded investment to the Navy and Company shareholders.

Conclusions

Based upon the foregoing findings, the Commission approves an increase in revenues of $3,666,000, or 6.6%, for a total cost of service of $59,697,245.

RATE DESIGN

Introduction

Rate design issues were the subject of significant prefiled testimony by the parties and was the prime subject for the intervener, TEC-RI. Company witness James J. Bonner, EUA service Corporation Supervisor of Rate Design, submitted significant prefiled testimony including extensive schedules and workpapers.

Company's Position

For the Company, James J. Bonner, Jr. presented schedules on the design of rates. Exhs. 3, 3-A, 3-B. Two sets of rates were developed to reflect the revenues requested with and without the FASB 106 cost recovery proposed by the Company.[22]

Mr. Bonner noted that the Company's current rates were not based on service voltage level and load size and, therefore, changes were proposed to realign rate classes (BVE Exh. 31 p 8). The residential rate classes were not changed other than to change the tariff numbering.

The general service classes--rates 201 and 301--were realigned to group together customers with similar voltage levels and load size among five rate classes, G-1 G-2 G-4, G-5, and G-6. Other

[22]FASB 106 revenue requirements are an additional $1,249,867 over the base increase of $6,093,664. FASB 106 revenue requirements were requested to be effective on January 4, 1993; this revenue request is deferred by the Commission pending the Commission's generic order on FASB 106, Docket 2045.

changes were made to move the remaining three rate 202 (cooking and refrigeration) customers to rate G-1. Also, the largest space heating customers served under rate 201 and all rate 205 customers (all requirements heating service for commercial property) are being moved to rate G-4. The remaining rate 201 customers are moved to rate H-2, a closed rate class.

The Company proposes to move rate 102 customers (interruptible supplementary heating service rate for customers with electric thermal storage heating and water systems) to rate W-1 and close this rate class. Rate 302 provides service to the Navy under terms of a special contract. The rate was designed based upon providing primary distribution voltage to the Navy; however, in 1990, the Navy placed into service a new substation and now takes electricity at transmission voltage. The new Navy rate is designated C-1 and reflects service to the Navy at transmission voltage. The rate has a time of use rate design with a peak demand charge and an off-peak energy charge for transmission voltage service.

After the realignment and design changes to rate groups, it was necessary to apportion the revenue increase requested among the rate classes to customer charges, demand, and energy charges. For this part of the rate design, Mr. Bonner relied in part upon the results of the allocated cost of service study ("cost study") presented by Company witness Mark Sorgman.

Mr. Bonner's schedules showed that applying the results of the cost study to develop equal returns from all rate classes would result in rate class increases of up to 90% (Exh. 3-B, Sch. JJB-31

p. 24). Due to the extreme impact on rates that would result from applying fully the cost study results, Mr. Bonner modified the class revenue increases to maintain the principle of rate continuity. He described this as, "[r]ate continuity means that changes in rates should be made in a gradual and predictable manner over time while allowing existing customers a reasonable time period in which to respond to the changes made." (Exh. 3, p. 14). The modified revenue allocations he used were as follows:

* one-third weighing to the cost study results;
* two-thirds weighing to an equal percentage increase on current rates;
* a limit on the increase to any one rate class of two times the average percentage increase in net revenues (Exh. 3, p 15).

Mr. Bonner sponsored new tariffs and other changes in the Company's tariffs to reflect:

* A request to cancel their Oil Conservation Adjustment tariff (RIPUC No. 93.1) as Montaup Electric's Oil Conservation Adjustment which is passed onto Newport was canceled by the FERC in a recent rate case.
* New tariffs, designated as T-4 and T-6, which provide for mandatory time of use rates for the Company's larger commercial and industrial customers.
* A change in peak hours for time of use rates for Newport to coincide with the time periods established for

Blackstone Valley Electric. BVE's rates were established using the EUA System loads.

The new time of use rates are proposed to be effective after an eighteen month comparative billing period.

Company's Cost of Service Study

Mark Sorgman sponsored the Company's embedded cost of service study used for this rate filing (Exhs. 4, 4-A, 4-B). He explained that the study serves to assign all costs associated with the utility's operations to the various customer classes. All rate base investment and expenses of operations are assigned to provide "an indication of the cost to serve customers in each rate class and any revenue deficiency or excess which may exist." (Ex. 4, p. 3). As noted above, Mr. Bonner used the cost study results to apportion one-third of the revenue increase.

The cost study was based upon load data for the twelve-months ended June 30, 1991. The major allocation methodologies used in the study were described as follows:

(1) Energy-related items based on kWh at the generator.

(2) customer-related items based upon the number of customers in each rate class.

(3) Capacity and demand-related items used two major allocators: proportional responsibility methodology for production plant, transmission plant and the demand

portion of purchased power; class non-coincident peak demands for all other demand-related items.

The two demand allocators used hourly load data for each of the rate classes. Mr. Sorgman noted that the proportional responsibility methodology is "non-probalistic" and it serves to "distribute a proportionate share of capacity costs to each rate class. The allocation is based on time, duration and demand levels placed on the system by each rate class." (Exh. 4, p 6).

The results of the cost study showed that the Company's overall return of 6.58% was the result of returns from rate classes that ranged from a negative 10% to a positive 67%. Five rate groups showed negative returns: Residential rates 105 (SSI Service) and 103 (Space Heating, a closed rate group), 201SP (General Service Heating, also a closed rate), 102 Controlled Off-peak use, and Lighting Service (Exh. 4-A, Sch MS-1). The 'general' Residential Rate 101 had a return of 5.28% which is reasonably close to the 6.58% overall return earned by the Company as is the All-Electric rate 205 with a return of 7.14%. Above average returns resulted from the General Service rate 201 group, 12.24%, and from the Navy rate 302, 67.42%.

Mr. Sorgman also produced additional cost study results by applying other allocators for certain administrative and general expenses. He utilized demand, energy, and sales allocators to derive five other cost study iterations (Exh. 4-A, Schs. MS-3, MS-4).

Division's Filing

David Nichols of Tellus Institute filled testimony for the Division on the cost study and on rate design matters.

Regarding the cost study, Mr. Nichols felt that more of the "difficult to classify" costs should have been allocated on an energy or demand basis. These costs generally are administrative and general costs whose basis for allocation is often in controversy. In fact, as Mr. Nichols points out, the Company did offer other iterations of cost study results by reallocating certain of these difficult to classify costs by different allocators (see above). In response to Mr. Nichols' request, the cost study was rerun on the basis he recommended for allocating certain administrative and general expenses.

The results of the cost study iterations and composite results were summarized by Mr. Nichols and compared to the results of the Company's study (Div. Exh. 3-A, Sch DN-2). He felt that the Company's study and his iteration had results which "diverge significantly". Although we observe the differences, they do not appear to be very significant when one seeks to determine if a rate group is making some minor or significant contribution or if the return from that class is negative. The general results for each rate group are in the same direction. In fact, Mr. Nichols stated that as "cost-of-service studies are an area in which expert opinion can and often does conflict, I would give some weight to the Company's results as well." (Div. Exh. 3, p 13).

For determining the revenue increases for each rate class, Mr. Nichols used his preferred study results along with the Company's preferred study results, according half the weight to the Company results. This weighing, along with an overall index providing for increases ranging from .85% to 1.15% of the revenue increase, tended to modify the impact and variability of revenue increases among the rate classes.

Mr. Nichols was very critical of the Company's development of unit costs in that the Company's purchased power costs are principally treated as demand related. He maintains that "the bulk of these costs should be energy related." (Div Ex 3, P 19). He notes that since the Company classified two-thirds of purchased power as demand-related, that two-thirds of purchased power costs were reflected in unit demand costs. He argues that since Newport purchases most of its power, the majority of generation costs are energy related, being incurred for baseload capacity, and to classify two-thirds of these costs to demand "suggests that two-thirds of the costs of supplying Newport's needs were incurred solely to meet peak load." (Id. D-2).

Mr. Nichols recommends that a portion of the demand costs be reclassified as energy-related. He uses an allocation of 30% of purchased power costs to demand and the rest to energy to present comparison results; however, he does not specify what adjustment to demand costs he would recommend. His overall analysis is that the unit demand costs developed are too high and the unit energy costs are too low. As a result, he recommends that the Commission reject the unit costs developed by the Company.

For the overall rate design, Mr. Nichols had the following recommendations:

* Revenue increases to rate classes as he proposes in his Schedule DN-5;
* No increase to the residential customer charges, with increases reflected solely in kwh charges;
* For current G-1 customers, the customer charge be equal to the current minimum charge and he accepts the elimination of declining energy charges for this class;
* Demand charges for rate G-2 be limited to a 30% increase;
* General service rates be designed consistent with the recommended 30% increase to demand charges he proposed for rate G-2;
* The mandatory time-of-use rates , T-4 and T-5, be delayed until "there are clear signs of economic recovery."

<u>Energy Council of RI's Filing</u>

Susan Baggett prefiled testimony for TEC-RI on the cost of service and rate design (TEC-RI Exhs. 1, I-A).

Her preferred cost of service study results reflected use of the average of the twelve monthly coincident peaks to allocate the demand portion of purchased power. She noted that this method is used by the Narragansett Electric Company, and that "the Company's Proportional Responsibility method is 'Unduly burdensome to apply and impossible to verify." (TEC-RI Exh. 1 p. 7). Other demand-related costs were allocated using class non-coincident peaks rather than the sum of twelve monthly coincident peaks as applied by the Company. She argued that the distribution system is built to serve the peak rather than average peak load, and the Company's method served to shift demand costs to the large commercial and industrial customers with high year round usage. (Id. p 8).

Ms. Baggett took strong issue with the Company allocating no distribution costs to the Navy by setting the Navy's non-coincident peak allocator at zero. She stated, "The Navy is the largest single customer on the Newport system. It represented 16% of the 1991 annual system peak demand." (Id. p 9).

Her position is that "the Company and the Navy should in some fashion bear the burden of these former distribution costs as a business risk and not pass them immediately on to the other classes." (Id. p 10). She calculated these costs to be approximately $1.2 million and recommended that no more than 20% of this amount be recovered from customers other than the Navy with this filing. Her position reflects that all of the plant formerly serving the Navy is not necessarily needed to provide service to other customers.

Ms. Baggett's revenue allocations were based on her cost study results and the remaining revenue deficiency was allocated using percent of the total cost to serve less purchased power expense.

Navy's Position

Mr. Maurice Brubaker prefiled testimony and cost study results for the Navy (Navy Exhs. 1 & 2). He argues for rates that more closely reflect cost study results so that "customers receive a balanced price signal against which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be induced to use electricity inefficiently in response to the distorted rate design signals they receive."

Mr. Brubaker also took issue with the Company's use of the proportional responsibility method for allocation of transmission costs and the demand component of purchased power. He stated that this method gave far too 'much weight to off-peak loads and not enough to on-peak loads (Navy Exh. 1, p. 12). He notes that neither of EUA's other two utility subsidiaries (Blackstone Valley and Eastern Edison) have used this methodology. His recommendation is that the class contributions to the winter peak (Newport is a winter peaking company) be used to allocate transmission and power supply costs (Id. p 18). He offered a cost of service study utilizing this methodology (Navy Exhs. 2, 4).

The Navy differs with the allocated revenue increase proposed by the Company and other parties and offers revenue allocations based on the full revenue deficiencies by class, and also by giving 1/3 and 1/2 weight to the cost of service study results (Navy Exhs. 2,4). Mr. Brubaker argues for a revenue reduction to the Navy based on the cost of service study results.

Mr. Brubaker stated that he agreed with the redesigned rate C-1 serving the Navy. The new rate provides for a flat-rate,, higher-priced demand charge to replace the current two-block demand charges. The energy charges are changed from a usage basis to on-peak/off-peak rates. The resulting rate design reduces energy charges while increasing demand charges. He takes issue with the tariff language which states that the service to the Navy shall not be used for supplementary, backup or maintenance power purposes as this could preclude the Navy from generating, or purchasing power from another party (Navy Exh. 11 p. 22).

The Stipulations on Rate Design

In this docket, three stipulations have been filed on rate design and class revenue requirements (Joint Exhs. 1, 2, & 3). The first stipulation on the overall revenue requirements has been addressed elsewhere in this report and order. The remaining two stipulations deal with class revenue requirements (Jt. Exh. 2), and detail tariff design changes (Jt. Exh. 3). The Navy does not support the latter two stipulations. We note that Jt. Exh. 3 puts into place the new Navy rate C-1 which rate design features were supported by the Navy in their filed testimony (Navy Exh. 1, p. 22). The other elements of this stipulation deal with the rate design for the other rate classes which does not affect the Navy. Therefore, we conclude that the Navy's only objection is to the revenue requirements for the rate classes, and this is the matter addressed in Jt. Exh. 2.

In Jt. Exh. 2, the parties allocate the overall revenue increase among the rate groups in a manner somewhat similar to what was proposed by the Company in its original filing. There are some changes and, of course, the overall revenue allocated has decreased from 10.98% to 6.60%. The Navy argues that all the cost of service studies support a reduction to the Navy's revenue requirement, and therefore the 3.38% increase allocated to the Navy in Jt. Exh. 2 is inappropriate.

This Commission notes that this is the first cost study submitted by Newport in eight or more years which has appropriate load research data for a meaningful cost of service study. Although the parties have all offered different study results, it is duly noted that all the cost studies presented showed that the Navy was paying significantly more than the average Company return (ten times more by the Company's cost of service study). The Company and Division, who have signed Jt Exh. 2, recognized this in allocating only approximately half the overall percentage increase to the Navy rate class. This makes some movement in the direction of the results of the cost studies, but obviously falls far short of the revenue reduction of $479,000 to $995,000 outlined by the Navy in their Exhibit 4. The parties of Jt. Exh. 2 argue against strict reliance on the cost study results and for a gradual change to class revenue requirements.

In the past, this Commission has generally looked towards the results of cost of service studies to guide rate designs and adjustments to class revenue requirements. We have taken particular note of general revenue increases coupled with the effects of rate design changes to ensure that customer classes will not experience 'rate shock' (i.e. a relatively large, burdensome, and unforseen change to rates). In this docket, the Company proposed to limit class rate increases to no more than two times the overall revenue increase granted. In Jt. Exh. 2, we see this limit continue as five classes, accounting for about 13% of total revenues, will see increases of 10.27% to 12.94%. We must consider the burden of rate shock to these classes if we were to make a more dramatic revenue shift as proposed by the Navy. We also take note of the testimony regarding the cost of past investment in primary service lines to the Navy which now falls upon the other ratepayers. This has an impact in shifting cost away from the Navy.

In the interest of rate continuity and gradualism in rate increases, we will accept the stipulation on class revenue allocations, Jt. Exh. 2. This decision also considers the fact that we have seen only one cost study (that filed in this docket) for Newport over the last five years and the first to have meaningful underlying load research data in eight or more years. We cannot rely on a single study period of one year to impose the impact on ratepayers recommended by the Navy.

Regarding the stipulation on the design of rates, Jt. Exh. 3, we also accept this agreement. As noted above, the Navy also did not sign this stipulation, but the rate design imposed upon the Navy by this agreement has been endorsed by the Navy in its prefiled testimony. We find the other rate design matters in Jt. Exh. 3 to be appropriate.

Other Matters on Rate Design

The Company seeks to cancel its Oil Conservation Adjustment tariff. This was unopposed and the Company stated that the tariff was no longer needed. We concur and approve cancellation of the tariff.

The Company desires to change the peak hours for its time of use rates to parallel those of the EUA system loads. When the peak hours were first set for Newport it was based upon the Company's peak hours for which it had to have enough capacity under contract. The purpose is to provide the appropriate time/price signal so as to shed load at the times the Company must have peak-level contract demand. We are not convinced that the record supports the requested change in peak hour demand to the Company and reject this change.

The Navy seeks to have wording removed from their rate C-1 which prevents the Navy from taking service through this tariff for supplementary, backup, or maintenance power purposes. We will not remove this language at this time. The Company has recently changed service to the Navy from primary service to transmission level service which potentially has created some unused distribution plant. We feel that there should be some inherent responsibility to the Navy to support the plant investment which is made to serve them. If Navy service should change, we would consider making such changes if the parties can bring before us a reasonable settlement on this matter.

Conclusions

The Commission accepts the stipulated agreements of the parties as they apply to revenue requirements, Stipulation 1 (Exhibit A), rate class revenue requirements, Stipulation 2, (Exhibit B) and rate design, Stipulation 3, (Exhibit C).

ORDER

Accordingly, it is

(14039) Ordered:

(1) That the tariff filing made on December 27, 1992 made by Newport Electric Company, is hereby rejected, denied and dismissed;

(2) That Newport Electric Corporation is hereby instructed to file with this Commission forthwith new rates and charges designed to recover for the Company additional annual revenues in the amount of $3,660,000 which provides for a total cost of service of $59,697,245;

(3) That Newport Electric Corporation shall implement any rate increase among and within rate classes in a manner consistent with this Report and Order;

(4) That the rates herein authorized to be filed are to be applied to meter readings taken thirty (30) days and after the date of this Order;

(5) That the ratepayers' accrued liability to the Storm Contingency Fund is eliminated by crediting the Storm Contingency Fund with $1.2 million representing the imputed value of the Ocean

State transfer; further, that the responsibility of the ratepayers towards an accrual of the Storm Contingency Fund Reserve shall be at an annual amount of $240,000; and

(6) That the Company shall act in accordance with all other findings and instructions contained within this Report and Order, including but not limited to: the cancellation of the Oil Conservation Adjustment tariff, maintaining Newport specific peak hour demand times, delaying for two years further implementation of Time of Use rates for larger corporate users, Commission rate design approval should the Navy seek non Newport Electric Corporation power, and a requirement to file copies of any and all SEC filings with the Division of Public Utilities within thirty days after the SEC filing.

DATED AND EFFECTIVE AT PROVIDENCE, RHODE ISLAND THIS 28th DAY OF SEPTEMBER, 1992.

James J. Malachowski, Chairman

Lila M. Sapinsley, Commissioner

Paul E. Hanaway, ~~Commissioner~~

EXHIBIT
Joint 1

APPENDIX "A"

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: NEWPORT ELECTRIC CORPORATION APPLICATION TO CHANGE RATE SCHEDULES FILED ON DECEMBER 27, 1991	Docket No. 2036

STIPULATION OF THE PARTIES WITH RESPECT TO REVENUE REQUIREMENTS

Now come The Division of Public Utilities and Carriers ("Division"), Attorney General of Rhode Island, the Department of Navy on behalf of the Department of Defense and all federal executive agencies (collectively "Navy") and Newport Electric Corporation ("Newport") and state as follows:

WHEREAS on December 27, 1991, Newport, filed with the Commission a request to increase its rates in the aggregate amount of $7,343,531 or an increase of 13% to be implemented in two phases - Phase I which would generate $6,093,664 in additional revenues, an increase of 11%, and Phase II which represents the revenue requirement impact of the Financial Accounting Standard Board Statement 106, accounting treatment of post-retirement benefits other than pensions, which will generate an additional $1,249,867 in revenues, an increase of 2%; and

WHEREAS, on January 21, 1992, the Commission suspended the effective date of said rate schedules until June 27, 1992 in order to conduct an investigation of Newport's proposals; and

WHEREAS, on May 4, 1992, the Commission established Docket No. 2045 for the purpose of conducting a generic investigation of the issues raised by Newport in the aforementioned Phase II filing, and deferred passing upon the merits thereof until a decision is issued in said docket; and

WHEREAS the Division has retained expert witnesses and conducted a thorough and complete investigation of Newport's entire Phase I revenue requirement proposal, and the Navy has retained an expert witness to evaluate Newport's proposed return on equity and overall rate of return; and

WHEREAS the Division, pursuant to its investigation, has recommended that Newport's Phase I request to increase rates be reduced to $3,006,000; and

WHEREAS Newport, the Division, TEC-RI, the Navy, and DED have engaged in settlement discussions with respect to Newport's Phase I revenue requirements; and

WHEREAS the parties hereto have reached a comprehensive agreement fully resolving all matters pertaining to the Phase I revenue requirements pending in this case;

NOW, THEREFORE, the Division, the Navy, TEC-RI, DED, and Newport agree and stipulate as follows:

<u>RATE INCREASE</u>

1. Newport's Phase I rates shall be revised to increase annual revenues by $3,660,000, an increase of 6.6%.

2. The revenue increase provided for above does not reflect the recovery of any costs associated with the proposed Phase II rate increase, and all issues relating to the recovery by Newport of costs to be incurred in connection with Finance Accounting Standard Board Bulletin 106 shall be addressed separately in Docket No. 2045.

3. The revenue increase specified above will provide just and reasonable rates.

QUARTERLY EARNINGS REPORTS

4. For purposes of the calculations contained in the quarterly earnings reports filed with the Commission, commencing with the first report due after implementation of new rates, Newport's allowed return on equity shall be specified as 11.40% and its actual permanent capital structure will be used to calculate the overall return.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

5. For purposes of calculating an allowance for funds used during construction, Newport will use a rate of return on common equity of 11.40%, effective September 27, 1992.

COMPOSITE DEPRECIATION RATE

6. The parties hereto agree that the Commission's order shall incorporate approval of an overall composite depreciation rate of 3.39% for the purpose of calculating depreciation, based upon Newport's test

year plant account balances and its proposed annual depreciation accrual rates for those account balances.

7. Other than as expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any subsequent rate proceeding.

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

9. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or used for any purpose.

Respectfully Submitted,

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS AND ATTORNEY GENERAL OF RHODE ISLAND
By their Attorney,

Julio C. Mazzoli, Special Assistant Attorney General
72 Pine Street
Providence, RI 02903

DEPARTMENT OF NAVY ON BEHALF OF THE DEPARTMENT OF DEFENSE AND ALL FEDERAL EXECUTIVE AGENCIES
By its Attorney,

Audrey J. Van Dyke, Counsel for the Secretary of Defense
200 Stovall Street
Alexandria, VA 22332-2300

Respectfully Submitted,

NEWPORT ELECTRIC CORPORATION
By its Attorney,

David A. Fazzone, Esq.
McDermott, Will & Emery
75 State Street
Boston, MA 02109

May 18, 1992

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EXHIBIT
Joint - 2

APPENDIX "B"

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: NEWPORT ELECTRIC CORPORATION APPLICATION TO CHANGE RATE SCHEDULES FILED ON DECEMBER 27, 1991	Docket No. 2036

STIPULATION OF THE PARTIES WITH RESPECT TO RATE CLASS REVENUE REQUIREMENTS

Now come the Division of Public Utilities and Carriers ("Division"), the Attorney General of Rhode Island, The Energy Counsel of Rhode Island ("TEC-RI") and Newport Electric Corporation ("Newport") and state as follows:

WHEREAS on May 18, 1992, the parties hereto, with the exception of TEC-RI, filed a Stipulation with the Commission which establishes an increase in the annual revenue requirement for Newport of $3,660,000 in the above-entitled matter in regard to what is described therein as Phase I; and

WHEREAS the Division and TEC-RI have retained expert witnesses and conducted a thorough and complete investigation of Newport's proposed rate class revenue requirements; and

WHEREAS Newport, the Division, the Attorney General, and TEC-RI, have engaged in settlement discussions with respect to Newport's rate class revenue requirements to recover said Phase I additional annual revenue requirement of $3,660,000; and

WHEREAS the parties hereto have reached a comprehensive agreement fully resolving all matters pertaining to the resulting rate class revenue requirements pending in this case;

NOW, THEREFORE, the Division, the Attorney General, TEC-RI, and Newport agree and stipulate as follows:

1. Newport's proposed rates shall be revised in accordance with the rate class revenue requirements set forth on Schedule 1 attached hereto to recover an increase in annual revenues of $3,660,000.
2. Other than as expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any subsequent rate proceeding.
3. This stipulation is the product of settlement negotiations. The content of those negotiations shall be privileged and all offers of settlement shall be without prejudice to the position of any party or participant presenting such offer.
4. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not

constitute a part of the record in any proceeding or used for any purpose.

Respectfully Submitted,

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS AND THE ATTORNEY GENERAL OF RHODE ISLAND
By their Attorney,

Julio C. Mazzoli, Special Assistant Attorney General
72 Pine Street
Providence, RI 02903

THE ENERGY COUNCIL OF RHODE ISLAND
By its Attorney,

Paul Ivaska, Esq.
84 State Street
Boston, MA 02109

NEWPORT ELECTRIC CORPORATION
By its Attorney,

David A. Fazzone, Esq.
McDermott, Will & Emery
75 State Street
Boston, MA 02109

May 29, 1992

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NEWPORT ELECTRIC CORPORATION
RIPUC Docket 2036
Rate Design Settlement Proposal
Rate Class Revenue Requirements

	(1)	(2)	(3)	(4)	(5)
	Rate Class	Present Adjusted Net Revenues #1	Proposed Settlement Revenue Increase #2	Proposed Net Revenues [C.2+C.3]	Proposed Percentage Increase on Net Revenues [C.3/C.2]
1.	Rate 101	$14,287,572	$1,091,000	$15,378,572	7.64%
2.	Rate 103	3,750,218	385,000	4,135,218	10.27%
3.	Rate 105	15,459	2,000	17,459	12.94%
4.	Rate 201	15,006,187	862,000	15,868,187	5.74%
5.	Rate 205	1,157,773	83,000	1,240,773	7.17%
6.	Rate 201SP ...	1,011,599	104,000	1,115,599	10.28%
7.	Rate 301	7,055,994	463,000	7,518,994	6.56%
8.	Rate 302	10,488,363	354,000	10,842,363	3.38%
9.	Rate 102	1,967,913	229,000	2,196,913	11.64%
10.	Lighting	742,350	87,000	829,350	11.72%
11.	Total	$55,483,428	$3,660,000	$59,143,428	6.60%

#1 from Workpaper WP.JJB-3, p.26
#2 from Revenue Increase by Rate Class agreed upon at 5/18/92 Rate Design Settlement Meeting.

file: NEC\PUC2036\SFSCH-1.WK1, Rev. 0, By JJB, 19-May-92

EXHIBIT
Joint 3

APPENDIX "C"

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

RE: NEWPORT ELECTRIC CORPORATION APPLICATION TO CHANGE RATE SCHEDULES FILED ON DECEMBER 27, 1991)

Docket No. 2036

STIPULATION OF THE PARTIES WITH RESPECT TO RATE DESIGN

Now come the Division of Public Utilities and Carriers ("Division"), the Attorney General of Rhode Island, The Energy Council of Rhode Island ("TEC-RI") and Newport Electric Corporation ("Newport") and state as follows:

WHEREAS on May 18, 1992, the parties hereto, with the exception of TEC-RI, filed a Stipulation with the Commission which establishes an increase in the annual revenue requirement for Newport of $3,660,000 in the above-entitled matter in regard to what is described therein as Phase I; and

WHEREAS the Division and TEC-RI have retained expert witnesses and conducted a thorough and complete investigation of Newport's proposed rate design; and

WHEREAS Newport, the Division, the Attorney General, and TEC-RI, have engaged in settlement discussions with respect to Newport's rate design to recover said Phase I additional annual revenue requirement of $3,660,000; and

WHEREAS the parties hereto have reached a comprehensive agreement fully resolving all matters pertaining to the resulting rate design pending in this case;

NOW, THEREFORE, the Division, the Attorney General, TEC-RI, and Newport agree and stipulate as follows:

1. Newport's proposed rates shall be revised in accordance with the rate design set forth on Schedule 1 attached hereto to recover an increase in annual revenues of $3,660,000.
2. Other than as expressly stated herein, the acceptance of this stipulation by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any issue in any subsequent rate proceeding.
3. This stipulation is the product of settlement negotiations. The content of those negotiations shall be privileged and all offers of settlement shall be without prejudice to the position of any party or participant presenting such offer.
4. This stipulation is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the stipulation in its entirety, the stipulation shall be deemed withdrawn and shall not

constitute a part of the record in any proceeding or used for any purpose.

Respectfully Submitted,

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS AND THE ATTORNEY GENERAL OF RHODE ISLAND
By their Attorney,

Julio C. Mazzoli, Special Assistant Attorney General
72 Pine Street
Providence, RI 02903

THE ENERGY COUNCIL OF RHODE ISLAND
By its Attorney,

Paul Ivaska, Esq.
84 State Street
Boston, MA 02109

NEWPORT ELECTRIC CORPORATION
By its Attorney,

David A. Fazzone, Esq.
McDermott, Will & Emery
75 State Street
Boston, MA 02109

May 29, 1992

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NEWPORT ELECTRIC CORPORATION
RIPUC Docket 2036
Rate Design
Settlement Proposal

I. Residential Rates

A. Proposed Rates R-1, R-3, and R-4

Allocate proposed increase solely to energy charges. Use present Rate 101, Rate 103, and Rate 106 customer charges as the proposed customer charges for Rates R-1, R-3, and R-4, respectively. Redesign proposed Rate R-4 from present Rate 106 using the same methods shown on Workpaper WP.JJB-3, p. 5. Maintain present Rate 106 peak energy charge to off-peak energy charge ratio for proposed Rate R-4.

B. Proposed Rate R-2

Derive proposed Rate R-2 from proposed Rate R-1 using the same methods shown in Workpaper WP.JJB-3, pp. 2-3. Allocate revenue deficiency to all other rate classes using the same methods shown in Workpaper WP.JJB-3, pp. 2-3.

II. General Service Rates

A. Proposed Rate G-1

Set proposed Rate G-1 customer charge equal to 1.5 times present Rate 201 minimum charge and allocate balance of proposed increase to energy charge.

B. Proposed Rates G-2/G-4 and G-5/G-6

Redesign Rates G-2/G-4 and G-5/G-6 such that the maximum allowable increase to any customer does not exceed twice the Company average increase using the same methods shown on Workpaper WP.JJB-3, pp. 7 and 9.

C. Proposed Rates T-2, T-4, T-5 and T-6

Derive proposed T-2, T-4, T-5 and T-6 from proposed Rates G-2, G-4, G-5 and G-6 such that the maximum allowable increase to any customer does not exceed twice the Company average increase using the same methods shown on Workpaper WP.JJB-3, pp. 8 and 10. Delay the effective date of the mandatory TOU rates, Rates T-4 and T-6, for two years beyond the effective date for all other rates as determined by the RIPUC in its forthcoming Order in this Docket.

D. Proposed Rates A-4 and A-6

Derive proposed Rates A-4 and A-6 from proposed Rates T-4 and T-6 using the same methods shown on Workpaper WP.JJB-3, p. 14, except reduce the proposed Rate A-4 and A-6 Production-Transmission Demand Charges and Distribution Demand Charges proportionately so that the sum of these demand charges equal proposed Rate T-4 and T-6 Demand Charges, respectively.

E. Proposed Rate H-1

Redesign proposed Rate H-1 from present Rate 205 using the same methods shown on Workpaper WP.JJB-3, p. 11. Maintain closed availability.

F. Proposed Rate C-1

Redesign proposed Rate C-1 from present Rate 302 using the same methods shown on Workpaper WP.JJB-3, p. 16. Maintain 4 to 1 peak energy charge to off-peak energy charge ratio.

III. Supplementary Rates

A. Proposed Rate H-2

Redesign proposed Rate H-2 from the Special Space Heating Provision-Limited of present Rate 201 using the same methods shown on Workpaper WP.JJB-3, p. 12. Maintain closed availability.

B. Proposed Rate W-1

Allocate proposed increase on an equal percentage basis to customer charge and energy charge. Close availability.

IV. Lighting Service Rates

A. Proposed Rate S-1

Allocate proposed increase on an equal percentage basis to present Rates 501, 502, 503, and 504 fixture charges.

Navy 1-9-ELEC

Request:

Referring to the direct testimony of Company witness Jeanne Lloyd, Schedule JAL-8, RIPUC No. 2119:

a) Please explain in detail how the Company proposes to allocate pension and OPEB costs in base rates to the customer classes in its proposed allocated class cost of service study in this case.

b) Please provide a detailed explanation of the Company's rationale for recovering pension and OPEB costs in the Pension Adjustment Mechanism via a flat per kWh charge from all customer classes.

Response:

a) This amount is included in Employee Pensions & Benefits, account 926, and is allocated among the rate classes based on the Labor cost included in the operating expense accounts.

b) As indicated in the response to part a), the Test Year pension expense has been allocated to each rate class based upon an appropriate allocation factor and will be recovered from each class through class-specific distribution charges. The cost that will be recovered through the Pension Adjustment Factor will be limited to the amount of actual pension expense incurred during the reconciliation period that is above or below the amount approved for recovery through base rates. In some years, this could be a charge to customers; in other years, this could be a credit to customers. The Company is proposing to recover or refund this amount to customers through a uniform per kWh factor applicable to all customers.

In general, the Company does not object to designing class-specific reconciling factors. In fact, the Company is proposing to implement class-specific transmission adjustment factors as part of its proposal in this rate case. Although it may be appropriate to design class-specific factors to recover or refund reconciled costs based upon similar methodology as the design of the associated base charges, implementing class-specific adjustment factors as part of a reconciliation filing adds an additional level of complexity to the reconciliation process, which generally has a shorter procedural schedule than a general rate case. Because the Pension Adjustment Factor is designed to recover only the amount of expense in excess of, or less than, the Test Year amount, the Company believes that a uniform per kWh charge is appropriate. The Company currently has other reconciling adjustment provisions that utilize a

Navy 1-9-ELEC, page 2

uniform per kWh charge as the mechanism to recover or refund the over- or under-collection of expense, such as the Revenue Decoupling Adjustment factor, the non-by-passable transition adjustment factor and the net metering charge.

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

Navy 1-10-ELEC

Request:

Referring to the direct testimony of Company witness Jeanne Lloyd, Schedule JAL-8, RIPUC No. 2120:

a) Please explain in detail how the Company proposes to allocate property taxes in base rates to the customer classes in its proposed allocated class cost of service study in this case.

b) Please provide a detailed explanation of the Company's rationale for recovering property tax costs in the Property Tax Adjustment Provision via a flat per kWh charge from all customer classes.

Response:

a) This amount is allocated among the rate classes based on the Plant values, at recorded cost.

b) As indicated in the response to part a), the Test Year property tax expense has been allocated to each rate class based upon an appropriate allocation factor and will be recovered from each class through class-specific distribution charges. The cost that will be recovered through the Property Tax Adjustment Factor will be limited to the amount of actual property tax expense incurred during the reconciliation period that is above or below the amount approved for recovery through base rates.

Please see the Company's response to Navy 1-9-ELEC for a discussion of the Company's justification for implementing a uniform per kWh adjustment factor for recovering/refunding pension expense through the Pension Adjustment Factor as that rationale is applicable to the proposed design of the Property Tax Adjustment Factor.

Prepared by or under the supervision of: Howard S. Gorman