nationalgrid

Thomas R. Teehan
Senior Counsel

August 11, 2009

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
Response to Data Requests

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] responses to data requests issued by the Division and the Commission in the above-referenced proceeding. Attached is a listing of the data requests issued to date and designating the responses included in this filing in bold.

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 4065 Service List

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

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 11, 2009
Linda Samuelian Date

National Grid (NGrid) – Request for Change in Electric Distribution Rates
Docket No. 4065 - Service List as of 7/22/09

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The Narragansett Electric Company d/b/a National Grid					
Docket 4065					
Discovery Log					
As of: August 11, 2009					
[C-denotes confidentiality is being sought]					
Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-1	Filed	6/26/2009	O'Brien		Attachments COMM 1-1-3, 1-1-4, 1-1-5, 1-1-7, 1-1-8, 1-1-9 **BULK**
COMM 1-2	Filed	6/26/2009	O'Brien		Attachments COMM 1-2 A-D
COMM 1-3	Filed	6/26/2009	Dinkel		Attachments COMM 1-3 A-B **BULK**
COMM 1-4	Filed	6/26/2009	O'Brien		
COMM 1-5	Filed	7/22/2009	O'Brien/Dinkel		Attachments COMM 1-5 (1-3)
COMM 1-6	Filed	6/26/2009	Dinkel	C-attachment	Attachments COMM 1-6-1 & 1-6-2 **BULK**
COMM 1-7	Filed	6/26/2009	O'Brien		Attachment COMM 1-7
COMM 1-8	Filed	6/26/2009	Dinkel		Attachments COMM 1-8 (A-D) **BULK**
COMM 1-9	Filed	6/26/2009	Dinkel	C-attachment	Attahments COMM 1-9 (1-11) **BULK**
COMM 1-10	Filed	6/26/2009	Dinkel		Attachment COMM 1-10 (hard copy only) **BULK**
COMM 1-11	Filed	6/26/2009	O'Brien		
COMM 1-12	Filed	7/1/2009	Dinkel/Morrissey		Attachments COMM 1-12 (1-2)
COMM 1-13	Filed	6/26/2009	Dinkel		Attachment COMM 1-13
COMM 1-14	Filed	6/26/2009	Dinkel		Attachment COMM 1-14
COMM 1-15	Filed	6/26/2009	Dinkel		Attachment COMM 1-15
COMM 1-16	Filed	6/26/2009	O'Brien		Attachments COMM 1-16 (1-12)
COMM 1-17	Filed	7/6/2009	Pettigrew		
COMM 1-18	Filed	7/14/2009	Pettigrew		Attachments COMM 1-18-1, 1-18-2, 1-18-3, 1-18-4(a) - (d) **Bulk**
COMM 1-19	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachment COMM 1-19
COMM 1-20	Filed	6/26/2009	O'Brien		
COMM 1-21	Filed	6/26/2009	O'Brien		Attachments COMM 1-21 (1-4)
COMM 1-22	Filed	6/26/2009	O'Brien		Attachments COMM 1-22 (1-2)
COMM 1-23	Filed	6/26/2009	O'Brien		Attachments COMM 1-23 (1-2)
COMM 1-24	Filed	6/26/2009	O'Brien		Attachment COMM 1-24
COMM 1-25	Filed	6/26/2009	O'Brien		Attachments COMM 1-25 (1-14) **BULK**
COMM 1-25 (supp.)	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachments COMM 1-25 (1-3)
COMM 1-26	Filed	6/26/2009	O'Brien		Attachment COMM 1-26
COMM 1-27	Pending				
COMM 1-28	Filed	7/6/2009	O'Brien		Attachment COMM 1-28
COMM 1-29	Filed	6/26/2009	O'Brien		
COMM 1-30	Filed	6/26/2009	O'Brien		
COMM 1-31	Filed	6/26/2009	King		
COMM 1-32	Filed	6/26/2009	O'Brien		Attachment COMM 1-32
COMM 1-33	Filed	6/26/2009	O'Brien		Attachment COMM 1-33 (1-3) **BULK**
COMM 1-34	Filed	6/26/2009	Dowd		Attachments COMM 1-34 (1-2) **BULK**
COMM 1-35	Filed	6/26/2009	Dowd		Attachment COMM 1-35 **BULK**
COMM 1-36	Filed	6/26/2009	Dowd		Attachment DIV 2-1 (electronic only)
COMM 1-37	Filed	6/26/2009	O'Brien		Attachment COMM 1-37
COMM 1-38	Filed	6/26/2009	O'Brien		Attachment COMM 1-38
COMM 1-39	Pending				
COMM 1-40	Filed	6/26/2009	Dowd		Attachment COMM 1-40
COMM 1-41	Filed	6/26/2009	Dowd		Attachment COMM 1-41
COMM 1-42	Filed	6/26/2009	Dowd		Attachment COMM 1-42
COMM 1-43	Filed	6/26/2009	Dowd		Attachment COMM 1-43
COMM 1-44	Filed	6/26/2009	Dowd		Attachment COMM 1-44
COMM 1-45	Filed	6/26/2009	O'Brien		Attachment COMM 1-45

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Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-46	Filed	6/26/2009	Dowd		
COMM 1-47	Filed	6/26/2009	Dowd		Attachments COMM 1-47 (1-3) **BULK**
COMM 1-48 (Part 1)	Filed	7/1/2009	Dowd		Attachment COMM 1-48
COMM 1-48 (Parts 2-5)	Filed	6/26/2009	O'Brien		
COMM 1-49	Filed	6/26/2009	O'Brien		Attachments COMM 1-49 (1-5)
COMM 1-50	Filed	6/26/2009	Dowd		Attachments COMM 1-50 (1-38) **BULK**
COMM 1-51	Filed	6/26/2009	Dowd		
COMM 1-52	Filed	6/26/2009	Dowd		Attachment COMM 1-52
COMM 1-53	Filed	6/26/2009	Dowd		Attachment COMM 1-53
COMM 1-54	Filed	6/26/2009	O'Brien		Attachments COMM 1-54 (1-2)
COMM 1-55	Filed	7/14/2009	O'Brien		Attachment COMM 1-55
COMM 1-56	Filed	6/26/2009	O'Brien		
COMM 1-57	Filed	6/26/2009	O'Brien		Attachment COMM 1-57
COMM 1-58	Filed	6/26/2009	O'Brien		Attachment DIV 3-11 (PDF and working excel)
COMM 1-59	Filed	6/26/2009	O'Brien		Attachment COMM 1-59
COMM 1-60	Filed	7/1/2009	O'Brien		Attachment COMM 1-60 (A-B)
COMM 1-61	Filed	6/26/2009	Dowd		
COMM 1-62	Filed	6/26/2009	O'Brien		Attachments COMM 1-62 (1-2)
COMM 1-63	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachments COMM 1-63 (A-F) EXCEL FILES **BULK**
COMM 1-64	Filed	6/26/2009	O'Brien		Attachment COMM 1-64
COMM 1-65	Filed	6/26/2009	O'Brien		Attachments COMM 1-65
COMM 1-66	Filed	6/26/2009	O'Brien		Attachments COMM 1-66 (1-2)
COMM 1-67	Filed	6/26/2009	O'Brien		Attachments COMM 1-67 (1-3)
COMM 1-68	Filed	6/26/2009	Wynter		Attachment COMM 1-68
COMM 1-69	Filed	6/26/2009	Wynter		Attachment COMM 1-69
COMM 1-70	Filed	6/26/2009	Wynter		
COMM 1-71	Filed	6/26/2009	O'Brien		Attachments DIV 4-1 (1-2) **BULK**
COMM 1-72	Pending				
COMM 1-73	Filed	6/26/2009	O'Brien		Attachments COMM 1-73 (1-2)
COMM 1-74	Filed	7/6/2009	O'Brien		
COMM 1-75	Filed	6/26/2009	O'Brien		
COMM 1-76	Filed	7/1/2009	O'Brien		Attachment COMM 1-76
COMM 1-77	Pending				
COMM 1-78	Filed	7/14/2009	O'Brien	C-attachment	
COMM 1-79	Filed	6/26/2009	O'Brien		Attachment COMM 1-79
COMM 1-80	Filed	8/3/2009	O'Brien		
COMM 1-81	Filed	8/3/2009	O'Brien		
COMM 1-82	Filed	7/1/2009	O'Brien		
COMM 1-83	Filed	6/26/2009	O'Brien		Attachments COMM 1-83
COMM 1-84	Filed	6/26/2009	O'Brien		Attachment COMM 1-84
COMM 1-85	Filed	6/26/2009	O'Brien		Attachment COMM 1-85
COMM 1-86	Filed	6/26/2009	O'Brien		
COMM 1-87	Filed	6/26/2009	O'Brien		
COMM 1-88	Filed	6/26/2009	O'Brien		Attachment COMM 1-88
COMM 1-89	Filed	6/26/2009	O'Brien		Attachment COMM 1-89
COMM 1-90	Filed	7/6/2009	O'Brien		Attachments COMM 1-90 (1-2) **BULK**
COMM 1-91	Filed	6/26/2009	O'Brien		Attachment DIV 4-21 (1-2) **BULK**
COMM 1-92	Filed	6/26/2009	O'Brien		Attachment COMM 1-92
COMM 1-93	Filed	6/26/2009	O'Brien		
COMM 1-94	Filed	6/26/2009	O'Brien		Attachment COMM 1-94
COMM 1-95	Filed	6/26/2009	O'Brien		Attachment COMM 1-95
COMM 1-96	Filed	6/26/2009	King		Attachment COMM 1-96
COMM 1-97	Filed	6/26/2009	O'Brien		
COMM 1-98	Filed	7/1/2009	Dowd		

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Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 1-99	Filed	6/26/2009	Gorman		Attachment COMM 1-99
COMM 1-100	Filed	7/1/2009	Gorman		
COMM 1-101	Filed	7/1/2009	Gorman		
COMM 1-102	Filed	6/26/2009	Gorman		Attachment COMM 1-102
COMM 1-103	Filed	6/26/2009	Wynter		
COMM 1-104	Filed	6/26/2009	Wynter		
COMM 1-105	Filed	6/26/2009	O'Brien		
COMM 1-106	Pending				
COMM 1-107	Filed	6/26/2009	O'Brien		Attachment COMM 1-107
COMM 1-108	Filed	6/26/2009	Wynter		Attachment COMM 1-108
COMM 1-109	Filed	6/26/2009	Dowd/Pettigrew		Attachment COMM 1-109
COMM 2-1	Pending				
COMM 2-2	Pending				
COMM 2-3	Pending				
COMM 2-4	Pending				
COMM 2-5	Pending				
COMM 2-6	Pending				
COMM 2-7	Pending				
COMM 2-8	Pending				
COMM 2-9	Pending				
COMM 2-10	Pending				
COMM 2-11	Pending				
COMM 2-12	Pending				
COMM 2-13	Pending				
COMM 2-14	Pending				
COMM 2-15	Pending				
COMM 2-16	Pending				
COMM 2-17	Pending				
COMM 2-18	Pending				
COMM 2-19	Pending				
COMM 2-20	Pending				
COMM 2-21	Pending				
COMM 2-22	Pending				
COMM 2-23	Pending				
COMM 2-24	Pending				
COMM 2-25	Pending				
COMM 2-26	Pending				
COMM 2-27	Pending				
COMM 2-28	Pending				
COMM 2-29	Pending				
COMM 2-30	Pending				
COMM 2-31	Pending				
COMM 2-32	Pending				
COMM 2-33	Pending				
COMM 2-34	Pending				
COMM 2-35	Pending				
COMM 2-36	Pending				
COMM 2-37	Pending				
COMM 2-38	Pending				
COMM 2-39	Pending				
COMM 2-40	Pending				
COMM 2-41	Pending				
COMM 2-42	Pending				
COMM 2-43	Pending				
COMM 2-44	Pending				
COMM 2-45	Pending				
COMM 2-46	Pending				
COMM 2-47	Pending				
COMM 2-48	Pending				
COMM 2-49	Pending				
COMM 2-50	Pending				
COMM 2-51	Pending				

The Narragansett Electric Company d/b/a National Grid					
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Data Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
COMM 2-52	Pending				

The Narragansett Electric Company d/b/a National Grid
Docket 4065
Discovery Log
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Information Request	Status	Date Filed	Witness	CONFIDENTIAL	Attachments
DIV-1-1	Filed	6/26/2009	O'Brien		Attachment DIV 1-1
DIV-1-2	Filed	7/1/2009	O'Brien		Attachment DIV 1-2
DIV-1-3	Filed	7/1/2009	O'Brien		Attachment DIV 1-3
DIV-1-4	Filed	6/26/2009	O'Brien		
DIV-1-5	Filed	6/26/2009	O'Brien		
DIV-1-6	Filed	7/1/2009	O'Brien		
DIV-1-7	Filed	7/1/2009	O'Brien		
DIV-1-8	Filed	7/1/2009	O'Brien		
DIV-1-9	Filed	6/26/2009	O'Brien		Attachment DIV 1-9
DIV-1-10	Filed	6/26/2009	O'Brien		
DIV-1-11	Filed	6/26/2009	Dowd		Attachment DIV 1-11
DIV-1-12	Filed	6/26/2009	O'Brien		Attachment DIV 1-12
DIV-1-13	Filed	6/26/2009	Dowd		Attachment DIV 1-13
DIV-1-14	Filed	6/26/2009	Dowd		
DIV-1-15	Filed	6/26/2009	O'Brien		
DIV-1-16	Filed	6/26/2009	O'Brien		
DIV-1-17	Filed	6/26/2009	O'Brien		Attachment DIV 1-17
DIV-1-18	Filed	6/26/2009	O'Brien		
DIV-1-19	Filed	6/26/2009	O'Brien		
DIV-1-20	Filed	6/26/2009	Dowd		Attachment DIV 1-20
DIV-1-21	Filed	7/1/2009	O'Brien		
DIV-1-22	Filed	7/1/2009	O'Brien		
DIV-1-23	Filed	7/1/2009	O'Brien		
DIV-1-24	Filed	7/1/2009	O'Brien		
DIV-1-25	Filed	7/14/2009	O'Brien		
DIV-1-26	Filed	6/26/2009	O'Brien		Attachment DIV 1-26
DIV-1-27	Filed	6/26/2009	O'Brien		
DIV-1-28	Filed	6/26/2009	O'Brien		
DIV-1-29	Filed	7/14/2009	O'Brien		Attachment DIV 1-29
DIV-1-30	Filed	7/1/2009	O'Brien		
DIV-1-31	Filed	6/26/2009	O'Brien		Attachment DIV 1-31
DIV-1-32	Filed	6/26/2009	O'Brien		Attachment DIV 1-32
DIV-1-33	Filed	6/26/2009	O'Brien		Attachment DIV 1-33
DIV-1-34	Filed	6/26/2009	O'Brien		
DIV-2-1	Filed	7/1/2009	Gorman	C-attachment	Attachment DIV 2-1 (electronic only)
DIV-2-2	Filed	6/26/2009	Gorman		
DIV-2-3	Filed	6/26/2009	Gorman		
DIV-2-4	Filed	6/26/2009	Gorman		Attachment DIV 2-4
DIV-2-5	Filed	6/26/2009	Gorman		
DIV-2-6	Filed	6/26/2009	Gorman		
DIV-2-7	Filed	6/26/2009	Gorman		
DIV-2-8	Filed	6/26/2009	Gorman		
DIV-2-9	Filed	6/26/2009	Gorman		
DIV-2-10	Filed	6/26/2009	Gorman		Attachment DIV 2-10
DIV-2-11	Filed	6/26/2009	Gorman		
DIV-2-12	Filed	6/26/2009	Gorman		
DIV-3-1	Filed	7/6/2009	O'Brien		
DIV-3-2	Pending				
DIV-3-3	Filed	7/6/2009	O'Brien		Attachment DIV 3-3
DIV-3-4	Pending				
DIV-3-5	Filed	7/6/2009	O'Brien		
DIV-3-6	Pending				
DIV-3-7	Filed	8/3/2009	O'Brien		Attachment DIV 3-7
DIV-3-8 (Supp.)	Filed	8/3/2009	Morrissey		Attachment DIV 3-8 (Supp.)
DIV-3-9 (Supp.)	Filed	8/3/2009	Morrissey		Attachment DIV 3-9 (Supp.)
DIV-3-10	Filed	7/6/2009	Morrissey		Attachment DIV 3-10
DIV-3-11	Filed	7/6/2009	Morrissey		Attachment DIV 3-11 (PDF and working excel)
DIV-3-12	Filed	7/6/2009	O'Brien/Morrissey		Attachment DIV 3-12
DIV-3-13	Filed	7/6/2009	O'Brien/Morrissey		
DIV-3-14	Filed	7/6/2009	O'Brien/Morrissey		Attachment DIV 3-14
DIV-3-15	Filed	7/6/2009	Morrissey		Attachment DIV 3-15
DIV-3-16	Filed	7/6/2009	Pettigrew		

The Narragansett Electric Company d/b/a National Grid					
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DIV-3-17	Filed	7/6/2009	Pettigrew		
DIV-3-18	Filed	7/6/2009	Pettigrew		
DIV-3-19	Pending				
DIV-3-20	Pending				
DIV-3-21	Filed	7/6/2009	Pettigrew		
DIV-3-22	Pending				
DIV-4-1	Filed	7/6/2009	Moul		Attachments DIV 4-1 (1-2) **BULK**
DIV-4-2	Filed	7/6/2009	Dinkel		
DIV-4-3	Filed	7/6/2009	Dinkel		
DIV-4-4	Filed	7/6/2009	Dinkel		
DIV-4-5	Filed	7/6/2009	O'Brien		
DIV-4-6	Filed	7/6/2009	Moul		
DIV-4-7	Filed	7/6/2009	Dinkel		Attachment DIV 4-7
DIV-4-8	Filed	7/6/2009	Dinkel		Attachments DIV 4-8 (1-3)
DIV-4-9	Filed	7/6/2009	Dinkel		Attachment DIV 4-9
DIV-4-10	Filed	7/6/2009	Dinkel		
DIV-4-11	Filed	7/14/2009	O'Brien		Attachment DIV 4-11
DIV-4-12	Filed	7/6/2009	Dinkel		
DIV-4-13	Filed	7/6/2009	Moul		
DIV-4-14	Filed	7/6/2009	Moul		
DIV-4-15	Filed	7/6/2009	Moul		Attachment DIV 4-15
DIV-4-16	Filed	7/6/2009	Moul		Attachment DIV 4-16 (1-2)
DIV-4-17	Filed	7/6/2009	Moul		
DIV-4-18	Filed	7/6/2009	Moul		
DIV-4-19	Filed	7/6/2009	Moul		Attachment DIV 4-19
DIV-4-20	Filed	7/6/2009	Moul		Attachment DIV 4-20
DIV-4-21	Filed	7/6/2009	O'Brien		Attachment DIV 4-21 (1-2) **BULK**
DIV-4-22	Filed	7/6/2009	Moul		Attachment DIV 4-22 (1-2)
DIV-4-23	Filed	7/6/2009	Dinkel		Attachment DIV 4-23
DIV-4-24	Filed	7/6/2009	Moul		
DIV-4-25	Filed	7/6/2009	Moul		
DIV-4-26	Filed	7/6/2009	Moul		
DIV-4-27	Filed	7/6/2009	Moul		Attachment DIV 4-27
DIV-5-A	Filed	7/22/2009	Wynter	**C-attachments**	Attachments DIV 5-A (1-3)
DIV-5-B	Filed	7/22/2009	Wynter		Attachment DIV 5-B
DIV-5-C	Filed	7/22/2009	Wynter		Attachment DIV 5-C
DIV-6-1	Filed	7/14/2009	Tierney		
DIV-6-2	Filed	7/14/2009	Tierney		
DIV-6-3	Filed	7/14/2009	Tierney		
DIV-6-4	Filed	7/14/2009	Tierney		
DIV-6-5	Filed	7/14/2009	Tierney		
DIV-6-6	Filed	7/14/2009	Tierney		Attachment DIV 6-6 **BULK**
DIV-6-7	Pending				
DIV-6-8	Pending				
DIV-6-9	Filed	7/14/2009	Tierney		
DIV-6-10	Filed	7/14/2009	Tierney		
DIV-6-11	Filed	7/14/2009	Tierney		
DIV-6-12	Filed	7/14/2009	Tierney		Attachments DIV 6-12 (a) and (d)
DIV-6-13 (a) - (d)	Filed	7/22/2009	Tierney		Attachment DIV 6-13
DIV0-6-13 (e)	Pending				
DIV-6-14	Filed	7/14/2009	Tierney		Attachment DIV 6-14 (hard copy only)
DIV-6-15 (a)	Pending				
DIV-6-15 (b) and (c)	Filed	7/22/2009	Tierney		
DIV-6-16	Pending				
DIV-6-17	Filed	7/14/2009	Tierney		Attachment DIV 6-17
DIV-6-18	Filed	7/14/2009	Tierney		Attachment DIV 6-18
DIV-6-19 (a) - (d) and (f)	Filed	7/22/2009	Tierney		Attachments DIV 6-19 and DIV 6-19-F (1-2)
DIV-6-19 (e)	Pending				
DIV-6-20	Filed	7/14/2009	Tierney		
DIV-6-21	Filed	7/14/2009	Tierney		
DIV-6-22	Filed	7/14/2009	Tierney		
DIV-6-23	Filed	7/14/2009	Tierney		

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Information Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
DIV-6-24	Filed	7/22/2009	Tierney		Attachment DIV 6-24
DIV-6-25	Filed	7/22/2009	Stout		Attachment DIV 6-25 (1-2)
DIV-6-26	Pending				
DIV-6-27	Filed	7/14/2009	Tierney		Attachment DIV 6-27 (working excel included)
DIV-6-28	Filed	7/14/2009	Tierney		
DIV-6-29	Filed	7/14/2009	Tierney		
DIV-6-30	Filed	7/22/2009	Tierney		
DIV-6-31 (a) - (d) and (f)	Filed	7/22/2009	Tierney		
DIV-6-31 (e)	Pending				
DIV-6-32	Pending				
DIV-6-33	Filed	7/14/2009	Tierney		
DIV-6-34	Filed	7/22/2009	Tierney		Attachment DIV 6-34 (1-2)
DIV-6-35	Filed	7/14/2009	Tierney		Attachment DIV 6-35 (c) and (d)
DIV-6-36	Filed	7/14/2009	Gorman		
DIV-6-37	Filed	7/14/2009	Gorman		Attachment DIV 6-37(a)
DIV-6-38	Filed	7/14/2009	Tierney		
DIV-6-39	Pending				
DIV-7-1	Filed	8/3/2009	King		
DIV-7-2	Filed	7/22/2009	King/Pettigrew		
DIV-7-3	Filed	7/22/2009	King		
DIV-7-4	Filed	7/22/2009	Wynter		
DIV-7-5	Pending				
DIV-7-6	Filed	7/22/2009	Wynter/Stout		Attachment DIV 7-6
DIV-7-7	Filed	7/22/2009	Fields		Attachment DIV 7-7 (a) (hard copy only) and (b)
DIV-7-8	Pending				
DIV-7-9	Filed	7/22/2009	Pettigrew		
DIV-7-10	Filed	7/22/2009	King		
DIV-7-11	Filed	7/22/2009	King		
DIV-7-12	Filed	7/22/2009	King		
DIV-7-13	Filed	7/22/2009	King		
DIV-7-14	Pending				
DIV-7-15	Filed	7/22/2009	King		
DIV-7-16	Filed	7/22/2009	Gorman		
DIV-7-17	Filed	7/22/2009	Gorman		Attachment DIV 7-17
DIV-7-18	Filed	7/22/2009	Smithling		Attachment DIV 7-18
DIV-7-19	Pending				
DIV-7-20	Filed	7/22/2009	King		
DIV-7-21	Filed	7/22/2009	King		
DIV-8-1	Pending				
DIV-8-2	Filed	8/3/2009	Wynter		Attachment DIV 8-2
DIV-8-3	Filed	7/22/2009	Wynter		Attachment DIV 8-3 (hard copy only)
DIV-8-4	Filed	7/22/2009	Gorman		Attachment DIV 8-4 (excel)
DIV-8-5	Filed	7/22/2009	Wynter		Attachment DIV 8-5
DIV-8-6	Filed	8/3/2009	Wynter		
DIV-8-7 a-g (no d)	Filed	8/3/2009	Wynter		Attachments DIV 8-7 (a-g, no d)
DIV-8-7(d)	**Filed Herewith**	**8/11/2009**	**Wynter**		Att. DIV 8-7(d)
DIV-8-8	Filed	7/22/2009	Wynter		
DIV-8-9	Filed	8/3/2009	Wynter		Attachment DIV 8-9
DIV-8-10	Pending				
DIV-8-11	Filed	7/22/2009	Wynter		
DIV-8-12	Filed	8/3/2009	Wynter		
DIV-8-13	Filed	8/3/2009	Wynter		
DIV-8-14	Filed	8/3/2009	Wynter		
DIV-8-15	Filed	8/3/2009	Wynter		
DIV-8-16	Filed	8/3/2009	Wynter		
DIV-8-17	Pending				
DIV-8-18	Filed	8/3/2009	Wynter		Attachment DIV 8-18
DIV-8-19	Filed	8/3/2009	Wynter		Attachment DIV 8-19
DIV-8-20	Pending				
DIV-8-21	Filed	8/3/2009	Wynter		
DIV-8-22	Pending				
DIV-8-23	Filed	8/3/2009	Wynter		Attachment DIV 8-23

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DIV-8-24	Filed	8/3/2009	Wynter		
DIV-8-25	Pending	8/3/2009	Wynter		Attachments DIV 8-25 (a-i)
DIV-9-1	Filed	7/22/2009	Pettigrew		
DIV-9-2	Filed	7/22/2009	O'Brien		
DIV-9-3	Filed	7/22/2009	Gorman		
DIV-9-4	Filed	7/22/2009	Gorman		
DIV-9-5	Filed	7/22/2009	Gorman		
DIV-9-6	Filed	7/22/2009	Gorman		
DIV-9-7	Filed	7/22/2009	Gorman		
DIV-9-8	Filed	7/22/2009	Gorman		
DIV-9-9	Filed	7/22/2009	Gorman		
DIV-9-10	Filed	7/22/2009	Gorman		
DIV-9-11	Filed	7/22/2009	Gorman		
DIV-9-12	Filed	7/22/2009	Gorman		
DIV-9-13	Filed	7/22/2009	Gorman		
DIV-9-14	Filed	7/22/2009	Gorman		
DIV-9-15	Filed	7/22/2009	Gorman		
DIV-9-16	Filed	7/22/2009	Gorman		
DIV-9-17	Filed	7/22/2009	Gorman		
DIV-9-18	Filed	7/22/2009	Gorman		
DIV-9-19	Filed	7/22/2009	Gorman		
DIV-10-1	Pending				
DIV-10-2	Pending				
DIV-10-3	Filed	7/22/2009	Gorman		Attachment DIV 10-3
DIV-10-4	Filed	7/22/2009	Gorman		Attachment DIV 10-4
DIV-10-5	**Filed Herewith**	**8/11/2009**	**Gorman**		Attachment DIV 10-5 (1-4) EXCEL files
DIV-10-6	Filed	7/22/2009	Gorman		Attachment DIV 10-6 (excel)
DIV-10-7	Filed	7/22/2009	Dowd		
DIV-10-8	Pending				
DIV-10-9	Filed	7/22/2009	Dowd		
DIV-10-10	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachment DIV 10-10
DIV-10-11	Pending				
DIV-10-12	Filed	7/22/2009	Wynter		
DIV-10-13	**Filed Herewith**	**8/11/2009**	**Wynter**		Attachment DIV 10-13 (1-2)
DIV-10-14	Filed	7/22/2009	Kateregga		
DIV-10-15	Filed	7/22/2009	O'Brien		
DIV-10-16	Filed	7/22/2009	O'Brien		
DIV-10-17	Pending				
DIV-10-18	Pending				
DIV-10-19	Pending				
DIV-10-20	Filed	7/22/2009	Dowd		
DIV-10-21	Filed	7/22/2009	Dowd		
DIV-10-22	Filed	7/22/2009	Dowd		
DIV-10-23	Pending				
DIV-10-24	Filed	7/22/2009	O'Brien		Attachment DIV 10-24
DIV-10-25	Filed	7/22/2009	O'Brien		
DIV-10-26	Filed	7/22/2009	O'Brien		
DIV-10-27	Pending				
DIV-10-28	Filed	7/22/2009	Gorman		
DIV-10-29	Filed	7/22/2009	Wynter		
DIV-11-1	Pending				
DIV-11-2	**Filed Herewith**	**8/11/2009**	**Pettigrew**		
DIV-11-3	Pending				
DIV-11-4	Pending				
DIV-11-5	Pending				
DIV-11-6	Pending				
DIV-11-7	Pending				
DIV-11-8	Pending				
DIV-11-9	Pending				
DIV-11-10	Pending				
DIV-11-11	Pending				
DIV-11-12	Pending				
DIV-11-13	Pending				
DIV-11-14	Pending				
DIV-11-15	Pending				

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DIV-11-16	Pending				
DIV-11-17	Pending				
DIV-11-18	Pending				
DIV-11-19	Pending				
DIV-11-20	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachment DIV-11-20 (1-2)
DIV-11-21	Pending				
DIV-11-22	Pending				
DIV-11-23	Pending				
DIV-11-24	Pending				
DIV-11-25	**Filed Herewith**	**8/11/2009**	**Pettigrew**		Attachment DIV-11-25
DIV-11-26	Pending				
DIV-11-27	Pending				
DIV-11-28	Pending				
DIV-11-29	Pending				
DIV-11-30	Pending				
DIV-11-31	Pending				
DIV-11-32	Pending				
DIV-11-33	Pending				
DIV-11-34	Pending				
DIV-11-35	Pending				
DIV-11-36	Pending				
DIV-11-37	Pending				
DIV-11-38	**Filed Herewith**	**8/11/2009**	**Dinkel**		Att. DIV 11-38 (1-17)
DIV-11-39	**Filed Herewith**	**8/11/2009**	**Pettigrew**		Attachment DIV-11-39 EXCEL file
DIV-11-40	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-11-41	Pending				
DIV-11-42	Pending				
DIV-12-1	Pending				
DIV-12-2	**Filed Herewith**	**8/11/2009**	**O'Brien**		Attachment DIV 12-2 (1-2)
DIV-12-3	Pending				
DIV-12-4	Pending				
DIV-12-5	Pending				
DIV-12-6	Pending				
DIV-12-7	Pending				
DIV-12-8	Pending				
DIV-12-9	Pending				
DIV-12-10	Pending				
DIV-12-11	Pending				
DIV-12-12	Pending				
DIV-12-13	Pending				
DIV-12-14	Pending				
DIV-12-15	Pending				
DIV-12-16	Pending				
DIV-12-17	Pending				
DIV-12-18	**Filed Herewith**	**8/11/2009**	**O'Brien**		
DIV-12-19	**Filed Herewith**	**8/11/2009**	**O'Brien**		
DIV-13-1	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-13-2	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-13-3	**Filed Herewith**	**8/11/2009**	**O'Brien**		
DIV-13-4	**Filed Herewith**	**8/11/2009**	**O'Brien**		
DIV-13-5	**Filed Herewith**	**8/11/2009**	**Walter**		
DIV-13-6	**Filed Herewith**	**8/11/2009**	**Gorman**		Attachment DIV-13-6 EXCEL
DIV-13-7	Pending				
DIV-13-8	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-13-9	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-13-10	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-14-1	Pending				
DIV-14-2	Pending				
DIV-14-3	Pending				
DIV-14-4	Pending				
DIV-14-5	Pending				
DIV-14-6	Pending				
DIV-14-7	Pending				
DIV-14-8	Pending				
DIV-14-9	Pending				

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Information Request	**Status**	**Date Filed**	**Witness**	**CONFIDENTIAL**	**Attachments**
DIV-14-10	Pending				
DIV-14-11	Pending				
DIV-14-12	Pending				
DIV-14-13	Pending				
DIV-14-14	Pending				
DIV-14-15	Pending				
DIV-14-16	Pending				
DIV-14-17	Pending				
DIV-14-18	Pending				
DIV-14-19	Pending				
DIV-14-20	Pending				
DIV-14-21	Pending				
DIV-14-22	Pending				
DIV-14-23	Pending				
DIV-14-24	Pending				
DIV-14-25	Pending				
DIV-15-1	**Filed Herewith**	**8/11/2009**	**Gorman**		
DIV-15-2	**Filed Herewith**	**8/11/2009**	**Gorman**		Attachment DIV 15-2 (1-2)
DIV-15-3	Pending				
DIV-15-4	**Filed Herewith**	**8/11/2009**	**O'Brien**		
DIV-16-1	**Filed Herewith**	**8/11/2009**	**Fields**		Attachment DIV 16-1
DIV-16-2	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-3	**Filed Herewith**	**8/11/2009**	**Fields**		Attachment DIV 16-3
DIV-16-4	**Filed Herewith**	**8/11/2009**	**Fields**		Attachment DIV 16-4
DIV-16-5	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-6	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-7	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-8	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-9	**Filed Herewith**	**8/11/2009**	**Fields**		Att. DIV 16-9 (1-5)
DIV-16-10	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-11	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-12	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-13	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-14	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-15	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-16	Pending				
DIV-16-17	**Filed Herewith**	**8/11/2009**	**Fields**		Attachment DIV 16-17
DIV-16-18	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-19	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-20	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-21	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-22	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-23	**Filed Herewith**	**8/11/2009**	**Fields**		Attachment DIV 16-23
DIV-16-24	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-25	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-16-26	**Filed Herewith**	**8/11/2009**	**Fields**		
DIV-17-1	Pending				
DIV-17-2	Pending				
DIV-17-3	Pending				
DIV-17-4	Pending				
DIV-17-5	Pending				
DIV-17-6	Pending				
DIV-17-7	Pending				
DIV-17-8	Pending				
DIV-17-9	Pending				
DIV-17-10	Pending				
DIV-17-11	Pending				
DIV-17-12	Pending				
DIV-17-13	Pending				
DIV-18-1	**Filed**	**8/11/2009**	**Gorman**		Attachment DIV 18-1
DIV-18-2	Pending				
DIV-18-3	**Filed**	**8/11/2009**	**Gorman**		
DIV-18-4	**Filed**	**8/11/2009**	**Gorman**		
DIV-18-5	Pending				

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NAVY-1-1	Filed	6/29/2009			
NAVY-1-2	Filed	6/29/2009			
NAVY-1-3	Filed	6/29/2009			
NAVY-1-4	Filed	6/29/2009			
NAVY-2-1	Filed	7/22/2009	Gorman, Wynter, O'Brien		Excel attachments
NAVY-2-2	Filed	7/22/2009	Gorman, O'Brien		Excel attachments
NAVY-3-1	Pending				
NAVY-3-2	Pending				
NAVY-3-3	Pending				
NAVY-3-4	Pending				
NAVY-3-5	Pending				
NAVY-3-6	Pending				
NAVY-3-7	Pending				
NAVY-3-8	Pending				

Commission Data Request 1-19

Request:

Please provide a breakdown of all properties sold or transferred from the Company's books since January 2002. For each transaction, please provide a schedule indicating the date the property was sold or transferred, the sales price, the book value at the time of the sale, the gain or loss recorded on the company's books, whether the property sold was included in a rate case filing , and whether the sale or transfer was made to an affiliated company. For each property sold or transferred to an affiliated company, please provide the fair market value at the time of the sale or transfer and provide the work papers in support of the calculation of the fair market value.

Response:

Please see Attachment COMM 1-19 for the requested information. Please note that there are vertical lines in the attachment that cannot be removed. In the interests of getting this response in for review by the parties, the Company is submitting that document here. The Company will recreate the document manually and resubmit a clean copy at a later date.

Narragansett Electric
Properties Sold or Transferred FY2000 - FY2009

Year	Asset	Sold To	Date	Book Cost	Selling Price	Gain	Ferc	In rate base	Intercompany
FY2009	none								
FY2008	none								
FY2007	Land, Providence RI	Robert Moll	Jun-2006	3,574.59	237,499.07	233,924.48	360	Yes	No
	Land, Tiverton RI	The Nature Conservancy	Feb-2007	1,479.40	944,352.00	942,872.60	121	No	No
FY2006	Land, Manhattan and Newbury Street Prov RI	Robert Moll, R&M Builders	May-2005	3,831.83	321,961.82	303,236.75	360	Yes	No
	Land, North Providence	Micheal F Cassani	Nov-2006	485.11	13,900.00	13,414.89	121	No	No
	Land,Portsmouth	Elliot Street Associates	Dec-06	200,000.00	850,000.00	650,000.00	121	No	No
FY2005	Transformers, 4	APC America, INC	Oct-05	29,870.67	31,961.62	2,090.95	368	Yes	No
FY2004	Land, Langdon St Providence	Stanley Dickenson	Jan-04	2,178.09	85,000.00	82,821.91	360	Yes	No
	Land, Langdon St and Leo Ave. Providence	Robert Moll, R&M Builders	Jan-04	1,412.79	221,363.00	219,950.21	360	Yes	No
FY2003	Land, Progress Street Lincoln RI	Norman Beretta	Apr-2002	1,998.72	25,000.00	23,001.28	360	Yes	No
	Land, Charlestown	LL Properties	Mar-2003	443,357.00	1,100,000.00	656,643.00	121	No	No
	Land, Providence	Rhode Island DOT	Sep-2002	15,984.00	15,984.00	0.00	Land Swap with RI	Yes	No
FY2002	Land and Easements, Rome Point North Kingstown RI	State of Rhode Island	Apr-2001	1,049,577.85	0.00	(1,049,577.85)	121 Gift to RI	No	No
	Land, Corner of Prosper and Langdon Providence RI	Quantum Builders	Oct-2001	2,457.57	72,000.00	69,542.43	360	Yes	No
	Land Smithfield	Veronica G. Indelicato	Nov-2001	208.92	1,500.00	1,291.08		Yes	No
FY2001	none								
FY200	None								

On original response, Not on State Filing

Narragansett Electric
Properties Sold or Transferred FY2000 - FY2009

Year	Asset	Sold To	Date	Book Cost	Selling Price	Gain	Ferc	In Rate Base	Intercompany
FY2007	Easement for Northwest Bike Path Johnston RI	State of Rhode Island	Jun-2006	8,105.51	181,715.00	167,109.49	360	Yes	No
FY2005	Easement, North Smithfield RI	Fernando & Teresa Oliveira	Mar-2005	9.32	5,220.00	5,210.68	350	Yes	No
FY2000	Land, Smithfield Ave Lincoln RI	Richard & Ivette Pina	Apr-1999	68.03	6,500.00	6,431.97	350	Yes	No
	Land Taking, Warwick RI	RI Dept of Transportation	Nov-1999	74.44	11,165.00	11,090.56	350	Yes	No
	Amendment to Easement, Southerly Side of Division St, East Greenwich, RI	Amalgamated Financial Group LP	Nov-1999	10,584.65	26,500.00	15,215.35	105	Yes	No

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDAR YEAR 2006

Pursuant to Section [illegible](A) of the Second Amended Stipulation and Settlement Agreement dated October 15, 2004, and approved [illegible] the Commission in Docket 3617, the following is a list of properties that were sold by The Narraganset[illegible]lectric Company during the calendar year 2006:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non Utility
Tiverton	(N[illegible] 2-8, Block 117, Card 15); (N[illegible] 2-8, Block 117, Card 15); (N[illegible] 2-7, Block 117, Card 21); (N[illegible] 2-7, Block 117, Card 24); (N[illegible] 2-7, Block 117, Card 24)	Aug. 10, 2006	$950,000.00	Non Utility
N. Providence	A[illegible], Lot 161	Nov. 20, 2006	$ 13,900.00	Non Utility
Portsmouth	A[illegible]6, Lot 5	Dec. 22, 2006	$850,000.00	Non Utility

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDAR YEAR 2005

Pursuant to Section [illegible](A) of the Second Amended Stipulation and Settlement Agreement dated October 15, 2004 and approved by the Commission in Docket 3617, the following is a list of properties that were sold by The Narragansett Electric Company during the calendar year 2005:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non
Providence	97/133	May 9, 2005	$ 325,000	Utility
South Kingstown	4 Transformers	October 22, 2005	$ 31,962	Utility
Providence	97/Portion of 162 Plat Card #620/91, 92, 93, 94, and portion of lot 90	November 3, 2005	$ 240,000	Utility

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDARY YEAR 2003

Pursuant to Section [illegible](A) of the Third Amended Stipulation and Settlement Agreement approved by the Commission in Doc[illegible] 2930, the following is a list of properties that were sold by The Narragansett Electric Company during th[illegible]lendar year 2003:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non
Providence	)7/861	June 5, 2003	$ 221,000	Utility
Providence	)7/538	September 30, 2003	$ 85,000	Utility
Charlestown	17/186 & 189	March 19, 2003	$1,100,000	Non-Utility

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDAR YEAR 2002

Per Section 1[illegible]3) of the Third Amended Stipulation and Settlement Agreement in Docket 2930, the following [illegible] a list of properties that were sold by The Narragansett Electric Company during the calendar y[illegible] 2002:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non
Providence	Portion of 20/100	Sept. 19, 2002	Land Exchange	Utility *

* TNEC exch[illegible]ed 11,024 sq. ft. of land on the southerly side of the Dyer Street Substation Site for 11,024 sq. [illegible] of RIDOT land (10,628 sq. ft. on the northerly side and 396 sq. ft. on the easterly side o[illegible]e Dyer Street Substation Site).

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDAR YEAR 2001

Per Section 18 (B) 'the Third Amended Stipulation and Settlement Agreement in Docket 2930, the following is a of properties that were sold by The Narragansett Electric Company during the calendar year 1:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non
No. Kingstown	--------	March 23, 2001	Donation	Non Utility (1)
Providence	)7 / 59	Sept. 12, 2001	$72,000	Utility (2)
Smithfield	:3 / 85	Nov. 7, 2001	$1,500	Utility (3)

(1) Undevelop land situated on Narragansett Bay, commonly referred to as Rome Point.
(2) Portion of unused right-of-way from Pawtucket to Admiral Street Substation in Providence
(3) Portion of unused right-of-way from George Washington Highway to the Providence city line.

ANNUAL SALES REPORT FOR

THE NARRAGANSETT ELECTRIC COMPANY

FOR CALENDAR YEAR 2000

Per Section 18 (I) of the Third Amended Stipulation and Settlement Agreement in Docket 2930, the following is a list of properties that were sold by The Narragansett Electric Company during the calendar year 2000:

City/Town	A.P. & Lot	Date of Sale	Sale Price	Utility/Non
Lincoln	7 / 48	Dec. 20, 2000	$25,000	Utility*

*This parcel was part of an unused right-of-way from Lincoln Junction to Hazel Street Substation in Lincoln, Rhode Island.

Commission Data Request 1-25 (Supplemental)

Request:

Please provide all written contracts between the Company and its affiliates. Provide a narrative description of any unwritten contracts between the Company and any affiliate, including all material terms.

Response:

The following borderline agreements are on file with the Federal Energy Regulatory Commission. Eastern Edison Company in Massachusetts and Blackstone Valley Electric Company in Rhode Island were part of Eastern Utilities Associates, which was acquired by New England Electric System, the predecessor to National Grid. Eastern Edison Company was merged into Massachusetts Electric Company and Blackstone Valley Electric Company was merged into The Narragansett Electric Company.

1. Attachment COMM 1-25-1: Service agreement between Massachusetts Electric Company and The Narragansett Electric Company

2. Attachment COMM 1-25-2: Eastern Edison Company and The Narragansett Electric Company Agreement

3. Attachment COMM 1-25-3: Blackstone Valley Electric Company and Massachusetts Electric Company Agreement

Prepared by or under the supervision of: Robert L. O'Brien

Tariff Number 1
Schedule II
Original Page No. 1

System Transmission Service
FORM OF SERVICE AGREEMENT

This Service Agreement dated as of June 17, 1992 is entered into by and between Massachusetts Electric Company ("Company"), a Massachusetts corporation and Narragansett Electric Company ("Customer").

The Company agrees to provide and the Customer agrees to take and pay for Borderline Sales as specified in Appendix A hereto. The applicable rates for the Borderline Sales shall be as provided in the Company's Retail Rates as approved by the Massachusetts Department of Public Utilities and as in effect from time to time. Those rates and Appendix A hereto are incorporated herein and made a part hereof.

This Service Agreement, Appendix A to this Service Agreement, the Company's FERC Electric Tariff No. 1 and the Company's retail rates as approved by the Massachusetts Department of Public Utilities may be amended from time to time as provided in paragraph F of Schedule I of the Company's FERC Electric Tariff No. 1.

The address of the Company for written communication pursuant to this Service Agreement is:

Massachusetts Electric Company
25 Research Drive
Westborough, Massachusetts 01582
Attn: Director of Rates

The address of the Customer for such purpose is:

The Narragansett Electric Company
280 Melrose Street
Providence, R.I. 02901
Attn: Legal

IN WITNESS WHEREOF, the parties have caused this Service Agreement to be executed by their respective authorized officials as of the date first above written.

MASSACHUSETTS ELECTRIC COMPANY

By: [signature]

(CUSTOMER)

By: [signature]

Borderline Sales Specifications:

1. Borderline sales shall be provided on behalf of Customer at the following Delivery Point(s):

   62 George Street, Barrington, RI
   153 George Street, Barrington, RI
   10 George Street, Barrington, RI
   132 George Street, Barrington, RI
   135 George Street, Barrington, RI
   100 George Street, Barrington, RI
   141 George Street, Barrington, RI
   139 George Street, Barrington, RI

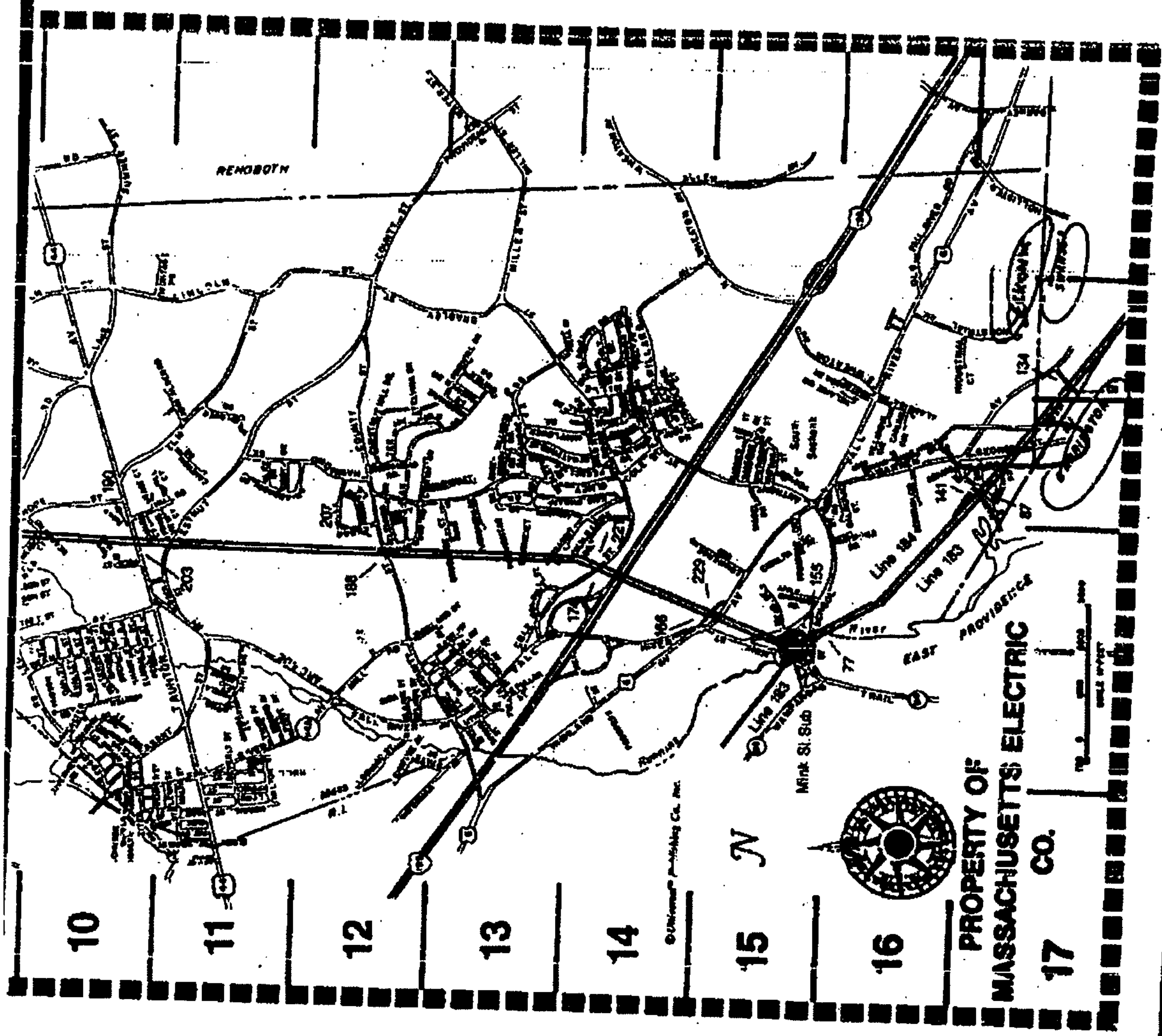
   26 Nye Street, East Providence, RI

2. Applicable Rates:

   R-1

3. Special Provisions Applicable to the Customer (if any):

   None


REHOBOTH
Line 184
Line 183
Mink St. Sub
EAST PROVIDENCE
PROPERTY OF MASSACHUSETTS ELECTRIC CO.
10
11
12
13
14
15
16
17

JUN-12-'92 FRI 14:54 ID:MASS ELEC ATTLEBORO TEL NO:508 226 4088 #152 P01

COMPANY: ROUTE 7401

REPORT: P 1319 MALTA ST

DATE: 7-14-71

SCHEDULE: P 1311 " "

PAGE NO.:

SUBJECT:

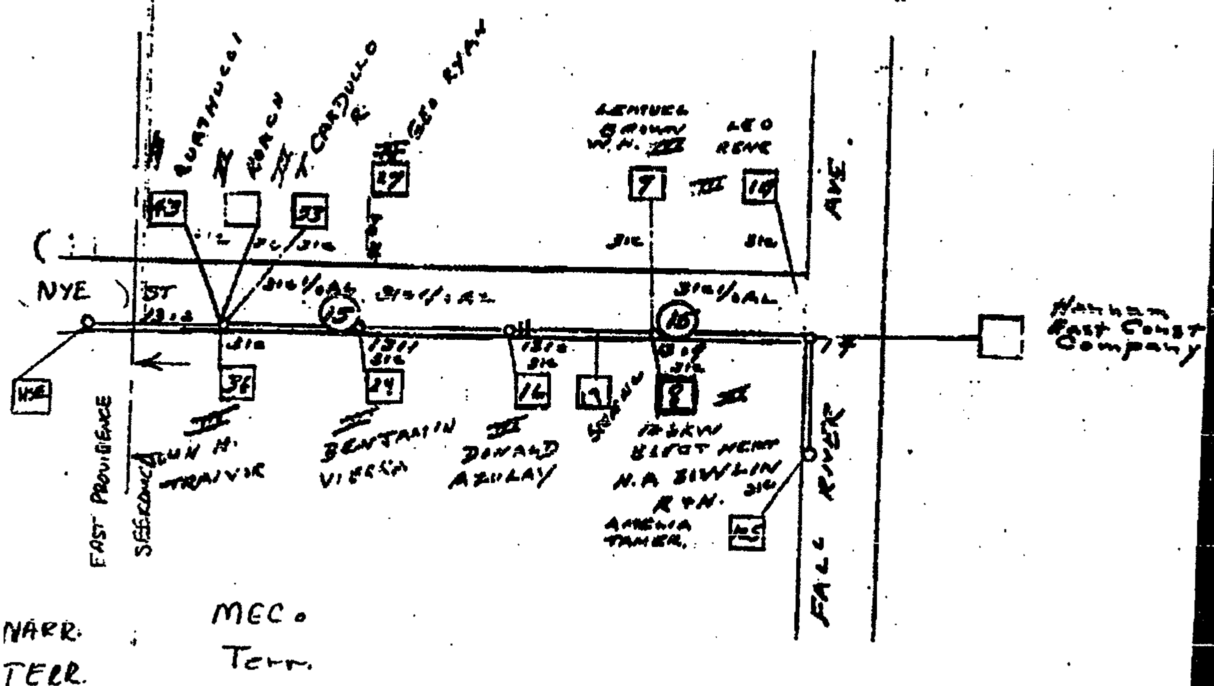
SCHEDULE NO.:

LINE NO.:

PREPARED BY: DN. CHECKED BY: REVIEWED: COLUMN:

15KVA · Co. # 4742
P. 1319 MALTA ST.

15KVA Co. # 6479
P. 1311 MALTA ST.



EUA SYSTEM COMPANY
Eastern Edison Company
PO Box 471 110 Vutberry Street Brockton Massachusetts 02403 Telephone (617) 583-3700

December 1, 1982

Mr. Robert C. Smith, President
Narragansett Electric Company
280 Melrose Street
P.O. Box 1438
Providence, RI 02901

Dear Mr. Smith:

Eastern Edison Company and Narragansett Electric Company have been conducting purchases and sales on a "borderline" basis at locations where their franchise territories adjoin. These purchases and sales have been at the rate of $.03 per KWH, a figure established many years ago.

We suggest that in order to bring this rate to current status that all sales and purchases be at the rates specified herein, as they may be in effect from time to time, subject to all applicable adjustments and surcharges (such as FCA, PPCA, and OCA). For Eastern Edison the rate to be used would be General Service Rate 21, for Narragansett Electric it would be General Service Rate C-2.

This agreement shall remain in effect until terminated by either party giving the other ninety (90) days written notice.

If the foregoing is agreeable to you, please sign below and return one original to me. This letter will provide the necessary authority for each company to begin billing at the specified rate as of January 1, 1983.

Very truly yours,

Allan K. Hamer
Allan K. Hamer
President

Robert C. Smith
Agreed and Accepted

12/7/82
Date

1963 0000

Eastern Utilities
Eastern Edison Company
110 Mulberry Street
P.O. Box 471, Brockton, MA 02403
(508) 580-1213

December 8, 1993

Mr. Robert L. McCabe
President
The Narragansett Electric Company
280 Melrose Street
P.O. Box 1438
Providence, RI 02901-1438

Dear Mr. McCabe:

In the FERC's amnesty order issued July 30, 1993 it made clear that "borderline" sales such as take place between Eastern Edison Company ("Eastern Edison") and Narragansett Electric Company ("Narragansett") under the enclosed letter agreement dated December 1, 1982 are jurisdictional (see page 21 of the Appendix to the order). We plan to file the letter agreement before the amnesty window closes on December 31, 1993.

The December 1, 1982 letter agreement provides that the rate to be charged by Eastern Edison to Narragansett shall be Eastern Edison's General Service Rate 21. The nomenclature has since changed (General Service Rate 21 has become General Service Rate G-1). In order to avoid having to make filings with the FERC whenever the nomenclature changes, Eastern Edison would like, with Narragansett's agreement, to amend the 1982 agreement to refer to the rate for Eastern Edison as "the applicable General Service rate." If this is acceptable, please sign both of the originals of this letter on the line provided below and return one to me so that I can include it with that agreement in the FERC amnesty filing, which we would like to make as soon as possible.

Sincerely,

John D. Carney
President

AGREED TO BY:

R L McCabe

SYSTEM COMPANY

Blackstone Valley Electric Co.

P.O. Box 1111, Washington Highway, Lincoln, Rhode Island 02865 Telephone (401) 333-1400

December 1, 1982

Mr. E.E. Mulligan, President
Massachusetts Electric Company
20 Turnpike Road
Westborough, MA 01581

Dear Mr. Mulligan:

Blackstone Valley Electric Company and Massachusetts Electric Company have been conducting purchases and sales on a "borderline" basis at locations where their franchise territories adjoin. These purchases and sales have been at the rate of $.04 per KWH, a figure established many years ago.

We suggest that in order to bring this rate to current status that all sales and purchases be at the rates specified herein, as they may be in effect from time to time, subject to all applicable adjustments and surcharges (such as FCA, PPCA, and OCA). For Blackstone the rate to be used would be General Service Rate 21, for Massachusetts Electric it would be General Service Rate C-22.

This agreement shall remain in effect until terminated by either party giving the other ninety (90) days written notice.

If the foregoing is agreeable to you, please sign below and return one original to me. This letter will provide the necessary authority for each company to begin billing at the specified rate as of January 1, 1983.

Very truly yours,

William R. Bisson
President

Agreed and Accepted

Dec 6th, 1982
Date

1974 0000

Eastern Utilities
Blackstone Valley Electric Company
Washington Highway
PO Box 1111, Lincoln, RI 02865
(401) 333-1400

December 8, 1993

Mr. John H. Dickson
President
Massachusetts Electric Company
25 Research Drive
Westborough, MA 01582-0005

Dear Mr. Dickson:

In the FERC's amnesty order issued July 30, 1993 it made clear that "borderline" sales such as take place between Blackstone Valley Electric Company ("Blackstone") and Massachusetts Electric Company ("Mass Electric") under the enclosed letter agreement dated December 1, 1982 are jurisdictional (see page 21 of the Appendix to the order). We plan to file the letter agreement before the amnesty window closes on December 31, 1993.

The December 1, 1982 letter agreement provides that the rate to be charged by Blackstone to Mass Electric shall be Blackstone's General Service Rate 21. The nomenclature has since changed (General Service Rate 21 has become General Service Rate G-1). In order to avoid having to make filings with the FERC whenever the nomenclature changes, Blackstone would like, with Mass Electric's agreement, to amend the 1982 agreement to refer to the rate for Blackstone as "the applicable General Service rate." If this is acceptable, please sign both of the originals of this letter on the line provided below and return one to me so that I can include it with that agreement in the FERC amnesty filing, which we would like to make as soon as possible.

Sincerely,

David H. Gulvin

David H. Gulvin
President

AGREED TO BY:

John H. Dickson

1965 0000

Commission Data Request 1-63

Request:

Please provide copies of invoices for all lease-type expenses paid during each of the years 2006, 2007, and 2008. (If the Company only pays a portion of the total lease expense, please provide a summary of each lease invoice showing the total lease expense and the Company's allocated portion of the expense.) Please also indicate when each lease expires.

Response:

Please see Attachments COMM-1-63-A through COMM-1-63-C for the requested information for the years 2006, 2007 and 2008 respectively.

Please see Bulk Attachment COMM-1-63-D (hard copy only) for copies of lease invoices in the years 2006, 2007 and 2008 for direct charges to Narragansett Electric Company. Please see Bulk Attachment COMM-1-63-E (hard copy only) for copies of lease invoices that were partially allocated to Narragansett Electric Company by the Service Company.

The breakdown of information provided in each Summary Listing is as follows:

Attachment COMM-1-63-A (2006)
- Direct Invoices -- All Accounts
- Service Company Invoices (Company 99) -- All Accounts
- Sub-totals by bill pool by month
- Allocator page identifying the applicable allocations for the monthly charges in the bill pool.

Attachment COMM-1-63-B (2007)
- Direct Invoices -- All Accounts
- Service Company Invoices (Company 99) -- All Accounts
- Narragansett Electric (Company 49) Operations and Maintenance summary
- Service Company (Company 99) Operations and Maintenance summary and final bill pool allocations to Narragansett Electric
- Sub-totals by bill pool by month
- Allocator page identifying the applicable allocations for the monthly charges in the bill pool.

Prepared by or under the supervision of: Robert L. O’Brien

Commission Data Request 1-63 (cont.)

Attachment COMM-1-63-C (2008)

- Direct Invoices -- All Accounts
- Service Company Invoices (Company 99) -- All Accounts
- Narragansett Electric (Company 49) Operations and Maintenance summary
- Service Company (Company 99) Operations and Maintenance summary and final bill pool allocations to Narragansett Electric
- Sub-totals by bill pool by month
- Allocator page identifying the applicable allocations for the monthly charges in the bill pool.

Please note that the Company procures a significant level of services from Banker's Leasing Company, which provides vehicles, equipment, software and hardware items. The summary files identify the monthly invoice total and the invoice distribution. The Company has established amortization lives for each asset class. When the asset is fully amortized, an administrative fee applies to any asset that has not been retired.

Attachment COMM-1-63-F are the cover pages and rent schedules for Narragansett's facility lease agreement in Middletown, RI.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 8-7

Request:

Please provide a detailed work flow chart(s) and/or process description(s) of your application for new service process, including (if applicable):

a. Former customer/outstanding balance verification process
b. Procedure for identifying and handling outstanding balances

    i. Balance transfer procedure (if applicable)
    ii. Deferred payment process (if applicable)

c. Positive ID program/process
d. Credit check and/or system to determine credit risk
e. Deposit process, including Surety Bonds, billing, collection and refunding
f. Residential vs. non-residential, if applicable
g. Red- Flag rules

Response:

Please note that the Company has already responded to parts (a) through (g) of this response, except for (d), which is provided below:

(d) There is no external credit check process for residential customers applying for service. For non-residential credit risk policy, please see attachment DIV-8-7(d), provided herewith.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Policy and Procedure Document

Credit and Collections 3.1.63 Commercial (C&I) Customer Credit Policy

SharedServices One company, one way	**Policy and Procedure Document 3.1.63 - C& I Collections Commercial Credit Policy**	

Table of Contents

1.0 Ownership, Change History and Release Control

Ownership

Team	Commercial Credit & Collections (C&I Collections)

Change History

Enter information about changes made to this section of the document.

Ver	Date Modified	Modified By	Brief Description of Changes
0.0	05/12/2009	Jim Koes	Document Created
0.1			Posted to SharePoint

Review History

Ver	Date Reviewed	Reviewed By	Brief Description of Changes
0.0	05/12/2009	Tom LaVeck, in conjunction with Chris Aronson (Legal) and Tracey McCarthy (VP Customer Financial	Issuance of new policy.

		Services)	

Other Reference Documents

Document Name	**Filename**
3.1.49	AI Application for Service Applicant
3.1.50	AI Application for Service Current Customer
3.1.51	AI Application for Service New Applicant
3.1.53	Bankruptcy Notifications
3.1.59	Credit and Collections Commercial (C&I) Deposits

1.1 Document Approval

The undersigned hereby approves and accepts the attached document on behalf of National Grid. Your signature affirms you agree with the purpose and scope of this document, the document has been appropriately reviewed, and you understand and accept responsibility for any assignments or functional implementations based on this document.

Authorization

Approved by/Department	Signature	Date
Approved by/Department	Signature	Date

2.0 Introduction

2.1 Overview and Table of Contents

This **Corporate Credit Risk Policy** formalizes and articulates National Grid's objectives to measure, monitor, and manage credit risk within the Commercial and Industrial Collection organization (C&I Collections). This policy must be effectively deployed and administered by C&I Collections through collaboration and cooperation with the Leadership of various National Grid stakeholder areas including, but not limited to, Sales and Marketing, Energy Solutions Services, Customer Call Center, Accounts Processing (Customer Back Office) and Field Services.

The overall goal is to minimize National Grid's credit exposure by ensuring proper account activation, **Deposit** adequacy, risk-based collection procedures, and regular reviews of customer financial condition and **Market Risk** exposure..

Policy (Section 3) Index

SharedServices One company, one way	Policy and Procedure Document 3.1.63 - C& I Collections Commercial Credit Policy	

3.0 Policy

3.1 Policy Statement

This policy formalizes the National Grid Credit Risk Management Process. The purpose of this policy is to insulate the corporation from financial loss by:

- Defining acceptable levels of risk;
- Establishing a framework to evaluate and identify risks; and
- Establish appropriate means to resolve risks that are deemed unacceptable.

The Credit Risk Management Process provides general principles to guide the National Grid Credit Risk Management Program within Commercial and Industrial Collections. It also sets forth and communicates the methods that will be utilized to avoid, mitigate, or effectively manage credit exposure, while at the same time maintaining regulatory and legal compliance across all states where National Grid **("the company**") provides Service.

This credit risk management policy also applies to all electric accounts of the Long Island Lighting Company d/b/a LIPA **(LIPA)** that are managed by **the Company**.

3.2 Applicability

The Credit Risk Management Process applies to all active National Grid C&I customers and applicants located within National Grid's operating territory in the US ("**US Service Area**"), as well as all active LIPA C&I customers and applicants located within LIPA's operating territory on Long Island ("**LIPA Service Area**").

3.3 Definitions

3.3.1 **Account Initiation –** The process of setting up electric and gas service for a **New Customer,** or a new location for an **Existing Customer. [** Policies 3.1.49 – AI Application for Service Applicant; 3.1.50 – Application for service Current Customer; 3.1.51 – AI Application for Service New Applicant – see Section 1 above for reference links]

3.3.2 **Alternate Energy Supplier, a/k/a Energy Supply Company (ESCo) –** See Section 3.11

3.3.3 **Credit Risk** is the risk to earnings or capital associated with a third party's (obligor's) failure to meet the terms of any contract or otherwise perform as agreed.

3.3.4 **Corporate Credit Risk Management Policy** is also referred to as "**Policy"**.

3.3.5 **Credit Review Committee (CRC)** – Also known as a Governance Committee – See Section 3.13

3.3.6 **Credit Risk Management Team** is comprised of employees within the Commercial and Industrial Collections Department (C&I Collections) who are dedicated to the implementation of this Policy.

3.3.7 **Current exposure** is the amount of any outstanding receivables that would be uncollected in the event of customer default.

3.3.8 **Customer Account** is a specific account number assigned to an electric or gas meter at a specific customer location. Also known as an **"Individual Account".**

3.3.9 **Customer Level** is all accounts of a particular customer, including any accounts of customer's affiliated companies

3.3.10 **Default risk** is the customer **Credit Risk** relating to defaults and delayed payment of invoices.

3.3.11 **Deposit** is security held to mitigate losses, if incurred. Standard forms of **Deposit** include cash, surety bond and letters of credit. [Reference: Policy 3.1.59 - Credit & Collections Commercial (C&I) Deposit – see section 1 above for reference link]

3.3.12 **Dun & Bradstreet (D&B) - A third Party Credit Rating Agency**

3.3.13 **Existing Customer** is a customer that has one or more existing accounts with National Grid or one or more existing accounts with **LIPA**, and is not deemed a **New Customer**, as defined in this document.

SharedServices One company, one way	**Policy and Procedure Document 3.1.63 - C& I Collections Commercial Credit Policy**	

3.3.14 Experian - A third Party Credit Rating Agency

3.3.15 External Customer Information is information that is created by any person or entity, such as **Dun & Bradstreet** or **Experian**, that is neither employed by or affiliated with one of the National Grid companies

3.3.16 Fitch - A third Party Credit Rating Agency

3.3.17 Individual Account - See Customer Account, Section 3.3.8

3.3.18 Large Use Customer is a customer whose electric and gas charges (delivery and commodity costs if applicable) at all locations is $500,000 or greater on an annual basis. This classification is established either by qualifying usage of prior customer at the applicant's premise or by a Service Application indicating a qualifying usage estimate of the new Service. A Large Use Customer would include all customers who have multiple locations that use less than $500,000 per year in gas or electric Service at each location, but when aggregated exceed the $500,000 threshold

3.3.19 Market Risk – See Section 3.6.2.

3.3.20 Moody's - **A third Party Credit Rating Agency**

3.3.21 New Customer is a customer who was not the last previous customer served at the affected premises, regardless of whether that entity currently has or previously had **Service** elsewhere.

3.3.22 Negotiated Payment Agreement – A contractual collection agreement between National Grid and one of its customers, or **LIPA** and one of its customers, which is designed to collect unpaid utility bills from the customer.

3.3.23 Potential exposure is the risk associated with possible future increases in the value of an open contract that would be lost if a customer fails to honor its commitments.

3.3.24 Service is the supply and delivery of natural gas and/or electricity to National Grid Customers, and the supply and delivery of electricity to **LIPA** Customers

3.3.25 Service Application is a non-residential gas and electric Service application completed by a New Customer and provided to National Grid and **or LIPA**.

3.3.26 Standard & Poors - A third Party Credit Rating Agency

3.3.27 Third Party Credit Rating Agency – An independent company including, but not limited to, Experian, Dun & Bradstreet, Moods, Fitch and Standard & Poors, who is in the business of providing personal and/or business credit reports, credit ratings, and other credit rating services.

3.3.28 Third Party Credit Rating Criteria – is credit rating criteria that is statistically established provided by an independent company who is in the business of providing personal and/or business credit rating services.

3.3.29 Third Party Credit Reports – are credit reports that are provided by an independent company who is in the business of providing personal and/or business credit reports and credit rating services.

3.4 Roles and Responsibilities

3.4.1 The **Corporate Credit Risk Policy** formalizes National Grid's and **LIPA's** strategy, policy and procedures for all credit related activities by articulating objectives to measure, monitor, and mitigate **Credit Risk** across the **US service area** and the **LIPA service area**.

3.4.1.1 C&I Collections are responsible for developing the strategy, policy and procedures for all related activities in regards to C&I customer credit. C&I Collections are accountable to key stakeholders across Lines of Business (LOB's) and the Energy Services Solutions (ESS) Executive team.

3.4.1.2 National Grid Key stakeholders including, but not limited to, Energy Solutions Services, Customer Call Center, Accounts Processing (Customer Back Office) and Field Services provide resources to support the implementation of the Credit Risk Management Process.

3.4.1.3 C&I Collections will consult with Regulatory, ESS, Media Relations, Legal, Government Affairs and the Long Island Power Authority **(LIPA**) if customer issues arise.

3.4.2 C&I Collections will communicate this **Policy** to key stakeholders supporting the process. In order to ensure comprehension and adherence of this **Policy**, C&I Collections will provide all necessary training. Metrics are established to ensure there is adherence, and will be communicated to all key stakeholders on a monthly basis.

3.4.3 A Governance Committee will mediate requested deviations from this **Policy** as outlined in section 3.13**.**

3.5 Guiding Principles

3.5.1 The following guiding principles provide the foundation for credit risk assessment and mitigation:

3.5.1.1 Customer validation by C&I Call Center Rep. at **Account Initiation** enables accurate credit analysis later in the customer lifecycle

3.5.1.2 Assessment and collection of **Deposits** as a condition of **Service** is the most efficient means to secure risk when the applicant is deemed risky prior to receiving **Service**. [Policy 3.1.59 – Commercial (C&I) Deposits – see section 1 above for reference link]

3.5.1.3 C&I Collections will analyze measure and manage **Credit Risk** utilizing all internal customer information and external market information. C&I Collections will perform this analysis in a fair and non-discriminatory manner, and will report the results for each customer on a monthly basis.

3.5.1.4 C&I Collections will set securitization levels for each customer, based on internal and **External Customer Information** and within applicable regulatory guidelines.

3.5.1.5 This **Policy** is meant to serve as a general guideline. However, C&I Collections explicitly recognize that the marketplace moves very quickly and laws; regulations and **Third Party Credit Rating Criteria** can change with little warning. As such, C&I Collections will endeavor to continuously adjust this Policy to reflect these changing conditions.

3.6 Portfolio Risk Review

3.6.1 **Credit Risk** arises from a customer's financial instability, which can come from many sources. C&I Collections will review **Credit Risk** exposure from various perspectives, which could include Customer Level Risk, Industry Level Risk and Individual Account Level Risk (high volume users). Both internal and external data will be used to determine financial risk.

3.6.2 **Market Risk** represents the potential adverse impact of changes in the market value of a particular commitment. **Credit and Market Risks** are interrelated as market movements will impact the value of credit risk positions (amount owed by customers) over time.

3.6.3 The **Credit Risk Management Team** within C&I Collections will perform risk reviews on the commercial and industrial portfolio (C&I Portfolio) and report monthly to the Credit Review Committee, **LIPA** and key stakeholders across lines of business. The risk review will include the following:

3.6.3.1 C&I Collections will engage an external vendor (e.g. - **Experian**, **Dun & Bradstreet**) to receive regular periodic market reports regarding current economics on all industries as well as customer alerts regarding companies who have become financially unstable and have the potential for bankruptcy or restructuring. The **Credit Risk Management Team** will review and seek the appropriate security **Deposi**t where necessary, and in accordance with applicable laws and regulations.

3.6.3.2 **Third Party Credit Reports** and/or audited company financials will be reviewed by the Credit Risk Analysts where either high risk is identified or where support is needed by the Collections Analyst.

3.6.3.3 C&I Collections will review **Deposit** securitization levels for high risk accounts to identify insufficient or inconsistent securitization levels, and will recommend a strategy to properly securitize these accounts.

3.6.3.4 C&I Collections will audit the C&I Portfolio to ensure compliance with established policies by the Customer Contact Centers and Energy Services Solutions regarding the administration of this process.

3.6.4 Aggregated Credit Risk

3.6.4.1 In determining risk, customer exposure will be aggregated by C&I Collections at a **Customer Level** across all National Grid operating territories whenever possible. Customer risk for **LIPA** will be aggregated separately. In collaboration with the Energy Solutions Services organization, data hygiene will be an ongoing project with top priority for all customer information systems in order to properly identify **the company's** and **LIPA's** customer relationships, history, and full debt exposure.

3.6.5 Evaluating and Addressing Customer Risk

3.6.5.1 Acceptable levels of risk for Customer Accounts

3.6.5.1.1 Where a customer applying for **Service** has a twenty-four (24) month payment history, or longer where specified by state tariff, on one or more existing accounts with the same company they are applying to for Service with no late payments on any of them, provided the customer applying for **Service** can positively identify themselves as the same customer, or

3.6.5.1.2 The customer maintains a minimum rating from one of the following **Third Party Credit Rating Agencies:**

Minimum	**Fitch Ratings**	**Moody's Investor Service**	**Standard & Poor's**	**Dun & Bradstreet**
Rating - >	BBB	Baa2	BBB	1A2

Note: credit rating definitions can be found on Exhibit A.

3.6.5.1.3 For **Large Use Customers**, the **Credit Review Committee** has deemed the risk acceptable through the escalation process outlined in section 3.13.2

3.6.5.1.4 For purposes of this document, a payment will not be considered late if the late payment was the result of delayed invoicing by **the Company** to the customer, or is the result of a valid dispute due to National Grid operational issues.

3.7 C&I Customer Deposits & Refunds

3.7.1 **Deposit** adequacy is most critical in order to minimize losses from National Grid and **LIPA**'s commercial and Industrial customer portfolios. All deposits will be obtained and refunded in accordance with Policy 3.1.59 – Commercial (C&I) Deposits – see Section 1 above for reference link.

3.7.2 The process of minimizing credit exposure for all C&I Customers involves regularly scheduled **Deposit** adequacy reviews which will be performed by the C&I Collections.

3.7.3 **The Company** will accept cash, surety bond, or an irrevocable bank letter of credit (LOC) as the "**Standard forms of Deposit**". In the case of New Hampshire, a direct debit account for payment may also be pledged.

3.7.3.1 The request for a Non Standard forms of **Deposit** "**Alternative forms of Deposit"** shall be reviewed by the **Credit Risk Management Team** within C&I Collections for acceptance or denial in accordance with **Company** policy and if applicable, State regulation.

3.7.3.1.1 In addition, the enforceability of any **Alternative form of Deposit** must be verifiable and, if it is provided by another customer of either National Grid or **LIPA**, that customer must be in good standing with the **Company** and/or **LIPA**.

3.7.3.1.2 The terms and conditions of the letter of credit, surety bond or any **Alternative form of Deposit** will be provided by National Grid.

3.7.4 High Risk Accounts

3.7.4.1 C&I Collections will work with assigned National Grid Account Managers to ensure that appropriate actions are being taken to securitize these accounts and minimize loss to the company.

3.7.4.1.1 The C&I Collections representative will manually prepare a **Deposit** assessment letter, and it will either be sent directly to the customer or to the Account Manager for delivery to the Customer, describing the reason for the assessment and requesting payment in compliance with state regulations.

3.7.4.1.2 Any customer questions, issues or concerns will be managed by C&I Collections.

3.7.4.1.3 C&I Collections will follow-up for any unpaid deposits, and will process any paid deposits.

3.7.4.1.4 Any **Negotiated Payment Agreement** will be done in accordance with section 3.12.

3.7.3.1.3 For those accounts unwilling to provide the requested security, guidance from the **Credit Review Committee** will be sought.

3.7.4.2 For those high risk accounts that have <u>not</u> been assigned an Account Manager, C&I Collections will pursue the appropriate security **Deposits**.

3.7.4.2.1 Any commercial customer who has an account which has been in arrears more than twice in a full twelve (12) month period immediately proceeding the date the Account is evaluated and where a **Deposit** is not on hand, C&I Collections will assess a **Deposit** in accordance with state regulations.

3.7.4.2.2 C&I Collections will manage any customer questions or concerns associated with the **deposit** billing.

3.7.4.2.3 The **Credit Risk Management Team** will perform an audit of **Deposits** on a monthly basis. If it is determined that an assessed

Deposit has not been paid in the time allotted by the regulations and National Grid, C&I Collections will request that a C&I Collections Analyst make an outbound telephone call within seventy-two (72) hours.

3.7.4.2.4 If a mutually acceptable payment agreement has not been established in accordance with Section 3.12 and/or a **Deposit** in full has not yet been collected, a demand letter will be sent to the customer advising them that failure to comply with the **Deposit** request may result in the possible termination of their **Service,** as allowed by and in accordance with applicable state termination regulations.

3.7.5 High Risk Accounts with Arrears

3.7.5.1 In accordance with section 3.7.4.1, C&I Collections will work with assigned National Grid Account Managers to ensure that appropriate actions are being taken to securitize these accounts and minimize any outstanding arrears.

3.7.5.2 For those high risk accounts with arrears that have not been assigned an Account Manager, C&I Collections will pursue the appropriate security **Deposits** along with any outstanding account payments in accordance with section 3.7.4.2.

3.7.5.3 **Deposits** will not be waived on high risk accounts that clear up their arrears.

3.7.6 **Deposit** Refund Requirements

3.7.6.1 **Deposit** refunds will be managed in accordance with Policy 3.1.59 – Commercial (C&I) Deposits - see Section 1 above for reference link.

3.7.6.2 A **Deposit** will be held in accordance with applicable State regulation – “the State **Deposit** Period”. Typically, a **Deposit** refund will be considered at the end of the applicable State **Deposit** Period.

3.7.7 **Deposit** Reviews (Monitoring of Customer Usage Patterns)

3.7.7.1 Existing **Deposits** will be reviewed periodically against existing and expected usage patterns. Any applicable adjustments will be made in accordance with applicable state regulation. This will include energy delivery charges and if applicable, energy supply charges.

3.7.8 Installment Payments

3.7.8.1 Installment payments will be allowed as authorized by applicable State Regulation.

3.7.9 Acceptable **Deposit** Waiver Criteria

3.7.9.1 A decision by an officer of one of the National Grid Companies for National Grid accounts

3.7.9.2 A decision by an authorized representative of LIPA for LIPA accounts.

3.7.9.3 State regulation(s)

3.7.9.4 All Federal and State Governmental entities – including local towns and municipalities
3.7.9.5 A decision by the C&I Collections Manager and/or Director
3.7.9.6 A order issued by the Public Service Commission, a bankruptcy court, or any other court of competent jurisdiction.

<u>Any decision to waive a **Deposit** must be documented on the account.</u>

3.8 Accounts w/ Arrears

3.8.1 Monitoring of **Existing Customer** Payment Performance

3.8.1.1 Due to the changing financial profile of each **Existing Customer**, payment performance will be monitored to identify the need for a **Deposit** - based on the following criteria:

- The **Existing Custo*mer*** has arrears greater than sixty (60) days on one or more of their accounts; or
- The **Existing Customer** has defaulted on their payment agreement.

If any of the above conditions exist, a security **Deposit** will be required in the amount allowed by State regulation.

3.8.2 Managed and National Accounts:

3.8.2.1 **The Credit Risk Management Team** will review all **Large Use Customer** accounts that are in arrears on a monthly basis and will generate a report outlining the findings.

3.8.2.2 Any **Large Use Customer** who has an account which has been in arrears more than twice in a full twelve (12) month period immediately proceeding the date the Account is evaluated and where a **Deposit** is not on hand, C&I Collections will work with the Account Manager to clear up such arrears

3.8.3 All other accounts excluding Managed and National Accounts.

3.8.3.1 Any commercial customer who has an account which has been in arrears more than twice in a full twelve (12) month period immediately proceeding the date the Account is evaluated and where a **Deposit** is not on hand, C&I Collections will contact the customer to clear up such arrears.

3.8.3.2 If a mutually acceptable payment agreement has not been established and/or a **Deposit** in full has not yet been collected, a demand letter will be sent to the customer advising them that failure to comply with the deposit request may result in the possible termination of their **Service,** as allowed by and in accordance with applicable state termination regulations.

3.9 Customer Accounts in Arrears & Terminated for Non-Payment

3.9.1 In all cases where **Service** has been terminated for non-payment, C&I Collections will assess a **Deposit** on all customer accounts, and **Service** will not be restored without payment in full of the arrears on all customer accounts and any required **Deposits**.

3.9.1.1 In accordance with section 3.12, a **Negotiated Payment Agreement** will be considered where appropriate

3.10 Accounts in Bankruptcy

3.10.1 In all cases where a bankruptcy filing has been received by the Company, a **Deposit** may be required on all affected Customer accounts in accordance with applicable National Grid or **LIPA** policy [Reference: Policy 3.1.53 - Credit & Collections Bankruptcy Notifications – see Section 1 above for reference link]

3.10.2 **Deposits** may be required for accounts in bankruptcy as a result of agreement, settlement or by a bankruptcy court order.

3.11 Customers Served by an Alternate Energy Supplier - a/k/a Energy Supply Company (ESCo)

3.11.1 In an effort to promote the development of retail energy markets, Customers are encouraged to utilize ESCo's for their energy supply needs. Whether or not a Customer utilizes an ESCo, the delivery of their commodity remains with National Grid and/or **LIPA**.

3.11.1.1 **Delivery Charges only:** If applicable, **Deposits** will be assessed, for both **New and Existing Customers,** in accordance with this **Credit Risk Policy**.

3.11.1.2 **Supply and Delivery**: In the event that National Grid and/or **LIPA** provide both the supply and delivery of a customers energy needs, any applicable **Deposits** will be assessed in accordance with this **Credit Risk Policy.** This includes any energy supply where the Customer utilizes an ESCo, but the ESCo's billing and receivable obligations have been assumed by National Grid and/or **LIPA**.

3.11.1.3 **Customers no longer being served by an ESCo**: If a Customer is no longer obtaining their energy supply from an ESCo and National Grid and/or **LIPA** have assumed the supply obligations, any applicable **Deposit** will be assesses in accordance with this **Credit Risk Policy.**

3.12 Negotiated Payment Agreements

3.12.1 **Negotiated Payment Agreements (NPA)** will be allowed if approved by C&I Collections only.

3.12.2 C&I Collections will provide the document that is to be used to document the customer's agreement to the **NPA**. This document shall include all

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agreed upon commitments with the customer, and shall be issued in accordance with applicable state regulatory requirements.

3.12.3 The **NPA** is primarily used to collect accounts with arrears.

3.12.4 The **NPA** allows a customer to pay the overdue amounts in installments, along with their current bills in full, over a short period of time.

3.12.5 National Grid and **LIPA** are allowed to charge interest on any unpaid customer bills. A **NPA** does not automatically eliminate this option.

3.12.6 Customer eligibility for a **NPA** will be determined in accordance with applicable state regulation.

3.13 Credit Review Committee (CRC)

3.13.1 Credit Committee Responsibilities

3.13.1.1 The **Credit Risk Management Team** within C&I Collections has the responsibility to report issues in advance to the **Credit Review Committee** (**CRC)** and utilize Regulatory, Legal, Government Affairs and Finance as advisors. The **CRC**'s role is to review and ensure that defined account securitization levels are achieved through cooperation and adherence by all National Grid Business Units.

3.13.1.2 This **Credit Review Committee** is comprised of the VP Customer Financial Services, VP Sales and Marketing, or designee, VP Finance or designee, VP Electric or designee, VP Finance Gas or designee, the VP Energy Solutions Services or designee, and the **LIPA** VP Retail Services of or designee, who would mediate and have final authority regarding any Business Unit request to deviate from the standard securitization policy.

3.13.1.2.1 The **LIPA** VP of Retail Services or designee would mediate and have final authority regarding any Business Unit request to deviate from the standard securitization policy for any **LIPA** specific accounts,

3.13.1.3 The Director of Credit and Collections serves as the chair of the group and has the responsibility to call meetings to be scheduled within five (5) business days when necessary and to make sure all documentation is gathered and decisions are recorded and implemented.

3.13.1.4 A consensus vote would be required for decision/ approval.

3.13.1.5 The **Credit Risk Management Team** has the responsibility to act upon any determined enhancements or deficiencies to the policy or procedures.

3.13.1.6 The **Credit Review Committee** (**CRC)** will meet as necessary with representative(s) from the Credit Management Team to review credit related matters. Such discussions can include, but are not limited to,

- **Deposit** Securitization Levels vs. Total Accounts Receivable – Review unsecured percentage
- Status of new **Large Use Customers**
- Issues regarding **Large Use Customers** or industry segments
- Monitoring measurements of National Grid and **LIPA's** customers at a Customer Level, including concentration of credit risks with the aggregate roll up of all accounts falling under the parent level.
- Status of all major exceptions to established credit requirements outlined in this **Credit Risk Policy.**
- Review and approve proposed customer credit risk modification strategies including actions taken to address customers with problem risk ratings
- Evaluating the results and conclusions of various credit research activities.

3.13.2 **CRC** Procedure for Appeals Regarding Security Request

3.13.2.1 The **Credit Risk Management Team** within C&I Collections will assemble appropriate documentation regarding arrears or credit analysis findings, and email this documentation to the **Credit Review Committee** for its review and acceptance.

3.14 Documentation, Compliance & Reporting

3.14.1 Documentation

3.14.1.1 The **Credit Risk Management Team** within C&I Collections must ensure that proper documents are maintained for each customer.

3.14.1.2 Letters of Credit, Surety Bonds, Personal Guarantees, Credit Reports and other Legal documentation for C&I Customers must be inventoried and maintained in a secure place for each customer by the Accounts Processing Department and/or C&I Collections, as appropriate.

3.14.1.3 Inventory lists must be kept regarding **Deposits** in order to ensure that they are renewed, if necessary, prior to expiration.

3.14.2 Compliance

3.14.2.1 Annual audits will be performed by an independent party to be named by the Commercial and Industrial Collections Department Manager to verify such compliance.

3.14.2.2 The **Credit Risk Management Team** will provide guidance and support to the Accounts Processing Department on an on-going and as needed basis.

3,14.3 Management Reporting

3.14.3.1 All key stakeholders, including the **Credit Review Committee** members, shall receive Quarterly reports regarding the corporation's **Credit Risks**.

3.14.3.1.1 The **Credit Risk Management Team** would provide a report on any current economic situation that presents industry risk to National Grid and/or **LIPA**, or involves specific customer alerts

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Schedule of Exhibits

- Exhibit A - Credit Rating Definitions

Exhibit A– Credit Rating Definitions

D&B Rating
The US 5A to HH ratings reflect company size based on net worth or equity as computed by D&B. These ratings are assigned to businesses that have supplied D&B with current financial information.

The 1R and 2R ratings categories reflect company size based on the total number of employees for the business. They are assigned to business files that do not contain a current financial statement. For 5A to HH Ratings, the Composite Credit Appraisal is a number between 1 and 4 that makes up the second half of the company's Rating and reflects an overall assessment of creditworthiness. Our creditworthiness assessment is based on both payments and financial stability. In 1R and 2R Ratings, the 2, 3, or 4 creditworthiness indicator is based on analysis by D&B of public filings, trade payments, business age and other important factors. 2 is the highest Composite Credit Appraisal a company not supplying D&B with current financial information can receive.

Financial Strength		Composite Credit Appraisal			
Rating	US $	High	Good	Fair	Limited
5A	50,000,000 and over	1	2	3	4
4A	10,000,000 to 49,999,999	1	2	3	4
3A	1,000,000 to 9,999,999	1	2	3	4
2A	750,000 to 999,999	1	2	3	4
1A	500,000 to 749,999	1	2	3	4
BA	300,000 to 499,999	1	2	3	4
BB	200,000 to 299,999	1	2	3	4
CB	125,000 to 199,999	1	2	3	4
CC	75,000 to 124,999	1	2	3	4
DC	50,000 to 74,999	1	2	3	4
DD	35,000 to 49,999	1	2	3	4
EE	20,000 to 34,999	1	2	3	4
FF	10,000 to 19,999	1	2	3	4
GG	5,000 to 9,999	1	2	3	4
HH	Up to 4,999	1	2	3	4

Rating Classification		Composite Credit Appraisal			
Rating	Number of Employees	High	Good	Fair	Limited
1R	10 employees and over		2	3	4
2R	1 to 9		2	3	4

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Alternative Ratings Used	
INV	Indicates that D&B is currently conducting an investigation to gather information for a new report.
DS	Indicates that the information available does not permit D&B to classify the company within our rating key.
-- (blank)	The blank symbol should not be interpreted as indicating that credit should be denied. It simply means that the information available to D&B does not permit us to classify the company within our rating key and that further enquiry should be made before reaching a decision. Some reasons for using a "-" symbol include: deficit net worth, bankruptcy proceedings, lack of insufficient payment information, or incomplete history information.
ER	Certain lines of business, primarily banks, insurance companies and government entities do not lend themselves to classification under the D&B Rating system. Instead, we assign these types of businesses an Employee range symbol based on the number of people employed. No other significance should be attached to this symbol. ERN should not be interpreted negatively. It simply means we do not have information indicating how many people are employed at this firm.
NQ	Not Quoted. This is generally assigned when a business has been confirmed as no longer active at the location, or when D & B is unable to confirm active operations. It may also appear on some branch reports, when the branch is located in the same city as the headquarters.

US Employee Range Designation	
ER1	1000 or more employees
ER2	500 to 999 employees
ER3	100 to 499 employees
ER4	50 to 99 employees
ER5	20 to 49 employees
ER6	10 to 19 employees
ER7	5 to 9 employees
ER8	1 to 4 employees
ERN	Not Available

Fitch Ratings These may be modified by a "+" or a "-". A modifier does not always exist.

Rating	Definition
AAA	Highest credit quality. 'AAA' ratings denote the lowest expectation of credit risk. They are assigned only in case of exceptionally strong capacity for payment of financial commitments. This capacity is highly unlikely to be adversely affected by foreseeable events.
AA	Very high credit quality. 'AA' ratings denote expectations of very low credit risk. They indicate very strong capacity for payment of financial commitments. This capacity is not significantly vulnerable to foreseeable events.
A	High credit quality. 'A' ratings denote expectations of low credit risk. The capacity for payment of financial commitments is considered strong. This capacity may, nevertheless, be more vulnerable to changes in circumstances or in economic conditions than is the case for higher ratings.
BBB	Good credit quality. 'BBB' ratings indicate that there are currently expectations of low credit risk. The capacity for payment of financial commitments is considered adequate but adverse changes in circumstances and economic conditions are more likely to impair this capacity. This is the lowest investment grade category.
BB	Speculative. 'BB' ratings indicate that there is a possibility of credit risk developing, particularly as the result of adverse economic change over time; however, business or financial alternatives may be available to allow financial commitments to be met. Securities rated in this category are not investment grade.
B	Highly speculative. **For issuers and performing obligations**, 'B' ratings indicate that significant credit risk is present, but a limited margin of safety remains. Financial commitments are currently being met; however, capacity for continued payment is contingent upon a sustained, favorable business and economic environment. **For individual obligations**, may indicate distressed or defaulted obligations with potential for extremely high recoveries. Such obligations would possess a Recovery Rating of 'RR1' (outstanding).
CCC	**For issuers and performing obligations,** default is a real possibility. Capacity for meeting financial commitments is solely reliant upon sustained, favorable business or economic conditions. **For individual obligations**, may indicate distressed or defaulted obligations with potential for average to superior levels of recovery. Differences in credit quality may be denoted by plus/minus distinctions. Such obligations typically would possess a Recovery Rating of 'RR2' (superior), or 'RR3' (good) or 'RR4' (average).
CC	**For issuers and performing obligations**, default of some kind appears probable. **For individual obligations**, may indicate distressed or defaulted obligations with a Recovery Rating of 'RR4' (average) or 'RR5' (below average).

C	**For issuers and performing obligations**, default is imminent. **For individual obligations**, may indicate distressed or defaulted obligations with potential for below-average to poor recoveries. Such obligations would possess a Recovery Rating of 'RR6' (poor).
RD	Indicates an entity that has failed to make due payments (within the applicable grace period) on some but not all material financial obligations, but continues to honor other classes of obligations.
D	Indicates an entity or sovereign that has defaulted on all of its financial obligations. Default generally is defined as one of the following: Failure of an obligor to make timely payment of principal and/or interest under the contractual terms of any financial obligation; The bankruptcy filings, administration, receivership, liquidation or other winding-up or cessation of business of an obligor; The distressed or other coercive exchange of an obligation, where creditors were offered securities with diminished structural or economic terms compared with the existing obligation.

Moody's Rating Classification

Rating	Definition
Aaa	Obligations rated Aaa are judged to be of the highest quality, with minimal credit risk.
Aa	Obligations rated Aa are judged to be of high quality and are subject to very low credit risk.
A	Obligations rated A are considered upper-medium grade and are subject to low credit risk.
Baa	Obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics.

Moody's Modifiers

High	Mid	Low
1	2	3
1	2	3
1	2	3
1	2	3

Ba	Obligations rated Ba are judged to have speculative elements and are subject to substantial credit risk.	1	2	3
B	Obligations rated B are considered speculative and are subject to high credit risk.	1	2	3
Caa	Obligations rated Caa are judged to be of poor standing and are subject to very high credit risk.	1	2	3
Ca	Obligations rated Ca are highly speculative and are likely in, or very near, default, with some prospect of recovery of principal and interest.	1	2	3
C	Obligations rated C are the lowest rated class of bonds and are typically in default, with little prospect for recovery of principal or interest.	1	2	3

S&P Ratings

These may be modified by a "+" or a "-". A modifier does not always exist.

Rating	Definition
AAA	An obligation rated 'AAA' has the highest rating assigned by S & P. The obligor's capacity to meet its financial commitment on the obligation is extremely strong.
AA	An obligation rated 'AA' differs from the highest-rated obligations only to a small degree. The obligor's capacity to meet its financial commitment on the obligation is very strong.
A	An obligation rated 'A' is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong.

BBB	An obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation.
BB	An obligation rated 'BB' is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.
B	An obligation rated 'B' is more vulnerable to nonpayment than obligations rated 'BB', but the obligor currently has the capacity to meet its financial commitment on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation.
CCC	An obligation rated 'CCC' is currently vulnerable to nonpayment, and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation. In the event of adverse business, financial, or economic conditions, the obligor is not likely to have the capacity to meet its financial commitment on the obligation.
CC	An obligation rated 'CC' is currently highly vulnerable to nonpayment.
C	A 'C' rating is assigned to obligations that are currently highly vulnerable to nonpayment, obligations that have payment arrearages allowed by the terms of the documents, or obligations of an issuer that is the subject of a bankruptcy petition or similar action which have not experienced a payment default. Among others, the 'C' rating may be assigned to subordinated debt, preferred stock or other obligations on which cash payments have been suspended in accordance with the instrument's terms.
D	An obligation rated 'D' is in payment default. The 'D' rating category is used when payments on an obligation are not made on the date due even if the applicable grace period has not expired, unless S & P believes that such payments will be made during such grace period. The 'D' rating also will be used upon the filing of a bankruptcy petition or the taking of a similar action if payments on an obligation are jeopardized.
NR	This indicates that no rating has been requested, that there is insufficient information on which to base a rating, or that S & P does not rate a particular obligation as a matter of policy.

Obligations rated 'BB', 'B', 'CCC', 'CC', and 'C' are regarded as having significant speculative characteristics. 'BB' indicates the least degree of speculation and 'C' the highest. While such obligations will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions.

3.3 Associated Processes

4.0 Detailed Processes and Procedures

4.1 Process Flow Diagram –

4.2 References & Links

Division Data Request 10-5

Request:

`Please provide workpapers showing how the rate year billing determinants on Schedule NSG-HSG-6, Pages 10-12 were developed from actual test year billing determinants. The response should show how test year billing determinants were adjusted for customer growth, normal weather, and any other factors, to derive the rate year billing determinants and should be provided in its Excel version.

Response:

The rate-year billing determinants were derived from the forecast of gigawatthour (gWh) sales and customer counts described in the testimony of Alfred P. Morrissey. As the testimony explains, monthly gWh sales and customer counts for the Company's main revenue classes were forecast from econometric models relating these sales and customer counts to economic variables, weather and other factors affecting the demand for electricity. The forecast assumed normal weather. Rate year economic conditions were obtained from Moody's Economy.com. The econometric forecast of gWh sales was adjusted for the impact of additional demand-side management (DSM) programs the Company has proposed for 2010, beyond what it achieved in 2008. The resulting rate year forecast of gWh sales and customer counts, by revenue class, were allocated to rate classes using linear regression equations that predicted each rate class's share of revenue class growth, based on historical trends.

The econometric models described in Morrissey's testimony were estimated using PC-SAS statistical software and are attached as "DIV 10-5 Attachment 1.pdf." The data sets used to estimate these models are provided in the attached Excel workbook, "DIV 10-5 Attachment 2.xls." This workbook is laid out as follows:

DIV-10-5 Attachment 2.xls

Tab	Description
KWh	KWh input data to the econometric models
Customers	Customer input data to the econometric models
Exogenous	Exogenous input data to the econometric models
Key	Key for use in reviewing the spreadsheets

Prepared by or under the supervision of: Alfred P. Morrissey, Jr

Division Data Request 10-5 (cont.)

Note that the econometric models for customers with electric heating were used only to allocate the forecast of total residential kWh sales into space heating revenue classes. Note also that model residuals from the 2008 test year were added to the forecast results so that model-produced gWh and customer growth rates could be applied directly to the 2008 test year billing determinants.

The DSM adjustment to the gWh forecast, as well as the allocation of the revenue class forecast to rate classes, was performed in the attached Excel workbook, "DIV 10-5 Attachment 3.xls." This workbook setup as follows:

DIV 10-5 Attachment 3.xls

Tab	Description
Model_Produced_Results	Monthly history and econometric forecast of kilowatthour (kWh) by revenue class. These kWh are shown on Schedule NG-APM-1 of Morrissey's testimony as annual gWh (Schedule NG-APM-2 shows the same forecast but with gWh history weather-normalized).
Incremental_DSM	Incremental DSM kWh subtracted from the econometric forecast in the Model_Produced_Results tab.
RevClassKWhFC	Monthly history and kWh forecast by revenue class with 2010 adjusted for incremental DSM.
RateClassAllocation	Rate class kWh regressed against a linear time trend and used to allocate the revenue class kWh forecast to rate classes
MonthlyKWhReport	Shows monthly historical and forecast kWh, by revenue class and rate class, adjusted for incremental DSM, along with growth rates and annual totals.
AnnualKWhReport	Shows the historical and forecast kWh, by revenue class and rate class, aggregated to calendar years, including the 2008 test year and the 2010 rate year. The 2010 kWh in this report are shown on NG-APM-6 and are consistent with the billing determinants shown on NG-HSG-6 with the exception of the streetlight billing determinants which were forecast based on the December 2008 streetlights inventory, as identified in the response to Division Data Request 3-12.

Prepared by or under the supervision of: Alfred P. Morrissey, Jr

Division Data Request 10-5 (cont.)

ForecastResults	Shows monthly historical and forecast kWh aggregated to revenue and rate class. Forecasted 2010 kWh are consistent with the rate year billing determinants shown in NG-HSG-6 with the exception of the streetlight billing determinants which were forecast based on the December 2008 streetlights inventory, as identified in the response to Division Data Request 3-12.
Key	Key for use in reviewing the spreadsheets

The allocation of the revenue class forecast of customer counts to rate classes, was performed in the attached Excel workbook, "DIV 10-5 Attachment 4.xls." This workbook setup as follows:

DIV 10-5 Attachment 4.xls

Tab	Description
RevClassKWhFC	Monthly customer count history and forecast by revenue class.
RateClassAllocation	Rate class customer counts regressed against a linear time trend and used to allocate the revenue class customer forecast to rate classes
MonthlyCustomerReport	Shows monthly customer historical and forecast, by revenue class and rate class, along with growth rates and annual totals.
AnnualCustomerReport	Shows the historical and forecast customers, by revenue class and rate class, aggregated to calendar years, including the 2008 test year and the 2010 rate year. The 2010 customers in this report are shown on NG-APM-5 and are consistent with the billing determinants shown on NG-HSG-6.
ForecastResults	Shows monthly historical and forecast customers aggregated to revenue and rate class. Forecasted 2010 customers are consistent with the rate year billing determinants shown in NG-HSG-6.
Key	Key for use in reviewing the spreadsheets

Prepared by or under the supervision of: Alfred P. Morrissey, Jr

Division Data Request 10-10

Request:

Please provide the Company labor expense and outside contractor expense charged to each distribution operation and maintenance account (FERC Accounts 580 – 598) in 2008.

Response:

Please see the Attachment DIV 10-10.

Prepared by or under the supervision of: Robert L. O'Brien

The Narragansett Electric Company
d/b/a National Grid
Labor and Outside Contractor Expense Charged to Distribution O&M Expense (FERCs 580 - 598)
Calendar 2008

Line	**Labor**			**Outside Contractors**		
1	Expense Type Descr	(Multiple Items)		Expense Type Descr	(Multiple Items)	
2	Orig Business Unit	(Multiple Items)		Orig Business Unit	(Multiple Items)	
3						
4	Sum of Posted Jrnl $		Calendar Year	Sum of Posted Jrnl $		Calendar Year
5	Bus Unit Descr	Regulatory Acct	2008	Bus Unit Descr	Regulatory Acct	2008
6	Narragansett Electric Company	580000	598,755	Narragansett Electric Company	580000	(189,508)
7		581000	60,832		581000	5,473
8		582000	858,061		582000	286,221
9		583000	1,355,091		583000	223,642
10		584000	556,317		584000	630,996
11		585000	389,312		585000	293
12		586000	1,946,369		586000	1,649
13		587000	1,041,969		587000	-
14		588000	4,473,218		588000	355,528
15		590000	13,853		589002	163
16		591000	13,423		591000	2,279
17		592000	858,946		592000	145,167
18		592010	297,099		592010	53,695
19		593000	3,793,593		593000	3,101,244
20		593010	47,809		593010	131,564
21		593020	14,532		593020	4,581,179
22		594000	150,424		594000	213,544
23		595000	117,238		595000	61,352
24		596000	692,743		596000	538,028
25		597000	42,803		597000	2,090
26	Narragansett Electric Company Total		17,322,384	Narragansett Electric Company Total		10,144,597

Division Data Request 10-13

Request:

Referring to Exhibit NG-RLO-2, Page 21, please provide any cost-benefit analysis prepared by or for the Company that addresses the uncollectible mitigation program.

Response:

Please see Attachment DIV-10-13 for the requested information in FY2009 and FY2010.

In light of forecasts relating to commodity prices and bad-debt expense, each of these items were expected to continue to rise. As the economy began to decline, the Company determined it necessary to develop and implement a comprehensive bad debt mitigation plan. The plan was developed to include a proactive outbound calling program along with an increase in field activity. Company-wide for National Grid USA, the plan recommended spending an incremental $12 million, which was anticipated to mitigate the increase in bad debt by approximately $19 million in FY 2009 (fiscal year ending March 31, 2009) with FY 2010 mitigation of $58 million (fiscal year ending March 31, 2010). See Attachment DIV 10-13-1, which illustrates the costs and benefits of the four original initiatives. The bad debt mitigation or "savings" was expected to result from additional collections efforts, earlier service terminations for non-paying customers and a more stringent review of customers seeking service connections to reduce fraudulent identification. The implementation plan required enhancements to existing programs; improving results and eliminating barriers to success, along with expansion of programs to our entire service territory.

Also, please refer to internal memorandum provided as Attachment DIV-10-13-2.

Prepared by or under the supervision of: Rudolph L. Wynter, Jr.

Bad Debt Improvement Plan
FY 2009 Impact
($000)

	FY09 Cost	FY09 Reduction to Bad Debt
Field Collections	$7,700	$8,000
Outbound Calling	$3,025	$4,000
Account Initiation	$1,500	$2,000
Predictive Analytics (Behavioral Scoring)	$400	$5,000
Total	$12,625	$19,000

FY09 Cost By Company

	Field Visits	Outbound Calling	Account Initiative	Predictive Analytics	Total
KEDNY	550	150	700	0	1,400
KEDLI	550	75	100	0	725
KEDNE	200	150	300	0	650
NG NY	1,650	1,975	150	200	3,975
NG NE	4,200	600	150	200	**5,150**
RIG	550	75	100	0	725
Total	7,700	3,025	1,500	400	12,625

NGNE Detail

	Field Visits	Outbound Calling	Account Initiative	Predictive Analytics	Total	
Nantucket	200	50	20	20	290	**3,760**
Mass Elec	2,900	350	90	130	3,470	
Granite State	100	50	10	10	170	
Narragansett	1,000	150	30	40	1,220	
Total	4,200	600	150	200	**5,150**	

FY09 Reduction to Bad Debt By Company

	Field Visits	Outbound Calling	Account Initiative	Predictive Analytics	Total
KEDNY	600	200	900	0	1,700
KEDLI	600	100	100	0	800
KEDNE	200	200	500	0	900
NG NY	1,700	2,600	200	2,500	7,000
NG NE	4,300	800	200	2,500	7,800
RIG	600	100	100	0	800
Total	8,000	4,000	2,000	5,000	19,000

FY10 Reduction to Bad Debt By Company

	Field Visits	Outbound Calling	Account Initiative	Predictive Analytics	Total
KEDNY	2,175	550	2,375	0	5,100
KEDLI	2,175	275	275	0	2,725
KEDNE	725	550	1,325	0	2,600
NG NY	6,175	7,000	525	6,500	20,200
NG NE	15,575	2,150	525	6,500	24,750
RIG	2,175	275	275	0	2,725
Total	29,000	10,800	5,300	13,000	58,100
	3.625	2.700	2.650	2.600	

Bad Debt Improvement Plan
FY 2010 Targets
($000)

	FY09 Targets				FY09 Actual				FY10 Targets			
	Cost		Savings		Cost		Savings		Cost		Savings	
Field Collections	$	7,700	$	8,000	$	5,597	$	4,513	$	5,608	$	3,796
Outbound Calling	$	3,025	$	4,000								
Account Initiation	$	1,500	$	2,000	$	298	$	5,274	$	426	$	6,983
Behavioral Scoring	$	400	$	5,000	$	269	$	1,395	$	430	$	2,232
C&I Deposit Initiative	$	-	$	-	$	-	$	-	$	-	$	4,200
Debt Sale and Collection Initiative	$	-	$	-	$	267	$	400	$	400	$	600
Replevin	$	-	$	-	$	-	$	-				
Total	$	12,625	$	19,000	$	6,430	$	11,582	$	6,864	$	17,811

Potential Impact of the Global Credit Situation on US Bad Debt
September 2007
DRAFT

Summary
The purpose of this paper is to assess the potential impact of recent credit market unrest on bad debt and accounts receivable in the National Grid United States distribution business.[1]

Recent developments in the credit market are expected to increase bad debt and accounts receivable. Drawing inferences from recently published information and our own internal data suggests that the number of customers who are behind in payments could increase between 8% and 20%. The increase in customers who fall behind in payments will initially increase accounts receivable and eventually increase charge off accounts. Existing accounts receivable total approximately $1.2 billion and annual bad debt is approximately $159 million

We expect to see an increase in the number of customers in collections, not necessarily the amount owed by existing customers who are already in arrears. We also expect the new customers to be primarily homeowners, due to the increase in mortgage payments driven by variable rate mortgage re-pricing.

In addition to the expense associated with increased uncollectible accounts we will need to plan on funding more O&M for operational transactions to mitigate financial impacts. More field visits, more outbound calling, more mailed notices and more inbound calls are expected as a result of the increase in the number of collections customers. Other mitigation strategies must also be evaluated but reliable cost estimates are not available at this time.

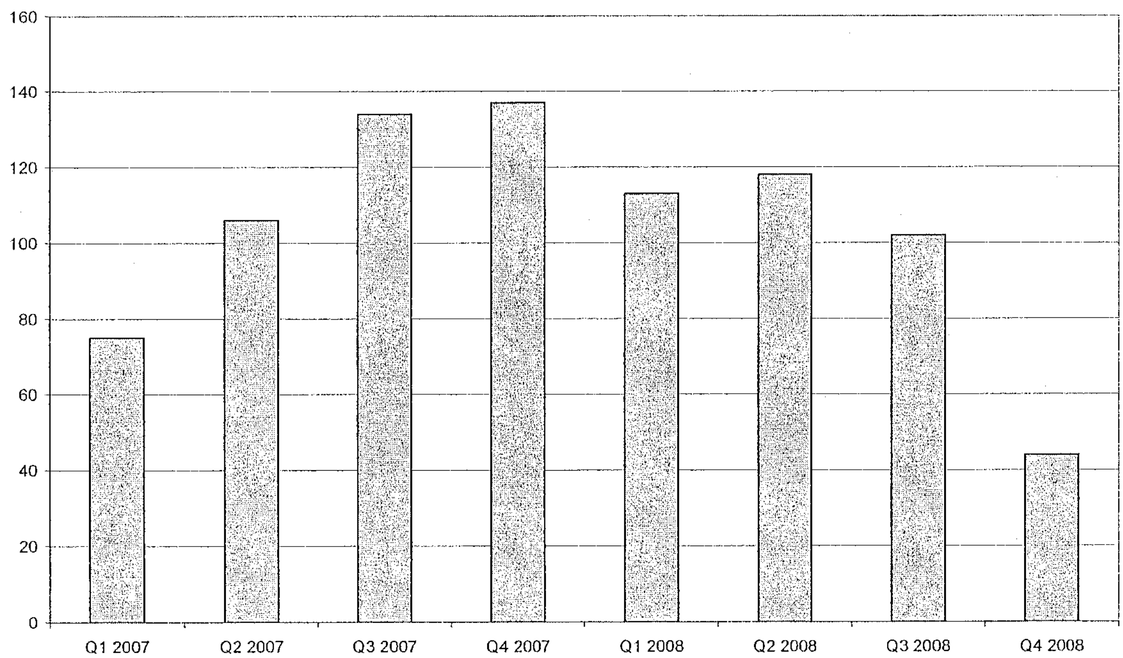
Defining the Problem
The re-pricing of variable rate mortgages is expected to be the biggest driver of bad debt challenges in the United States distribution business. More than 50% of the mortgages written in recent years have been variable rate and many of them have been sub-prime or Alt-A mortgages. Both sub-prime and Alt-A mortgages are generally more risky because they were given to customers who had questionable credit or were not required to provide documentation of their credit worthiness. Variable rate loans written in the past 2-5 years are approaching the first re-pricing timeframe. One rule of thumb is that mortgage holders can expect monthly mortgage payments to increase by $200 for every $100,000 in debt after the rate is reset.

The table below shows the relative amount of mortgage debt that reaches the first re-pricing period for each quarter of 2007 and 2008. Mortgage re-pricing will peak in the fourth quarter of 2007. After re-pricing we expect a lag of one month to several months for customer payment behavior to deteriorate. Although some small impact of the credit market unrest is surely already in our numbers we have not yet seen the worst. We expect the peak of impact to lag the peak of re-pricings by several months.

The broader market has already started to see the impacts of recent developments:

- Mortgage delinquency rates are nearly 3.25%, an increase from the recent historical average of around 2.25%.
- Eastern and Central Massachusetts and Long Island have seen some of the highest increases in mortgage delinquency in the country.
- Automobile loan delinquency is now around 3.1% and is forecast to increase to nearly 3.5% over the next 3 years.
- Credit Card delinquency is expected to grow from the current rate of around 3.5% to more than 5.0% over the next 2-3 years.
- Consumer financing delinquency is expected to increase from just over 5.5% to more than 7.5% over the next 2-3 years.

Mortgage Debt Outstanding Facing First Payment Re-Pricing
(US$ Billions)



Customers who will be most impacted by mortgage re-pricing are not traditionally customers who have payment troubles. Typically, homeowners experience less than half the delinquency rate of renters and the majority of charge offs originate with customers who rent. Our existing tactics are tailored to identify and address historical collections customers. New plans must be developed to first identify new customers who are likely to become delinquent in payments then implement methods that are likely to be effective at resolving the delinquency.

Geographic Scope of the Impact
The impact of mortgage re-pricing is expected to be greatest in those areas where property values have seen the greatest gains in recent years. The impact on New England, New York City and Long Island is expected to be greater than the impact on upstate New York. Lower home prices require smaller mortgages and therefore smaller increases due to mortgage re-pricing. This advantage will be partially offset by relatively lower average wages in upstate New York resulting in a lower tolerance for increased payments..

Estimated Impact – Residential (Domestic) Market
The estimate of the size of the impact was determined using data from our upstate New York service territory. Although it is expected to be least impacted, we have the best data and easiest access to data for this territory due to the processes and system used to store information. One shortcoming of this approach is that we must assume that all other territories are similar to upstate New York.

Adjustable rate mortgages gained popularity beginning approximately 5 years ago. Since then over half of all mortgages in the US have been adjustable rate. To estimate the size of the population that could be effected by re-pricing we observed all accounts that connected service in the past 5 years. Of the nearly 1.5 million customers in upstate New York, 613,000 have connected in the past 5 years. Of the recent connects, 298,000 own their property. It is important to point out that this data is self-reported by customers and is not verified by the Company. Approximately 52,000 of the new connected customers who own their property are already in arrears, leaving a population of 246,000 owners who connected in the past 5 years and are not already in arrears.

2.05%

5.73%

Assuming that 50% of these owners financed their purchase with a variable rate loan we can calculate that 123,000 are subject to re-pricing. Some proportion of customers who experience a re-pricing will encounter payment troubles. We have no strong basis to establish a reasonable range so we assumed that 20% to 50% of customers who experience a re-pricing will eventually experience payment trouble with National Grid. This range yields an increase of 25,000 to 62,000 customers experiencing payment troubles. There are currently 310,000 customers with payment trouble, so we can estimate an increase of 8% to 20%. This change is driven by a fundamental shift in the underlying economy and would persist until a broad solution to the credit unrest is implemented.

The assumption must be made that all US service territories exhibit similar characteristics to scale this estimate. There are almost certainly differences but no reliable data exists to measure the differences between service territories in the near term.

Renters are explicitly excluded from this estimate. Some softening of rental rates might help the underlying financial outlook for renters but no estimate has been prepared.

The table below shows the calculation of the range of impact:

			Metric
Customers			1,463,563
Connects in past 5 years			613,230
New connect owners			298,011
New owners already in collection			51,985
New owners not in collection			246,026
Percent with variable rate mortgage			50%
Potential facing re-pricing			123,013
Range of customers experienceing payment trouble			
	High	50%	61,507
	Low	20%	24,603
Existing Collections Customers			309,775
Percent Increase in Customers in Collections		High	20%
		Low	8%

Estimated Impact - Non-Residential Market

No specific estimate was prepared for the potential impact on the non-residential market. Two primary factors will impact the non-residential customer payment behavior. First, it is more difficult to raise capital in the current environment. Customers who experience temporary cashflow challenges will find it more difficult to access credit markets and survive. Second, more non-residential customers, especially restaurants and other providers of non-essential goods and services will see fewer customers as residential customers cut back to meet rising mortgage payments. This assumption is borne out by recent decreases in demand for automobile loans. Automobile loan growth rates are below 5% in recent months when the average growth rate over the past five years has been 10%. Customers are already deciding to delay large purchases in reaction to increased mortgage payments.

Without better information, we will assume that the impact on non-residential customers will mirror the impact on residential customers and result in an increase of 8% - 20% in the number of customers in collections.

Mitigating Impacts

To mitigate the potential impact on accounts receivable and bad debt we must plan on increasing the number of transactions with customers. Several areas will need to be increased:

- More outbound calling should be scheduled. Outbound calling is among the least expensive and most effective methods of reducing accounts receivable.

- More notices will be mailed to delinquent customers. Regulations require that we send disconnect notices prior to field treatment and other notices are mailed to attempt to prompt a payment.
- More inbound collections calls will be received as we make more outbound calls and send more notices.
- More field visits will be need from the Metering Services organization. The number of incremental field visits will be determined by the number of incremental customers in collections as well as the success rate of our mitigation strategies.
- Customers who have never before been in collections will now find themselves having trouble paying their bills. Our analytical processes are based on historical behavior, so our model's ability to predict behavior will decrease as more new customers enter collections. We find more success in resolving arrears when we can intervene early in the delinquency cycle. We need to evaluate working with a third party who has access to more data and more advanced models to help find better ways of predicting payment behavior and developing more effective treatment strategies.

Conclusion

The recent credit market unrest will likely increase the number of accounts that experience payment trouble, increase accounts receivable and ultimately increase bad debt. An increase in the number of accounts in collections will lead to an increase in accounts receivable and charge off expense of similar magnitude. The credit market unrest will cause a step change in the economy. The impact on bad debt and accounts receivable will persist until the underlying issues are mitigated. The ability to accurately forecast the impact is limited due to lack of data and the fact that this situation is unprecedented so we do not know how customers will react.

Applying an increase of 8% - 20% to bad debt yields an annual expense increase of between $13 million and $32 million.

Mitigation strategies will require increased levels of transactions with customers and potentially the assistance of outside data providers and analytical resources.

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[1] Determining the impact on bad debt is an inexact science. Access to reliable data is the largest challenge we face in developing an accurate forecast. The second biggest challenge is understanding how customers will react to a significant change in their financial condition.

Credit and Collection Strategy Discussion

January 2008

SharedServices
One company, one way

nationalgrid

Agenda

- History and Background
- Value Levers
- Current Landscape
- Project Priority
- Resourcing Plan

History and Background

- Predecessor companies have been down a process improvement path:
  - *National Grid – Credit and Collection Process Improvement Project (CCPIP) 2002-2003*
  - *National Grid – Bass & Co. Review 2004*
  - *KeySpan – Business Transformation (BT) 2004*
- CCPIP
  - *PA Consulting was engaged to review the entire C&C business*
  - *Resulting process changes impacted all major functions*
  - *Improvement of approximately $20 million realized.*
- Bass & Company
  - *Focus was on strategic deployment of technology and sourcing of transactions to minimize cost and maximize effectiveness.*
- BT
  - *Changes to the credit matrix to better recognize risk.*

Value Levers

Practices

- Account Initiation
  - Pos ID
  - Unpaid Bills
  - Residency
- Account Management
  - Segmentation
  - Outbound Calling
  - Litigation Strategy
  - Maximize HEAP
- Field Collections
  - Access Issues
- Final Bills
  - Contract Structure
  - Debt Sale

Transaction Volume

- Outbound Calling
- Field Visits
- Access Resolution
- Litigation

Regulatory Framework

- Challenges to practices
- Rule reviews
- Advocacy intrusion
- Contractual changes
- “Requests” to be lenient
- Recovery Mechanism

System Enhancements/Add-Ons

- Predictive Analytics
  - Reduces volume by focusing on best actions
  - Speed to treat through better predictive ability

Current Landscape - Practices

The current businesses have different practices:

	Account Initiation	Account Management	Final Bills
NGNY	•Fundamentals in place. •Better technology needed to increase hit rate.	•CSS offers good basics. •Better technology can provide earlier action and eventually minimize transaction cost.	•KeySpan vendors charge more but provide greater net return. •Pilot program needed to validate if underlying practices are driving the incremental returns, or if the difference is real. •Vendor consolidation should provide cost savings and may provide superior return.
NGNE	•Fundamentals developing. •Better technology needed to increase hit rate.		
RIG	•Fundamentals in place except residency. •Better technology needed to increase hit rate. •CSS will help.		
KEDNY	•Fundamentals lacking •Pos ID pilot	•CRIS offers good basics •Would benefit from CSS or newer technology.	
KEDNE			
KEDLI		•CAS is least sophisticated, least flexible system (first generation)	

Current Landscape – Transaction Volume

	Outbound Calling	Field Collections	Access Resolution	Litigation
NGNY	•One campaign active. •Need measurement capabilities •Sourcing benefits.	•Requesting more. •Resource constrained in the past. •Difficult to adjust quickly. •Consistency is important.	•Replevin • *Need automation to drive efficiency/consistency* • *More volume needed.* •Pole/Curb • *Insufficient/inconsistent volume*	•Fledgling program •Need automation and increased volume.
NGNE	•Three campaign active. •Good measurement capabilities in past (losing with CSS) •Need to refresh the campaigns.		•Replevin • *Cumbersome court process needs out-of-the-box legal review* •Pole/Curb • *Insufficient/inconsistent volume*	• Good volume, but manual program, needs automation.
RIG	•Basic campaign active. •No robust measurement of results.		•Replevin • ***No statutory authority*** •Curb Valve Installs • ***Insufficient/inconsistent volume***	
KEDNY	•Several campaigns active. •Infrequent recalibration. •No robust measurement			•Good program •Good Tracking •Needs automation
KEDNE				
KEDLI			•Fledgling program	•Fledgling program

Current Landscape – Regulatory Framework & Systems

- Regulatory Framework
  - *New York*
    - *PULP Challenging right to collect 100%*
    - *HEFPA SAPA notice*
    - *HEAP contract*
    - *LICAP discussions*
  - *Massachusetts*
    - *Democratic administration and new Commissioners*
      - *More vocal/involved advocacy groups*
    - *LIHEAP changes*
    - *Recent legislation*
  - *Rhode Island*
    - *Contradictory Staff Positions*
    - *Very active advocacy group*
    - *Legislators willing to pass emergency measures*
    - *Erosion of reconnect rights*
  - *New Hampshire*
    - *Gas rate case*
  - *Overall – Strategy for recovery of bad debt costs*

- Systems
  - *CSS*
    - *Offers solid basic capabilities*
    - *Opportunities to improve using existing framework*
  - *CRIS (KEDNY/KEDNE)*
    - *Slightly less sophisticated than CSS*
    - *Limited opportunities to improve*
  - *CAS (KEDLI/LIPA)*
    - *Least flexible system*
    - *Significant issues around account management and data availability*
  - *CIS & Advantage (NGNE/RIG)*
    - *Soon to be replaced*

Project Priority

Practices

- Account Initiation
  - Pos ID
  - Unpaid Bills
  - Residency
- Account Management
  - Segmentation
  - Outbound Calling
  - Litigation Strategy
  - Maximize HEAP
- Field Collections
  - Access Issues
- Final Bills
  - Contract Structure
  - Debt Sale

Opportunities

- Install Pos ID
- Enhance data stream for Pos ID (Data Sourcing)
- Enhance Matching Capabilities (Data Hygiene)
- Institute Residency in areas where it is allowed
- Recall past debts from vendors
- Enhance the ability to measure outbound results.
- Sourcing of outbound for cost savings
- Automate litigation process and measurement
- Market to potential HEAP Recipients
- Move meters outside
- Install remote disconnect devices
- Re-engineer replevin to make it more effective
- Review NE warrant process to determine if we can streamline the court process.
- Pilot to understand differences between KS/NG final bill vendors
- Sell debt after tertiary level
- Consolidate final bill vendors

Project Priority

Transaction Volume

- Outbound Calling
- Field Visits
- Access Resolution
- Litigation

Opportunities

- Increase outbound in upstate New York
- Sourcing of outbound for cost savings
- Increase use of litigation
- Increase pole/curb cut volume and consistency
- Increase the number of curb valves installed

Project Priority

Regulatory Framework

- Challenges to practices
- Rule reviews
- Advocacy intrusion
- Contractual changes
- "Requests" to be lenient
- Recovery Mechanism

Opportunities

- Clarify internal stakeholders
- Clarify who provides guidance
- Establish regulatory attorney access
- Regular interface with regulatory team and clear expectations.

Project Priority

System Enhancements/Add-Ons
•Predictive Analytics •Reduces volume by focusing on best actions •Speed to treat through better predictive ability

Opportunities

- Evaluate and purchase predictive analytics

Project Priority - Practices

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Pos ID	Install positive identification at KED.	KEDNY, KEDLI, KEDNE	$3.8 million	Minimal	Medium	1-2 years
Data Sourcing	Install enhanced matching capabilities to reduce BO exceptions.	NGNY, NGNE now; RIG post CSS; KED after rollout of common system	Medium/High	Low	High	1-2 years
Data Hygiene	Install enhanced matching capabilities to speed transaction time and increase hit rate.	NGNY, NGNE now; RIG post CSS; KED after rollout of common system	Medium/High	Low	High	1-2 years
Institute proof of residency in RI	Use full extent of rules in RI.	NGNE, RIG	Medium/Low	Medium	High	1-2 years
Recall past obligations	Institute a program to recall from Final Bill vendors.	KEDNY, KEDL!, KEDNE	$0.5 million	Minimal	Medium	12-18 months

Project Priority - Practices

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Measure OB Results	Develop a robust outbound performance measurement system	All – need to span 4 different customer platforms	Medium	None	Medium/High	1-2 years
Outbound Sourcing	In-house/ Outsource optimization for operational savings	All	Low/Medium	None	Medium/Low	1 year
Automate litigation	Deploy an integrated and automated litigation management system to speed the evaluation and tracking of accounts	All	Low	None	Medium/High	1-2 years
Maximize HEAP	Enhance marketing efforts to potential HEAP recipients	KEDNY, KEDLI (NGNY?)	$1.5 million	Positive	Low	12-18 months
Move meters outside	Identify worst offending premises and pay contractors to move meters outside	All	Low/Medium	Medium	Medium	2-3 years

vices

nationalgrid

Project Priority - Practices

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Move meters outside	Identify worst offending premises and pay contractors to move meters outside	All	Low based on volume	Medium	Medium	1-3 years
Remote disconnect technology	Install remote disconnects in worst offending premises	All	Medium	Low (NY High)	Medium	1-3 years
Re-engineer replevin	Make the process consistent, consolidate vendors, automate and streamline	All, different by state	Medium	Low	High	1-3 years (Some improvement is shorter term)
Review NE warrant process	Legal review to streamline	MA	Low	Low	Low	6-12 months
Pilot final bill vendors	Run a pilot to verify differences in performance and choose the best vendors	All	Potentially worth \$3.7 million annually	None	High	1-2 years

Project Priority - Practices

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Sell debt	Debt sale after tertiary level	All	$0.9 million	None	Medium	12-18 months
Deposit policies	Adopt consistent AI and delinquency deposit policies where allowed by regulation	All	$1.7 million	Low	Low	12-18 months
Non-Residential account management	Migrate to better NR practices	KED, RIG, NGNE	$0.7 million	None	Medium	12-18 months
Improve payment agreement performance	Change policy on NR DPA's	KED	$0.8 million	None	Medium	12-18 months
Institute Collection Fees	Charge a fee for every field visit to a non-residential customer	NG	$1.9 million	Medium	Medium	12-18 months

Project Priority – Transaction Volumes

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Outbound Calling	Increase OBC volume in Upstate NY	NGNY	$4.4 million	Low	Medium	18-24 months
Field	Increase field an average of 20%	All	$	Medium	High	1-3 years (Some is immediate)
Access Resolution	Increase replevin, warrants, installation of curb valves, curb and pole cuts	All	Medium	Low	High	1-3 years
Litigation	Increase litigation volume for accounts that do not pay and are difficult to terminate	All	Medium	None	Medium/High	1-3 years

Project Priority – System Enhancements

Project	Description	Company Impacted	Value	Regulatory	Effort	Timing of Savings
Predictive Analytics	Procure advanced analytical services to better prioritize accounts and activities. Savings include better speed to treat risky accounts and operational savings in the long run	All	High	Low	High	2-4 years

Resourcing Plan

- ***Current staff is fully engaged in existing control functions, regulatory oversight and operating the business.***
- ***Project list represents a significant level of change, especially any technology related item that spans more than one system.***
- ***Incremental staffing is required to implement.***
- ***Need***
  - Skills assessment of projects – what do we need to implement successfully?
  - More detailed baseline of the existing capabilities
  - Augmentation plan – use of consulting resources
  - Project management framework to allow involvement and oversight for the existing managers

Resourcing Plan

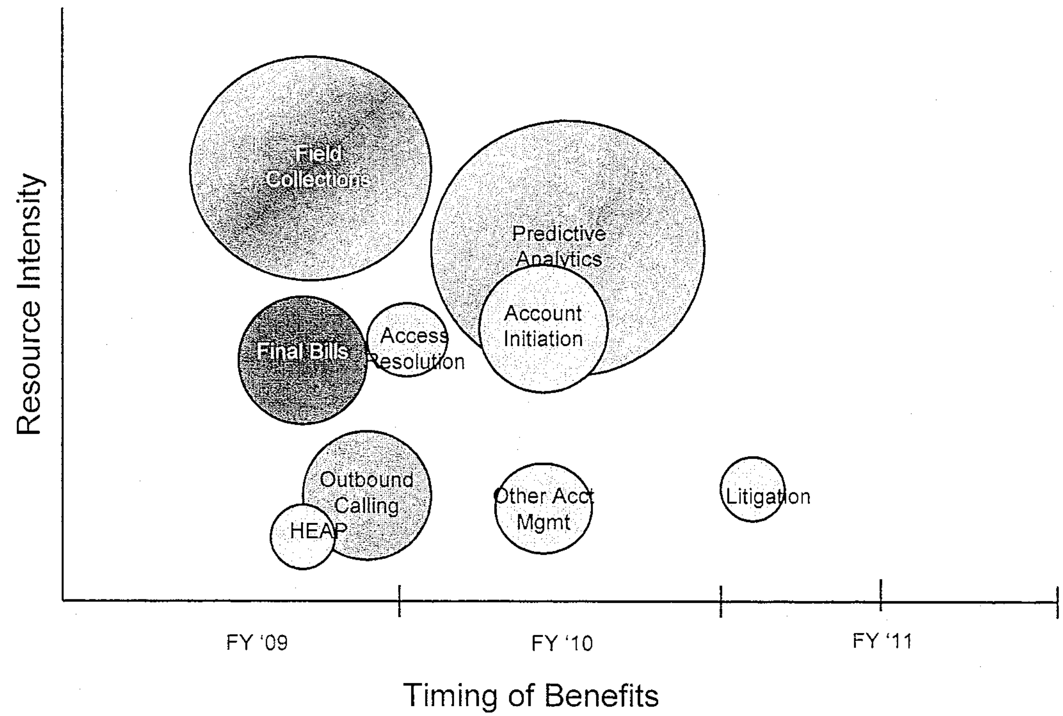
- *Near Term – Consultant to help assess and prioritize*
- *Next – Augment staff with consulting/project management resources*
- *Also – Hire incremental internal staff to use this as a training opportunity*

Bad Debt Briefing Paper

Initial projections for FY 2008-09 are significantly increased from central case:

	FY ' 09 Hyperion	FY '09 First Look	Variance
NG NY Electric	43.5	51.0	(7.5)
NG NY Gas	17.4	20.7	(3.3)
NG NE - Electric	37.5	62.9	(25.4)
NG NE - Gas	9.9	12.1	(2.2)
KEDNY	0.0	0.0	0.0
KEDNE	0.0	0.0	0.0
KEDLI	0.0	0.0	0.0
Total	108.3	146.7	(38.4)

Several initiatives to improve performance:



Regulatory Strategy:

Developing plans to seek recovery of commodity portion of bad debt.

FY 2008-09 Budget

Bad Debt Improvement Plan

Spending by Organization

	GBU	EBU	Shared Services				
	Customer Metering Services	Contact Center	Credit & Collections	Facilities	Total SS	Information Systems	Total
Field Collections	**$4,700**	**$1,200**	**$1,700**	**$100**	**$1,800**	**$0**	**$7,700**
Outbound Calling							
Increased Calls	$0	$1,700	$0	$0	$0	$0	$1,700
Perf Mgmt`System	$0	$0	$100	$0	$100	$400	$500
Sourcing	$0	$75	$0	$0	$0	$750	$825
Sub-Total OBC	**$0**	**$1,775**	**$100**	**$0**	**$100**	**$1,150**	**$3,025**
Account Initiation							
Positive ID	$0	$400	$600	$0	$600	$0	$1,000
Adata/Sourcing/Hygiene	$0	$0	$200	$0	$200	$0	$200
Residency	$0	$0	$0	$0	$0	$0	$0
Recall Past Obligations	$0	$300	$0	$0	$0	$0	$300
Sub-Total AI	**$0**	**$700**	**$800**	**$0**	**$800**	**$0**	**$1,500**
Predictive Analytics	**$0**	**$0**	**$250**	**$0**	**$250**	**$150**	**$400**
Grand Total	**$4,700**	**$3,675**	**$2,850**	**$100**	**$2,950**	**$1,300**	**$12,625**

KeySpan

Expected Savings

Year One Bad Debt Savings By Company and Initiative
Fiscal Year 2008/09

	KEDNY	KEDLI	KEDNE	NGNY	NGNE	RIG	Total
Field Visits	$0.6	$0.6	$0.2	$1.7	$4.3	$0.6	$8.0
Outbound Calling	$0.2	$0.1	$0.2	$2.6	$0.8	$0.1	$4.0
Account Initiation	$0.9	$0.1	$0.5	$0.2	$0.2	$0.1	$2.0
Predictive Analytics	$0.0	$0.0	$0.0	$2.5	$2.5	$0.0	$5.0
Total	**$1.7**	**$0.8**	**$0.9**	**$7.0**	**$7.8**	**$0.8**	**$19.0**

National Grid Outbound Calling Campaign Objectives

Required resolutions opt out options:

- *Full Payment of arrears: Pay by Phone option:* This is a crucial option in that it provides the customer an instant method to make a payment. This eliminates the need for a customer to locate a payment agent, travel and then call back in to the center with a receipt number. This option also eliminates an inbound call.

- *Establish an agreed upon collection arrangement (standard agreement option is available in Grid IVR):* This option also allows an instant method of treatment. The collections functionality of our IVR will analyze the account to determine if it is eligible for our standard offer. Customers not eligible for our standard will be transferred to a live agent to establish a payment agreement

- *Transfer to live agent to establish an agreed upon payment agreement:* This option may also provide an instant method of treatment if the customer is willing to accept our terms. (Does the agent have the ability to take a down payment by CC over the phone?) (Do we want provide a live opt out anytime throughout the call?)

- *Provide access to local pay agent listings:* This is a link to our IVR. This option may result in an inbound call as the customer should be calling back in with a receipt number.

- *Provide proper connectivity to DSS or other special protection units:* This option will work similar to our payment agreement option in the IVR. (If this option is not available, how do we treat special protections?)

- *Ability to perform our 72 Hour Notice calls:* These are live calls that utilize a live agent and an automated dialer. Upon connection with the customer a live rep will handle the call to completion. These calls are performed during our winter collections moratorium period.

Basic requirements:

- *Capture correct phone number if provided:* The need for this requirement may be greatly reduced once our data hygiene program is active. Previously it was an option within our OBC campaigns.

- *File needs to be available for our nightly batch run by 2030:* Prime calling time is from 7-9pm. Due to the scheduling of our nightly batch the return call file need to be received by National Grid IS by 8:30pm each night. This requirement cuts into prime calling time for vendors as they currently stop calling at 7:30 pm in order to compile and transfer the file to us by 8:30.

- *Have the ability to toggle on or off the option of leaving an answering message:* This option provides us flexibility when we may have insufficient resource to handle expected inbound traffic.

- *End of day reporting must include number of each resolution option broken out by company code:* End of day reporting is a dynamic effort that will go through many changes over the next 18-24 months. If a vendor is selected to run this campaign they must be willing to work with the business owners to develop comprehensive reporting data. National Grid will expect any chosen vendor to facilitate in developing a comprehensive reporting system.

- *Assistance and simplicity in "tweaking" the scripts in order to determine the best wording, voice and delivery of our messages:* National Grid will rely on any chosen vendors experience to aid in "tweaking" our call scripts, depending on changes in wording and tone to most effectively deliver our message and prompt customer action to the underlying collections issue.

- *Speed to implement the needed campaigns:* National Grid management has set ambitious goals of ramping up our OBC efforts. Speed to implement the campaigns is crucial at this time and this factor is weighted heavily in our scoring of options as these call campaigns are a key part in our strategy to reduce delinquent AR.

- *Minimal FTE touching to manage, maintain the campaign:* The central idea of OBC is to make this as much an automatic process as possible. This no-touch goal is true both on the messaging portion as well as on the treatment options available to the customer. The outbound effort must require absolute minimal effort to implement and maintain, while inbound calls must be minimized by offering self serve options.

- *Verify correct customer:* This front end function expedites the collection process by identifying the customer based on ...., and queries CSS to determine available treatment options.

- *Provide one touch options to customers to navigate throughout the script to expedite resolution:* Standard functionality with the ability to opt to live agents or to "drop" into the National grid IVR at the appropriate module, thereby bypassing the front end messages and verification.

Strategic Alignment: The OBC campaigns are a key element in the group strategy to eliminate delinquent AR. By reaching out to customers with these low cost calls we expect to improve collections flow (by eliminating $40m of bad debt _quantify). The primary campaigns in the legacy NY and NE territories are currently defined as:

- **Reminder calls:** For most accounts (not all accounts receive reminder calls based on their ICR and previous collections history with National Grid) that enter collections this will be the first noticing the customer receives. These calls are made shortly after an account enters collections. Currently 3 call attempts (with a message being left on the 3rd attempt, if applicable) are made within days of the account entering the call file. The script is straightforward asks for immediate resolution to an overdue balance. Treatment options include standard offer arrangements, minimum payment agreements, and special protections assistance for those that qualify. The current reminder scripting does not provide an option for the customer to opt out to the IVR or to a live agent.
- **Disconnect Notice calls:** When previous collection efforts fail to place the account in an appropriate treatment path a Disconnect Notice is issued. At the time of this notice being sent to the customer, warning of the chance of termination of service, an OBC will be generated. This message is a bit more urgent in nature and informs the customer that they risk termination of service if immediate attention is not brought to this matter. Treatment options remain the same as with the reminder calls.
- **Other campaigns:** Currently NY has 3 other campaigns mapped in its 1043 collection table. These calls are:
    - Post Notice calls:
    - Defaulted Payment Agreement calls:
    - 72 hour calls:

Production Analysis: We are currently developing the foundation of a reporting tool to fully understand the effectiveness of these campaigns. An Access database is being developed that will dissect the daily results of our OBC's. The first phase of the tools development is looking at the percentages of successful calls that result in treatment of the account within 3, 5 or 10 days from the date called. The treatment paths utilized will be archived, the amount paid as a percentage of arrears will be closely monitored to determine which treatment path results in the most arrears collected. The data will be scrutinized by operating center, ICR, age of arrears, amount of arrears and multiple other variables until we fully understand the impact our OBC efforts have on delinquent AR. Currently this tool is being built by the collections group but IS support may be needed to divide the daily call file in order to expedite the reporting process.

- Data from the past four weeks of our OBC's shows that 54% of successful calls resulted in payment within 10 days form the date of the OBC.
- 41% of unsuccessful calls resulted in a payment within 10 after the date of the call.
- The amount of suspends placed on accounts that had unsuccessful calls is much larger than that of successful calls. This indicated that we may be getting the customers attention without recording a successful call.

Flexibility: A thorough analysis of each day's activity will help us understand the effectiveness of our calls. Once we are confident we have enough solid data to serve as a baseline we intend to utilize our vendor's expertise or other outside sources to fine tune our messaging. Enhancements may come in the forms of script changes, changes in tone and delivery, the timing of our calls or even the addition or removal of campaigns as our analysis dictates. We will rely on a platform that is quick, easy and inexpensive to manipulate in order to make changes to our campaign.

Operational Excellence: The alignment of this campaign with group strategic goals, supported by a comprehensive statistical analysis plan and a flexible platform will result in a program that will prove itself to be of high value within the organization. Other programs underway within the group will surely support and enhance the effectiveness of our efforts. The data hygiene project will give us a much better understanding of who our customers are and will make it easier to maintain contact with delinquent customers. We currently have a moderate percentage of accounts that do not get called due to bad phone numbers. The data hygiene project will help reduce this error rate. The PMP project will determine the most effective collections treatment for each delinquent customer based on a proven methodology provided by the global leader in risk scoring. Getting higher risk customers into a viable treatment path sooner than we currently do is a staple of the overall collections process overhaul. Early identification and treatment of these accounts with low cost call campaigns is the most cost effective route for the company to collect its delinquent AR as this approach is nearly fully automated.

Economic Value Added: Increased revenue will be apparent immediately as the reminder calls were not being made in NE until mid May of 2008. Currently the effort is underway to launch the disconnect call campaigns in legacy National Grid territories of Upstate NY and NE. Estimated call volume is approximately 15,000 call per day for the disconnect notice calls.

Division Data Request 11-2

Request:

Page 4, lines 14-18: Please describe in detail the "public policies and legislation" that is referenced. Indicate whether these policies and legislation impose any new requirements on National Grid, as opposed to desirable goals. Also describe the "new distribution technologies" referenced and specifically indicate whether National Grid is proposing to implement such specific technologies in its plans that are described in its filing in this document. Finally, describe the substantial investment by electric distribution companies needed to support efforts on climate control and environmental issues, and indicate whether National Grid has included the costs and benefits of the investments in its filing in this proceeding.

Response:

Below are a few examples describing public policy and legislation advancing the implementation of new distribution technologies requiring substantial investment by the Company. Please note that the Company is not making any proposal for cost recovery associated with these times in this filing.

Department of Energy - 10 CFR Part 431, Energy Conservation Program for Commercial Equipment: Distribution Transformers Energy Conservation Standards;

The final rule sets minimum energy-efficiency standard levels for liquid-immersed distribution transformers and medium-voltage dry-type distribution transformers. The final rule revises efficiency standards previously proposed in DOE's Notice of Proposed Rulemaking (NOPR) published August 4, 2006, and clarifies certain other requirements.

Comparing efficiency levels to those contained in the NOPR, levels for all single-phase transformers and three-phase transformers from 750 kVA through 2500 kVA increased substantially. Levels for three-phase transformers from 15 kVA through 300 kVA remained unchanged, and the level for 500 kVA three-phase units is slightly lower. Howard Industries is studying the final rule to determine the expected impact on the transformer industry.

Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) provides states with a mechanism to increase renewable energy generation using a cost-effective, market-based approach that is administratively efficient. An RPS requires electric utilities and other retail electric providers to supply a specified minimum amount of customer load with electricity from eligible renewable energy sources. The goal of an RPS is to stimulate market and technology development so that, ultimately, renewable energy will be economically competitive with conventional forms of

Division Data Request 11-2 (cont.)

electric power. States create RPS programs because of the energy, environmental, and economic benefits of renewable energy and sometimes other clean energy approaches, such as energy efficiency and combined heat and power (CHP).

NERC (North American Reliability Corporation

NERC reliability standards define the reliability requirements for planning and operating the North American bulk power system. NERC's ANSI-accredited standards development process is defined in the Reliability Standards Development Procedure and is guided by reliability and market interface principles. The Reliability Functional Model defines the functions that need to be performed to ensure the bulk electric system operates reliably, and is the foundation upon which the reliability standards are based.

Prepared by or under the supervision of: John Pettigrew

Division Data Request 11-20

Request:

Does Narragansett Electric own any transmission assets? If so, please describe these assets, and indicate whether any of these assets have been approved by ISO-NE as PTF facilities.

Response:

Narragansett Electric Company owns transmission assets. At calendar year-end December 2008 per the FERC Form 1 report, Narragansett Electric Company had $237.4 million of transmission assets on its books, of which 72 percent of those assets or $170.9 million were classified as Pool Transmission Facilities (PTF). Attachment DIV 11-20-1 illustrates the relationship between the $237.4 million per the FERC Form 1 and the rate base amount of $235.8 million included in the Company's cost of service on Schedule NG-RLO, Page 31, Line 1.

Narragansett Electric Company electric assets are defined to be Distribution or Transmission assets per the 7 Factor Test, as approved by FERC in Docket ER97-680-000, and included as Attachment DIV 11-20-2. Any transmission asset that meets the definition, as shown in Attachment K of the ISO-NE Tariff (and included as Attachment DIV 11-20-3), are classified as PTF unless otherwise found to be treated as non-PTF localized facilities through the review done through ISO-NE Transmission Cost Allocation process (TCA).

Line		Dec 2008	
1	Plant in Service		
2	Transmission Plant in Service	$ 237,350,851	1/
3	General Plant in Service	1,409,963	2/
4	Subtotal IFA Plant in Service	238,760,815	
5			
6	Less Tower Hill Reclass	(2,927,735)	3/
7			
8	Total IFA Plant in Service	$ 235,833,080	4/

1/ Agrees to response to DIV 11-20 and Workpaper NG-RLO 2, Page 4
2/ Agrees to Workpaper NG-RLO 2, Page 4
3/ Agrees to Workpaper NG-RLO 30
4/ Agrees to Schedule NG-RLO-2, Page 31, Line 1

Table of Contents

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

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

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

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

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

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

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

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

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

the local distribution.

(7) Local distribution systems will be reduced voltage.

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

II. Summary of NEES System Structure

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

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

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

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

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

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

III. Description of the NEES Retail Companies' Distribution Systems

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

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

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

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

IV. Application of the Seven Factors

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

V. Description of the NEES Transmission System

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

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

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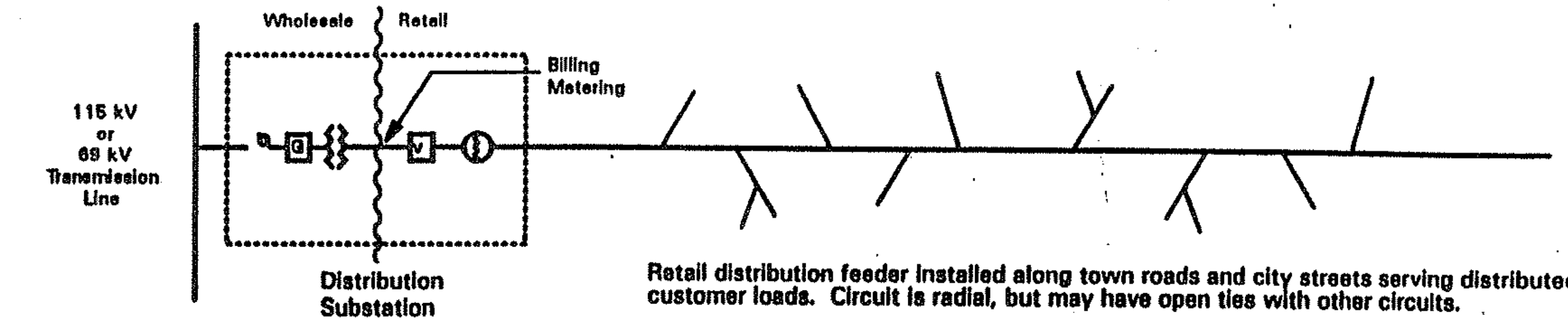
[5] Two limited exceptions relate to Narragansett ownership of two 23 kV transmission interconnections that allow Pawtucket Power and the Johnston Lanfill IPP projects to sell power from their facilities at wholesale.

VI. Conclusion

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

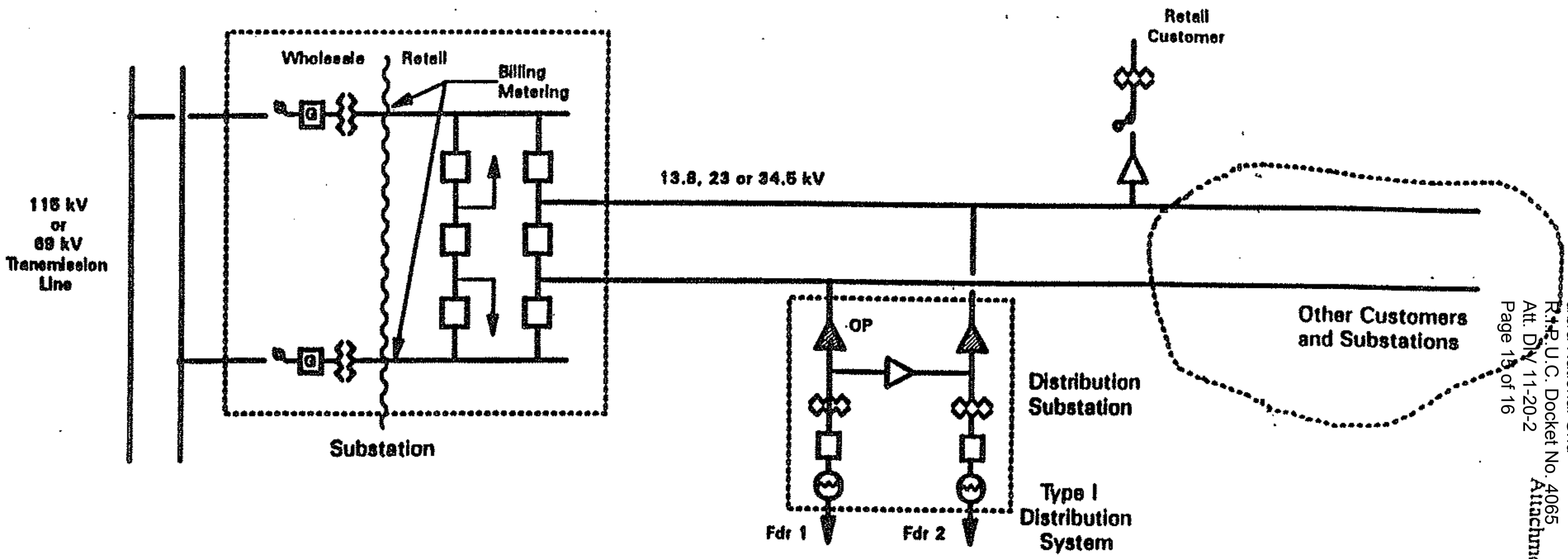
TYPICAL LOCAL DISTRIBUTION SYSTEMS
VOLTAGE CLASS: 5, 15, 25, 34.5 kV

Type I Distribution System



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

Type II Distribution System



A typical type II distribution system will emanate from a transmission supplied substation, will be built along right of

THE NARRAGANSETT ELECTRIC COMPANY

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

SDP Standard Delivery Point
SL Supply Line

Division Data Request 11-25

Request:

Please provide actual spending and activity levels for Vegetation Management for the last five years. Include information on the use of contractor tree trimming crews and National Grid employees.

Response:

Please refer to Attachment DIV-11-25 for a listing of Vegetation Management spending levels for the past five years. Please note that the Company contracts for tree trimming crews and does not use in-house resources for these activities in Rhode Island.

Prepared by or under the supervision of: John Pettigrew

Actuals CY 05 - CY 09
Distribution Veg Mgmt REP View - Rhode Island

$'000	CY 05 Actuals	CY 06 Actuals	CY 07 Actuals	CY 08 Actuals	Thru June CY 09 Actuals
OPEX - VM					
Cycle Trimming	2,492,850	3,472,306	4,702,319	4,428,539	2,902,582
Hazard Tree On-Cycle	116,407	179,124	183,945	191,935	90,456
Hazard Tree Off-Cycle			234,194	838,566	23,865
Worst Feeders			12,780	-	-
Interim/Spot Trim	165,504	133,052	131,288	163,775	27,988
Sub-T (on-road and off-road costs)	44,006	259,405	109,681	36,900	110,979
Sub-T (off-road and herbicide portion in Trans Budget as of FY 10)	115,271	156,147	219,388	244,465	140,359
Police/Flagman Detail	87,763	229,163	330,635	197,392	127,227
Customer Requests	117,220	221,974	334,817	291,585	116,236
Trouble Maintenance	110,443	48,964	119,947	142,276	51,123
Other Veg Costs - Contractor	40,514	51,304	97,725	243,893	103,563
Other Veg Costs - All Other	166,092	174,431	210,546	258,250	111,103
OPEX - VM Total	**3,456,070**	**4,925,870**	**6,687,265**	**7,037,576**	**3,805,479**

Division Data Request 11-38

Request:

Please provide any reports issued in the last five years by rating agencies, such as Standard & Poor's, Moody's, Fitch or others, that evaluate and / or establish the debt or credit ratings for both National Grid and Narragansett Electric.

Response:

Credit rating agency reports issued in 2004 and 2005 for National Grid USA and Narragansett Electric are provided herewith as Attachments DIV-11-38-1 through 11-38-17. Please note that reports issued during 2006, 2007, 2008 and 2009 were provided in the response to COMM 1-10.

Prepared by or under the supervision of: Andrew E. Dinkel III

Division Data Request 11-39

Request:

Regarding NG-JP-4, please provide the underlying calculations and assumptions that produced this exhibit in Excel spreadsheet format will all formulae in tact.

Response:

Please see the accompanying excel file associated with Schedule NG-JP-4.

Prepared by or under the supervision of: John Pettigrew

New England Main Office & Special Purpose Consolidation

Cashflows (postive = saving/inflow) $m real prices	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Financial Year Ending March	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
52 Second Av - lease costs passed to sub tenant			0.5	2.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
52 Second Av - operating and capex costs avoided (H,L,P & Rates)			0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
52 Second Av - one off CTA (inc TI, removals)		(1.0)	(1.0)																		
Reservoir Woods - fit out (net of TI allowance)		(25.0)	(17.0)																		
Reservoir Woods - new annual lease / operating costs			(8.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)	(11.9)
Westborough - operating and capex costs avoided	1.0	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Westborough - net sales proceeds (cash)			22.0																		
Westborough - one off CTA (removals)		(1.0)	(1.0)																		
Northborough - fit out costs			(17.0)																		
Northborough - increased operating costs (comms, security)			(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)	(0.7)
Lincoln - operating and capex costs avoided		0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Lincoln - net sales proceeds (cash)				5.0																	
Weybosset - operating and capex costs avoided	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Weybosset - net sales proceeds (cash)			6.8																		
Cumberland - operating and capex costs avoided						0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cumberland - project space net costs avoided (Global ERP)		(1.0)	2.0	2.0	2.0																
Cumberland - net sales proceeds						4.0															
Property Tax savings		0.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Sub total - direct property cashflows	1.6	(21.6)	(7.2)	3.6	0.6	3.1	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
Estimated cost savings in operating businesses, IS and Shared Services	0.0	0.0	1.6	3.3	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Total Cashflows	**1.6**	**(21.6)**	**(5.6)**	**6.9**	**7.1**	**9.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**	**5.6**

5 Year NPV	(5.2)
10 Year NPV	10.1
15 Year NPV	21.0
20 Year NPV	28.7

NPV Discount Rate at 7%

Saugus

Sell 2 existing, owned properties and consolidate into new, to be built bldg that NG will own (Analysis begins upon completion of new bldg in 2 years)

Current Locations	Office	Ops	Spc. Purp	USF	GSF	Office	Physical	Total	Vehicles
Malden E	17,261	19,368	13,224	54,492	65,192	63	104	167	129
Malden G	-	-	-	52,000	52,000	36	123	159	-
Totals	17,261	19,368	13,224	106,492	117,192	99	227	326	129

OPEX COSTS	Facility O&M	Utilities	Lease	Facilities Dept Subtotal	Property Taxes	Total Direct Costs	Net Book Value per Integration File	Est .Sales Proceeds	Proceeds Value Used
Malden E	$ 0.35	$ 0.00	$ 0.00	$ 0.35	$ 0.12	$ 0.47	$ 8.32	$ 5.40	BOV
Malden G	$ 0.13	$ 0.07	$ 0.00	$ 0.19	$ 0.36	$ 0.55	$ 2.73	$ 4.80	BOV
Totals	$ 0.47	$ 0.07	$ 0.00	$ 0.54	$ 0.48	$ 1.02	$ 11.05		

Cash Flows (Escalations at 2.5% per Year)	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Malden Gas Facility Cost Savings		$ 0.20	$ 0.21	$ 0.21	$ 0.22	$ 0.22	$ 0.23	$ 0.24	$ 0.24	$ 0.25	$ 0.25
Malden Gas Property Tax Savings			$ 0.39	$ 0.40	$ 0.41	$ 0.42	$ 0.43	$ 0.44	$ 0.45	$ 0.46	$ 0.47
Malden Gas Sales Proceeds (less 10% COS)		$ 4.32									
Malden Gas Capital Savings ($3/SF)		$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16	$ 0.16
Malden Gas CTA - Relocation ($8/SF)	$ 0.42										
Malden Gas - CTA Environmental	$ 1.00										
Malden Electric Facility Cost Savings		$ 0.37	$ 0.37	$ 0.38	$ 0.39	$ 0.40	$ 0.41	$ 0.42	$ 0.43	$ 0.44	$ 0.46
Malden Electric Property Tax Savings			$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.16	$ 0.16
Malden Electric Sales Proceeds (less 10% COS)		$ 4.86									
Malden Electric Capital Savings ($3/SF)		$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20	$ 0.20
Malden Electric CTA - Relocation ($8/SF)	$ 0.52										
Malden Electric - CTA Environmental	$ 0.20										
Saugus Cost of New Building + D Site (Woburn)	$ 9.46										
Saugus Annual Opex for New Building + D Site		$ 0.26	$ 0.27	$ 0.27	$ 0.28	$ 0.29	$ 0.29	$ 0.30	$ 0.31	$ 0.32	$ 0.32
Tax Savings / (Costs) at 35%	$ 0.75	$ 0.11	$ 0.29	$ 0.30	$ 0.31	$ 0.31	$ 0.32	$ 0.33	$ 0.34	$ 0.35	$ 0.36
Net Cash Flow After-Tax (Cost)/Savings)	$ 10.85	$ 9.73	$ 0.89	$ 0.91	$ 0.92	$ 0.93	$ 0.95	$ 0.96	$ 0.98	$ 0.99	$ 1.01
Cumulative Cash Flows	$ 10.85	$ 1.12	$ 0.22	$ 0.68	$ 1.60	$ 2.54	$ 3.49	$ 4.45	$ 5.43	$ 6.43	$ 7.44
NPV (5%) Benefit: Years 0 - 5	**$ 1.50**										
NPV (5%) Benefit: Years 0 - 10	**$ 4.82**										
NPV (5%) Benefit: Years 0 - 15	**$ 7.64**										
NPV (5%) Benefit: Years 0 - 20	**$ 10.04**										
NPV (5%) Benefit: Years 0 - 25	**$ 12.10**										
Annual Opex and Capital Savings for Vacated Sites	$ 0.00	$ 0.92	$ 1.45	$ 1.48	$ 1.51	$ 1.54	$ 1.56	$ 1.60	$ 1.63	$ 1.66	$ 1.69

New Building Costs

Proposed SF for New Bldg (Est. Headcount)		Employees	SF/Employee	SF Required
	Office - Ops	99	150	14,850
	Physical	227	25	5,675
	Whse / Storage			10,000
	Office - Non Ops	0	150	0
				30,525
New Building Cost		SF	Cost/SF	Total Cost
Cost to Build New Building(s)/Renovations	Incl. land & sitewor	30,525	$300	$9,157,500
D Site Costs (Woburn)		2,000	$150	$300,000
Operating Costs for New Building (incl O&M, taxes & utilities)		$8.00	/SF	$244,200

Assumptions:

* Analysis assumes a 1/1/11 start date for Year 1
* Analysis assumes 2 years for new bldg or renovation of existing consolidation site, then 1 year to sell vacated bldgs.
* Discount rate of 5% used for NPV calculations
*Cash flows escalated by 2.5% assuming 2008 values
*Reinvestment rate of 9.5% used based on input from NG Finance
* Sales proceeds determined by most confident estimate based on either 50% of NBV, recent appraisal or updated BOV values
*Opex and NBV are based on values in Integration File

*Environmental costs per EHS

Beverly

Dispose of Current Beverly G & E Facilities - relocate to new Beverly Combined Center

Current Locations	Office	Ops	Spc. Purp	USF	GSF	Office	Physical	Total	Vehicles
Beverly E	4,743	15,336	11,593	32,215	37,501	11	53	64	70
Beverly G	-	-	-	9,800	9,800	8	78	86	-
Totals	4,743	15,336	11,593	42,015	47,301	19	131	150	70

Opex	Facility O&M	Utilities	Lease	Facilities Dept Subtotal	Property Taxes	Total Direct Costs	Net Book Value per Integration File	Est. Sales Proceeds	Proceeds Value Used		
	COST										
Beverly E	$ 0.09	$ 0.00	$ 0.00	$ 0.11	$ 0.05	$ 0.16	$ 0.63	$ 4.82	BOV		
Beverly G	$ 0.02	$ 0.00	$ 0.00	$ 0.04	$ 0.21	$ 0.26	$ 1.29		**SALES VALUE INCLUDED IN ABOVE SITE		
Totals	$ 0.12	$ 0.00	$ 0.00	$ 0.15	$ 0.26	$ 0.42	$ 1.92				
Cash Flows (Escalations at 2.5% per Year)	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Beverly E Facility Cost Savings			$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
Beverly E Property Tax Savings			$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.07	$ 0.07
Beverly E Sales Proceeds (less 10% COS)		$ 4.34									
Beverly E Capital Savings ($3/SF)		$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
Beverly E CTA - Relocation ($8/SF)	$ 0.30										
Beverly E - CTA Environmental	$ 1.00										
Beverly G Facility Cost Savings		$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.06	$ 0.06
Beverly G Property Tax Savings			$ 0.23	$ 0.23	$ 0.24	$ 0.25	$ 0.25	$ 0.26	$ 0.26	$ 0.27	$ 0.28
Beverly G Sales Proceeds (less 10% COS)		$ 0.00									
Beverly G Capital Savings ($3/SF)		$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03
Beverly G CTA - Relocation ($8/SF)	$ 0.08										
Beverly G - CTA Environmental	$ 1.00										
Beverly - Cost for new building	$ 4.84										
Beverly Annual Opex for New Building		$ 0.13	$ 0.13	$ 0.14	$ 0.14	$ 0.14	$ 0.15	$ 0.15	$ 0.15	$ 0.16	$ 0.16
Tax Savings / (Costs) at 35%	$ 0.83	$ 0.03	$ 0.07	$ 0.07	$ 0.07	$ 0.07	$ 0.08	$ 0.08	$ 0.08	$ 0.08	$ 0.08
Net Cash Flow After-Tax (Cost)/Savings)	$ 6.38	$ 4.43	$ 0.27	$ 0.27	$ 0.28	$ 0.28	$ 0.28	$ 0.29	$ 0.29	$ 0.29	$ 0.30
Cumulative Cash Flow	$ 6.38	$ 1.96	$ 1.69	$ 1.41	$ 1.14	$ 0.86	$ 0.57	$ 0.28	$ 0.01	$ 0.30	$ 0.60
NPV (5%) Benefit: Years 0 - 5	**$ 1.24**										
NPV (5%) Benefit: Years 0 - 10	**$ 0.25**										
NPV (5%) Benefit: Years 0 - 15	**$ 0.57**										
NPV (5%) Benefit: Years 0 - 20	**$ 1.27**										
NPV (5%) Benefit: Years 0 - 25	**$ 1.85**										
Annual Opex and Capital Savings for Vacated Sites	$0	$112,503	$167,898	$169,283	$170,703	$172,158	$173,649	$175,178	$176,745	$178,351	$179,997

New Building Costs				
Proposed SF for New Bldg (Est. Headcount)		Employees	SF/Employee	SF Required
	Office - Ops	19	150	2,850
	Physical	131	25	3,275
	Whse / Storage			10,000
	Office - Non Ops	0	150	0
				16,125
New Building Cost		SF	Cost/SF	Total Cost
Cost to Build New Building(s)/Renovations	Incl. land & sitewor	16,125	$300	$ 4,837,500
Operating Costs for New Building (incl O&M, taxes & utilities)		$8.00	/SF	$ 129,000

Assumptions:

* Analysis assumes a 1/1/11 start date for Year 1
* Analysis assumes 2 years for new bldg or renovation of existing consolidation site, then 1 year to sell vacated bldgs.
* Discount rate of 5% used for NPV calculations
*Cash flows escalated by 2.5% assuming 2008 values

* Sales proceeds determined by most confident estimate based on either 50% of NBV, recent appraisal or updated BOV values
*Opex and NBV are based on values in Integration File
*Environmental costs per Rick Schmitz of EHS
*Beverly Gas and Electric are assumed to be sold as one property

Division Data Request 11-40

Request:

For each year from 1994 through 2008, please provide the annual peak load for the Narragansett Electric system.

Response:

Please see the table below for the annual peak load for the Narragansett Electric system.

Year	Annual Peak (kW)
1994	1,369,700
1995	1,384,500
1996	1,261,200
1997	1,393,500
1998	1,418,400
1999	1,516,226
2000	1,464,733
2001	1,659,015
2002	1,692,106
2003	1,646,078
2004	1,618,320
2005	1,778,047
2006	1,937,906
2007	1,767,967
2008	1,780,168

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

Division Data Request 12-2

Request:

Please provide copies of the manual(s) and policy statement(s) describing how to allocate costs under the agreements provided in response to question #1.

Response:

Please see Attachment 1 to DIV 12-2 for an overview of the costs allocation process for National Grid USA Service Company.

Please see Attachment 2 to DIV 12-2 for the information relating to bill pool allocations.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-18

Request:

What was the 2008 amount of dollars in account 910 that was not related to energy efficiency costs?

Response:

As indicated in the response to DIV 12-19, 2008 energy efficiency costs were charged to Accounts 908 and 909. Therefore, the 2008 amount of $2,379,969 charged to Account 910, as reported on the Ferc Form 1, is not related to energy efficiency costs.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 12-19

Request:

Please specify amounts of Energy Efficiency Expenses recorded in the 2008 FERC Form 1, by account.

Response:

As shown in Workpaper NG-RLO-3, Energy Efficiency Expenses for 2008 were recorded to the FERCs in the amounts indicated below:

Regulatory Acct (FERC)	Amount
908000	$14,139,846
909000	146,367
Total	$14,286,213

Prepared by or under the supervision of: Robert L. O’Brien

Division Data Request 13-1

Request:

At line 22, page 36 of Mr. Gorman's testimony, he states that the Company is billed for transmission service by the ISO-NE on a basis similar to the way it is billed by NEP.

a. Please describe explicitly the basis for the ISO-NE billing of the Company for transmission service.

b. Please provide a breakdown of the total cost for transmission service in 2008 between NEP, ISO-NE and other transmission providers. Please identify separately any other providers that were responsible for at least 5 percent of annual transmission billings.

Response:

a. All transmission rates paid by The Narragansett Electric Company are set pursuant to FERC-approved rate filings made in accordance with FERC regulations under Section 205 of the Federal Power Act and Sections 35.12 and 35.13 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 35.12 and 35.13). The relevant tariff by which the Narragansett Electric Company is charged for transmission service is the ISO New England Transmission, Markets and Services Tariff No. 3 ("ISO Tariff").

Part II of the ISO Tariff contains the rates, terms and condition for regional transmission services over the backbone transmission or "PTF" for all of New England. These rates are known as Regional Network Service rates ("RNS rates"). The RNS rates use a FERC-approved rate-setting methodology that is commonly used for establishing FERC-jurisdictional transmission rates, known as a formula rate. Under a formula rate, the Commission approves the method by which a transmission revenue requirement is determined and the manner by which the rate itself is designed. Once a rate formula is approved, transmission providers are permitted to periodically update the cost data in the formula to reflect current costs for the relevant time period over which the rate is being charged. So long as there are no deviations from the formula method approved by FERC, no further Commission approval is needed to implement these cost updates. The Commission-approved annual revenue requirement formula for RNS rates is contained in Attachment F of the ISO Tariff. Under the Attachment F formula, New England Power Company's (NEP) PTF related revenue requirement is added to similar PTF revenue requirements of all PTF Transmission Owners in New England to establish a single RNS rate that is then charged to all PTF Monthly Network Load across New England. Monthly Network Load as defined under Section II.21.2 of the ISO Tariff is the Regional Network Customer's (in this case Narragansett Electric Company's) hourly load coincident with the coincident aggregate load

Division Data Request 13-1 (cont.)

of all Network Customers serviced in each Local Network in the hour in which the coincident load is at its maximum for the month. The Local Network for Narragansett Electric Company is defined to be any load directly connected to National Grid's transmission system.

Similarly, Schedule 21 and Schedule 21-NEP of the ISO Tariff establish the rates, terms and conditions for NEP's Local Network Service rates ("LNS rates") that are charged to all transmission load customers interconnected directly to NEP's transmission facilities for local or "non-PTF" transmission services. The basis for the billing of LNS rates, similar to RNS rates, is the hourly load coincident with the coincident aggregate load of all Local Network Customers serviced across National Grid's Local Network. The Schedule 21-NEP LNS rates are calculated and designed in a manner similar to the rate setting methodology for RNS rates in that they are set using a FERC-approved monthly revenue requirement and rate design formula. These are contained in Attachments RR, and Schedule OCC of Schedule 21–NEP.

Section IV.A of the ISO Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions. The rates and charges for each service during a calendar year are based on the allocated portion of that year's budgeted total expenses as adjusted by true-ups from the prior year. ISO-NE files a forecast of each schedules revenue requirement each year with Commission establishing the rates, terms and conditions for the ISO Administrative Costs for that year.

b. In 2008, the total transmission service costs to The Narragansett Electric Company were $83,643,266. Transmission costs from NEP and ISO-NE totaled $24,959,408 and $58,094,882, respectively. There are no other providers responsible for at least 5 percent of transmission costs during 2008.

Division Data Request 13-2

Request:

Line 15 in Schedule NG-HSG-7 is titled “Difference from Revenue at Current Rates.” Should that heading read, “Difference from Allocated Total Transmission Revenues,” referring back to line 8?

Response:

Yes, a better line description for Line 15 would be “Difference from Allocated 2010 Total Transmission Revenue”, which would compare Line 14 with Line 8.

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

<u>Division Data Request 13-3</u>

<u>Request</u>:

Regarding the "Allocated Share of 2008 Net Charge-Offs for Standard Offer & Last Resort Service Accounts by Rate Class" on line (3), Section 5, page 7 of Schedule NG-RLO-6, are the amounts for each class directly assigned? That is, is the $5,145,349 for A-16 the actual amount that customers in Class A-16 failed to pay? Of, is the $5,145,349 a portion of the jurisdictional total of $7,861,885 that was allocated to the A-16 class? If the latter, please provide the allocation vector used to allocate these costs.

<u>Response</u>:

The "Allocated Share of 2008 Net Charge-Offs for Standard Offer & Last Resort Service Accounts by Rate Class" on line (3), Section 5, page 7 of Schedule NG-RLO-6 is the estimated allocation the total of 2008 net charge offs of $12,412,851 on line (3) of Section 1, page 7. The Company used the following methodology for allocating the Company's net charge-offs between delivery service and commodity service.

The Company's net charge-offs, as derived from its general ledger, and the Company's system that tracks charge-offs, only do so at the highest level (e.g., billing components are aggregated and there is no differentiation between service classification (rate class) and energy supply (Standard Offer and Last Resort versus Competitive Supply)). Therefore, the Company established a method to determine a proportionate share of net charge-offs that would fairly reflect only Standard Offer and Last Resort net charge-offs. Since all gross charge-offs must be initiated through the Company's billing system and the majority of recoveries also flow through the billing system, the Company believes that this information is a reasonable source for performing such an allocation.

The Company uses this information as a means to allocate net charge-offs to rate classes and then to amounts associated with Standard Offer and Last Resort billings. First, the Company allocates the total net charge-offs to rate classes. The reason for this allocation is that charge-off levels differ among rate classes, and the percentage of a customer's total bill that is attributable to what he/she is billed for Standard Offer and Last Resort Service is also dependent upon which rate class the customer receives delivery service. Therefore, to reach as accurate an end result of the analysis as possible, which is a fair representation of the level of Standard Offer and Last Resort charge-offs, it is necessary to perform the analysis by rate class. Based upon gross charge-off and recovery reports generated from the Company's billing system, the Company derives allocators by rate class. These allocators are then applied to the total net charge-offs to arrive at allocated total net charge-offs by rate class. This allocation is presented in <u>Section 1: Allocation of 2008 Net Charge-Offs to Rate Classes</u>.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 13-3 (cont.)

Next, the Company needs to arrive at a way to estimate the proportionate share of total net charge-offs for Standard Offer and Last Resort Service customers that related only to Standard Offer and Last Resort Service amounts. Using the gross charge-off and recovery reports discussed above, the Company was able to accumulate the gross charge-off and recovery data associated with customers classified on Standard Offer and Last Resort Service. The Company was then able to calculate, based on the data contained in its billing system, the percentage of net charge-offs attributable to Standard Offer and Last Resort Service accounts. This percentage is calculated in Section 2. Standard Offer % Last Resort Service Accounts as a Percentage of All Accounts. By determining this percentage, the Company could then estimate an allocable share of total net charge-offs attributable to amounts billed for Standard Offer and Last Resort Service for those Standard Offer and Last Resort Service accounts. This estimate is calculated in Section 3. Allocation of 2008 Net Charge-Offs to Standard Offer & Last Resort Service Accounts.

From the net charge-offs for Standard Offer and Last Resort Service customers accumulated from the Company's billing system, the Company then derives an estimate of the level of Standard Offer and Last Resort Service billings reflected in these net charge-offs. To accomplish this, the Company determines each rate class's total average rate for Standard Offer and Last Resort Service customers on a monthly basis. By determining how much the Standard Offer and Last Resort Service rate represents of the total average rate for each rate class, the Company derives an allocator used to determine a reasonable level of Standard Offer and Last Resort Service billings, measured as a percentage, that were likely included in the net Standard Offer and Last Resort Service charge-off amount. The result of this analysis represents an estimate of what was charged off related to Standard Offer and Last Resort Service billings as reflected in the Company's billing system. This estimate is converted to a percentage of total Standard Offer and Last Resort Service charge-offs attributable to Standard Offer and Last Resort Service billings. This percentage is calculated in Section 4. Commodity Billing Charge-Offs as a Percentage of Standard Offer and Last Resort Service Accounts Charged Off. Finally, this percentage is applied to the estimate of the allocated share of Standard Offer and Last Resort Service charge-offs to arrive at an estimate of the allocable share of Standard Offer and Last Resort Service charge-offs attributable to Standard Offer and Last Resort Service billings. This estimate is calculated in Section 5. Allocation of Estimated Commodity Charge-Offs to Commodity Billings.

The methodology described above is the same methodology currently used by Narragansett Electric Company's affiliates in Massachusetts and New Hampshire.

Please note that the footnote relating to Section 3, Line 2 Page 7 of Schedule NG-RLO-6 should read "Section 2, Line (5)", not "Section 2, Line (3)".

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 13-4

Request:

Please reconcile the $4.301 million of "Uncollectibles Accounts-Delivery" on line 80, page 40 of Schedule NG-HSG-1, with the $4,550,966 "Net Charge-Off Alloc to Delivery" for 2008, in column (e), page 1 of Schedule NG-RLW-1, and with the $5,020,477 of delivery service uncollectible costs cited in paragraph (1)(c) of the proposed "Distribution Adjustment Provision."

a. If not reconcilable, please explain why and also please provide the backup data and analyses for the $4.301 million of "Uncollectibles Accounts-Delivery" that was allocated to classes on line 80, page 40 of Schedule NG-HSG-1.

Response:

The $4.301 million of "Uncollectibles Accounts-Delivery" on line 80, page 40 of Schedule NG-HSG-1 is the Rate Year expense based on a two-year average charge off rate applied to delivery revenue derived from presently-effective rates, as described by Company witness Mr. Robert O'Brien.

The $4,550,966 "Net Charge-Off Alloc to Delivery" for 2008, in column (e), page 1 of Schedule NG-RLW-1 is Total Net Charge-Offs by the Company in 2008 less the amount applicable to Commodity Service.

The $5,020,477 cited in paragraph (1) (c) of the proposed Distribution Adjustment Provision" can be found on page 1, line 16, column (h) of Schedule NG-RLO-2 and it represents the Rate Year expense of delivery-related uncollectible accounts adjusted for the revenue increase requested in this case.

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 13-5

Request:

Regarding the "Reactivation Charge" of $25 referred to by Mr. Walter at lines 2-3 on page 8 of his testimony, please provide all data and analyses that demonstrate that it will cost the Company $25 to turn on a light fixture that has been temporarily turned off.

Response:

The proposal is to modify the present S-14 Disconnection charge of $25 applied to each light which is temporarily turned-off to a Reactivation Charge of $25 for only those lights requested to be restored to active service prior to the minimum turn-off period. The disconnection charge has been present for many years within the S-14 tariff. The change to the tariff moves the reference of the charge from an imbedded statement within a body of text to an individual line item for billing clarity. The supporting analysis for $25 charge when it was established is unavailable.

Prepared by or under the supervision of: John Walter

Division Data Request 13-6

Request:

Please provide all workpapers in Excel format with all formulas intact that underlie the comparisons of typical bills at present and proposed rates in Schedule NG-HSG-9.

Response:

Please see “Schedule NG-HGS-9.xls” for the comparisons of typical bills at present and proposed rates in Excel format.

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

Narragansett Electric Company Exhibit 6
d/b/a National Grid
Docket No. R.I.P.U.C. ____
Schedule NG-HSG-9

Purpose: This File Compares Present vs. Sample Rates.

**** To Update this File go to the Input Section ****

There are Four Sections for the Input Section
(1) Heading Input Section
(2) Footnotes Input Section
(3) Adjustments Input Section (includes the Input for the most Current Adjustment Factors and other delivery charges)
(4) Distribution, Transmission, Transition and Standard Offer Input Section

Input Section

Heading Input Section:

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates

Present Rates
Proposed Rates

Footnotes Input Section:

Note (1): Includes Transmission Adjustment Factor of $0.01064/kWh

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00215/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

Adjustments Input Section:

		Present	Effective Date	Proposed	Effective Date
C&LM Adjustment	C&LM Adjustment	$0.00350	1-Jan-09	$0.00350	1-Jul-09
S.O. Adj.	S.O. Adj.	$0.00000	1-Oct-01	$0.00000	1-Oct-01
Transmission Adj	Transmission Adj - A16 & A60	0.01064	1-Jan-07		1-Jul-09
	Transmission Adj - C06, C08 & R12				1-Jul-09
	Transmission Adj - G2				1-Jul-09
	Transmission Adj - B32/G32 (& B62/G62)				1-Jul-09
Renewable Energy Standard Charge	Renewable Energy Standard Charge	0.00093	15-Jul-08	0.00093	15-Jul-08
Standard Offer Charge	Standard Offer Charge	$0.09200	15-Jul-08	$0.09200	15-Jul-08
Commodity Administrative Cost Adj. - Small	Commodity Administrative Cost Adj. - Small	$0.00000		$0.00215	1-Jul-09
Commodity Administrative Cost Adj. - Large	Commodity Administrative Cost Adj. - Large	$0.00000		$0.00078	1-Jul-09

Distribution, Transmission, Transition and Standard Offer Input Section:

				Present		Proposed	
A-16	A-16	Customer Charge	Customer Charge	$2.75	28-Oct-04	$5.50	28-Oct-04
		Transmission Charge (1)	Transmission Charge	$0.01500	1-Jan-07	$0.01630	1-Jan-07
		Distribution Energy Charge	Distribution Energy Charge	$0.03376	1-Jan-07	$0.04199	1-Jan-09
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09508	1-Jan-07
		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06
A-60	A-60	Customer Charge	Customer Charge	$0.00	28-Oct-04	$0.00	28-Oct-04
		Transmission Charge (1)	Transmission Charge	$0.01402	1-Jan-07	$0.01630	1-Jan-07
		Initial Block Energy Charge (1st 450 kWh)	Distribution Energy Charge	$0.00382	1-Jan-07	$0.02650	1-Jan-07
		Second Block Energy Charge (next 750 kWh)	n/a	$0.03055	28-Oct-04	n/a	28-Oct-04
		Tail Block Energy Charge	n/a	$0.02548	28-Oct-04	n/a	28-Oct-04
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09508	1-Jan-07

		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Credit for 1st 750 kWh	Credit for 1st 750 kWh	$0.00000	1-Jan-07	$0.00000	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06
C-06	C-06	Unmetered Charge	Unmetered Charge	$1.83	28-Oct-04	$5.00	28-Oct-04
		Customer Charge	Customer Charge	$6.00	28-Oct-04	$10.00	28-Oct-04
		Transmission Charge (1)	Transmission Charge	$0.01600	1-Jan-07	$0.01640	1-Jan-07
		Distribution Energy Charge	Distribution Energy Charge	$0.03624	1-Jan-07	$0.04183	1-Jan-09
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09508	1-Jan-07
		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06
G-02	G-02	Customer Charge	Customer Charge	$103.41	28-Oct-04	$125.00	28-Oct-04
		Transmission Demand Charge-xcs 10 kW	Transmission Demand Charge	$1.40	1-Jan-07	$2.29	1-Jan-07
		Transmission Charge	Transmission Charge	$0.01064	1-Jan-07	$0.00725	1-Jul-09
		Distribution Demand Charge-xcs 10 kW	Distribution Demand Charge-xcs 10 kW	$3.22	1-Jan-06	$4.50	1-Jan-06
		Distribution Energy Charge	Distribution Energy Charge	$0.00777	28-Oct-04	$0.00917	28-Oct-04
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09371	1-Jan-07
		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06
G-32	G-32	Customer Charge	Customer Charge	$236.43	28-Oct-04	$980.00	28-Oct-04
		Transmission Demand Charge	Transmission Demand Charge	$1.27	1-Jan-07	$2.28	1-Jan-07
		Transmission Charge	Transmission Charge	$0.01064	1-Jan-07	$0.00621	1-Jul-09
		Distribution Demand Charge	Distribution Demand Charge-xcs 200 kW	$1.99	1-Jan-07	$2.50	1-Jan-09
		Distribution Energy Charge	Distribution Energy Charge	$0.00889	1-Jan-07	$0.00840	1-Jan-09
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09371	1-Jan-07
		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06
G-62	G-62	Customer Charge	Customer Charge	$17,118.72	28-Oct-04	$980.00	28-Oct-04
		Transmission Demand Charge	Transmission Demand Charge	$1.39	1-Jan-07	$2.28	1-Jan-07
		Transmission Charge	Transmission Charge	$0.01064	1-Jan-07	$0.00621	1-Jul-09
		Distribution Demand Charge	Distribution Demand Charge-xcs 200 kW	$2.22	1-Jan-07	$2.50	1-Jan-09
		Distribution Energy Charge	Distribution Energy Charge	$0.00000	1-Jan-07	$0.00840	1-Jan-09
		Standard Offer Charge (2)	Standard Offer Charge (3)	$0.09293	1-Jan-07	$0.09371	1-Jan-07
		Transition Energy Charge	Transition Energy Charge	$0.00235	1-Jan-07	$0.00235	1-Jan-07
		Customer Credit	Customer Credit	$0.00000	1-Jan-06	$0.00000	1-Jan-06

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

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
120	$21.31	$11.62	$9.69	$25.64	$11.89	$13.75	$4.33	20.3%	20.3%
240	$39.75	$23.23	$16.52	$45.53	$23.77	$21.76	$5.78	14.5%	14.5%
500	$79.71	$48.40	$31.31	$88.66	$49.52	$39.14	$8.95	11.2%	11.2%
700	$110.44	$67.76	$42.68	$121.83	$69.33	$52.50	$11.39	10.3%	10.3%
950	$148.87	$91.96	$56.91	$163.29	$94.09	$69.20	$14.42	9.7%	9.7%
1,000	$156.55	$96.80	$59.75	$171.58	$99.04	$72.54	$15.03	9.6%	9.6%

Present Rates:	A-16		Proposed Rates:	A-16	
Customer Charge		$2.75	Customer Charge		$5.50
Transmission Charge (1)	kWh x	$0.01500	Transmission Charge	kWh x	$0.01630
Distribution Energy Charge	kWh x	$0.03376	Distribution Energy Charge	kWh x	$0.04199
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09508

Note (1): Includes Transmission Adjustment Factor of $0.01064/kWh
Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00215/kWh

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
100	$12.15	$9.68	$2.47	$14.97	$9.90	$5.07	$2.82	23.2%
200	$24.30	$19.36	$4.94	$29.95	$19.81	$10.14	$5.65	23.3%
300	$36.44	$29.04	$7.40	$44.91	$29.71	$15.20	$8.47	23.2%
500	$62.13	$48.40	$13.73	$74.86	$49.52	$25.34	$12.73	20.5%
750	$99.46	$72.60	$26.86	$112.29	$74.28	$38.01	$12.83	12.9%
1250	$173.86	$121.00	$52.86	$187.15	$123.80	$63.35	$13.29	7.6%

Present Rates:	A-60			Proposed Rates:	A-60	
Customer Charge			$0.00	Customer Charge		$0.00
Transmission Charge (1)	kWh x		$0.01402	Transmission Charge	kWh x	$0.01630
Initial Block Energy Charge (1st 450 kWh)	kWh x		$0.00382	Distribution Energy Charge	kWh x	$0.02650
Second Block Energy Charge (next 750 kWh)	kWh x		$0.03055			
Tail Block Energy Charge	kWh x		$0.02548			
Transition Energy Charge	kWh x		$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x		$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax			4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x		$0.09293	Standard Offer Charge (3)	kWh x	$0.09508

Note (1): Includes Transmission Adjustment Factor of $0.01064/kWh
Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00215/kWh

*Includes 1.306¢ per kWh credit approved by Commission in Docket No. 4011 for effect January 1, 2009 through December 31, 2009

Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on A-60 Rate Customers
Excludes Initial Block Low Income Credit

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
100	$13.51	$9.68	$3.83	$14.97	$9.90	$5.07	$1.46	10.8%
200	$27.02	$19.36	$7.66	$29.95	$19.81	$10.14	$2.93	10.8%
300	$40.52	$29.04	$11.48	$44.91	$29.71	$15.20	$4.39	10.8%
500	$68.25	$48.40	$19.85	$74.86	$49.52	$25.34	$6.61	9.7%
750	$105.58	$72.60	$32.98	$112.29	$74.28	$38.01	$6.71	6.4%
1250	$179.98	$121.00	$58.98	$187.15	$123.80	$63.35	$7.17	4.0%

Present Rates:	A-60		Proposed Rates:	A-60	
Customer Charge		$0.00	Customer Charge		$0.00
Transmission Charge (1)	kWh x	$0.01402	Transmission Charge	kWh x	$0.01630
Initial Block Energy Charge (1st 450 kWh)*	kWh x	$0.01688	Distribution Energy Charge	kWh x	$0.02650
Second Block Energy Charge (next 750 kWh)	kWh x	$0.03055			
Tail Block Energy Charge	kWh x	$0.02548			
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09508

Note (1): Includes Transmission Adjustment Factor of $0.01064/kWh
Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00215/kWh

*Does not include 1.306¢ per kWh credit approved by Commission in Docket No. 4011 for effect January 1, 2009 through December 31, 2009

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

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Custs
250	$45.58	$24.20	$21.38	$51.86	$24.76	$27.10	$6.28	13.8%	13.8%
500	$84.91	$48.40	$36.51	$93.31	$49.52	$43.79	$8.40	9.9%	9.9%
1,000	$163.56	$96.80	$66.76	$176.21	$99.04	$77.17	$12.65	7.7%	7.7%
1,500	$242.22	$145.20	$97.02	$259.10	$148.56	$110.54	$16.88	7.0%	7.0%
2,000	$320.87	$193.60	$127.27	$342.00	$198.08	$143.92	$21.13	6.6%	6.6%

Present Rates:	C-06			Proposed Rates:	C-06		
Customer Charge			$6.00	Customer Charge			$10.00
Transmission Charge (1)		kWh x	$0.01600	Transmission Charge		kWh x	$0.01640
Distribution Energy Charge		kWh x	$0.03624	Distribution Energy Charge		kWh x	$0.04183
Transition Energy Charge		kWh x	$0.00235	Transition Energy Charge		kWh x	$0.00235
C&LM Adjustment		kWh x	$0.00350	C&LM Adjustment		kWh x	$0.00350
Gross Earnings Tax			4.00%	Gross Earnings Tax			4.00%
Standard Offer Charge (2)		kWh x	$0.09293	Standard Offer Charge (3)		kWh x	$0.09508

Note (1): Includes Transmission Adjustment Factor of $0.01064/kWh
Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00215/kWh

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$644.14	$387.21	$256.93	$708.04	$390.46	$317.58	$63.90	9.9%
50	10,000	$1,520.95	$968.02	$552.93	$1,645.11	$976.15	$668.96	$124.16	8.2%
100	20,000	$2,982.30	$1,936.04	$1,046.26	$3,206.87	$1,952.29	$1,254.58	$224.57	7.5%
150	30,000	$4,443.65	$2,904.06	$1,539.59	$4,768.65	$2,928.44	$1,840.21	$325.00	7.3%

<u>Present Rates:</u> G-02		
Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293

<u>Proposed Rates:</u> G-02		
Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Charge	kWh x	$0.00725
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00917
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$888.28	$580.81	$307.47	$949.67	$585.69	$363.98	$61.39	6.9%
50	15,000	$2,131.31	$1,452.03	$679.28	$2,249.17	$1,464.22	$784.95	$117.86	5.5%
100	30,000	$4,203.03	$2,904.06	$1,298.97	$4,415.00	$2,928.44	$1,486.56	$211.97	5.0%
150	45,000	$6,274.75	$4,356.09	$1,918.66	$6,580.84	$4,392.66	$2,188.18	$306.09	4.9%

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

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293

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

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Charge	kWh x	$0.00725
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00917
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,132.43	$774.42	$358.01	$1,191.30	$780.92	$410.38	$58.87	5.2%
50	20,000	$2,741.68	$1,936.04	$805.64	$2,853.23	$1,952.29	$900.94	$111.55	4.1%
100	40,000	$5,423.76	$3,872.08	$1,551.68	$5,623.12	$3,904.58	$1,718.54	$199.36	3.7%
150	60,000	$8,105.85	$5,808.13	$2,297.72	$8,393.03	$5,856.88	$2,536.15	$287.18	3.5%

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

Customer Charge		$103.41
Transmission Demand Charge-xcs 10 kW	kW x	$1.40
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge-xcs 10 kW	kW x	$3.22
Distribution Energy Charge	kWh x	$0.00777
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293

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

Customer Charge		$125.00
Transmission Demand Charge	kW x	$2.29
Transmission Charge	kWh x	$0.00725
Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00917
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,376.57	$968.02	$408.55	$1,432.92	$976.15	$456.77	$56.35	4.1%
50	25,000	$3,352.04	$2,420.05	$931.99	$3,457.29	$2,440.36	$1,016.93	$105.25	3.1%
100	50,000	$6,644.49	$4,840.10	$1,804.39	$6,831.25	$4,880.73	$1,950.52	$186.76	2.8%
150	75,000	$9,936.94	$7,260.16	$2,676.78	$10,205.20	$7,321.09	$2,884.11	$268.26	2.7%

Present Rates:	G-02		Proposed Rates:	G-02	
Customer Charge		$103.41	Customer Charge		$125.00
Transmission Demand Charge-xcs 10 kW	kW x	$1.40	Transmission Demand Charge	kW x	$2.29
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00725
Distribution Demand Charge-xcs 10 kW	kW x	$3.22	Distribution Demand Charge-xcs 10 kW	kW x	$4.50
Distribution Energy Charge	kWh x	$0.00777	Distribution Energy Charge	kWh x	$0.00917
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4.00%	Gross Earnings Tax		4.00%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,855.03	$3,872.08	$1,982.95	$6,252.91	$3,904.58	$2,348.33	$397.88	6.8%
750	150,000	$21,279.09	$14,520.31	$6,758.78	$22,073.44	$14,642.19	$7,431.25	$794.35	3.7%
1,000	200,000	$28,290.03	$19,360.42	$8,929.61	$29,264.59	$19,522.92	$9,741.67	$974.56	3.4%
1,500	300,000	$42,311.91	$29,040.63	$13,271.28	$43,646.88	$29,284.38	$14,362.50	$1,334.97	3.2%
2,500	500,000	$70,355.65	$48,401.04	$21,954.61	$72,411.46	$48,807.29	$23,604.17	$2,055.81	2.9%

Present Rates:	G-32		Proposed Rates:	G-32	
Customer Charge		$236.43	Customer Charge		$980.00
Transmission Demand Charge	kW x	$1.27	Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00621
Distribution Demand Charge	kW x	$1.99	Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00889	Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$8,319.83	$5,808.13	$2,511.70	$8,631.46	$5,856.88	$2,774.58	$311.63	3.7%
750	225,000	$30,522.06	$21,780.47	$8,741.59	$30,992.97	$21,963.28	$9,029.69	$470.91	1.5%
1,000	300,000	$40,613.99	$29,040.63	$11,573.36	$41,157.30	$29,284.38	$11,872.92	$543.31	1.3%
1,500	450,000	$60,797.85	$43,560.94	$17,236.91	$61,485.94	$43,926.56	$17,559.38	$688.09	1.1%
2,500	750,000	$101,165.55	$72,601.56	$28,563.99	$102,143.23	$73,210.94	$28,932.29	$977.68	1.0%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge	kW x	$1.99
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293

Proposed Rates: G-32

Customer Charge		$980.00
Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.00621
Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$10,784.62	$7,744.17	$3,040.45	$11,010.00	$7,809.17	$3,200.83	$225.38	2.1%
750	300,000	$39,765.04	$29,040.63	$10,724.41	$39,912.51	$29,284.38	$10,628.13	$147.47	0.4%
1,000	400,000	$52,937.94	$38,720.83	$14,217.11	$53,050.00	$39,045.83	$14,004.17	$112.06	0.2%
1,500	600,000	$79,283.78	$58,081.25	$21,202.53	$79,325.00	$58,568.75	$20,756.25	$41.22	0.1%
2,500	1,000,000	$131,975.44	$96,802.08	$35,173.36	$131,875.00	$97,614.58	$34,260.42	-$100.44	-0.1%

<u>Present Rates:</u> G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge	kW x	$1.99
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293

<u>Proposed Rates:</u> G-32

Customer Charge		$980.00
Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.00621
Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$13,249.41	$9,680.21	$3,569.20	$13,388.54	$9,761.46	$3,627.08	$139.13	1.1%
750	375,000	$49,008.00	$36,300.78	$12,707.22	$48,832.03	$36,605.47	$12,226.56	-$175.97	-0.4%
1,000	500,000	$65,261.90	$48,401.04	$16,860.86	$64,942.71	$48,807.29	$16,135.42	-$319.19	-0.5%
1,500	750,000	$97,769.72	$72,601.56	$25,168.16	$97,164.07	$73,210.94	$23,953.13	-$605.65	-0.6%
2,500	1,250,000	$162,785.34	$121,002.60	$41,782.74	$161,606.77	$122,018.23	$39,588.54	-$1,178.57	-0.7%

Present Rates: G-32

Customer Charge		$236.43
Transmission Demand Charge	kW x	$1.27
Transmission Charge	kWh x	$0.01064
Distribution Demand Charge	kW x	$1.99
Distribution Energy Charge	kWh x	$0.00889
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293

Proposed Rates: G-32

Customer Charge		$980.00
Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.00621
Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%
Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 200

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	600,000	$97,500.75	$58,081.25	$39,419.50	$86,793.75	$58,568.75	$28,225.00	-$10,707.00	-11.0%
5,000	1,000,000	$150,613.25	$96,802.08	$53,811.17	$144,322.91	$97,614.58	$46,708.33	-$6,290.34	-4.2%
7,500	1,500,000	$217,003.88	$145,203.13	$71,800.75	$216,234.38	$146,421.88	$69,812.50	-$769.50	-0.4%
10,000	2,000,000	$283,394.50	$193,604.17	$89,790.33	$288,145.84	$195,229.17	$92,916.67	$4,751.34	1.7%
20,000	4,000,000	$548,957.00	$387,208.33	$161,748.67	$575,791.66	$390,458.33	$185,333.33	$26,834.66	4.9%

Present Rates:	G-62		Proposed Rates:	G-32	
Customer Charge		$17,118.72	Customer Charge		$980.00
Transmission Demand Charge	kW x	$1.39	Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00621
Distribution Demand Charge	kW x	$2.22	Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00000	Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 300

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	900,000	$131,694.51	$87,121.88	$44,572.63	$122,471.88	$87,853.13	$34,618.75	-$9,222.63	-7.0%
5,000	1,500,000	$207,602.84	$145,203.13	$62,399.71	$203,786.46	$146,421.88	$57,364.58	-$3,816.38	-1.8%
7,500	2,250,000	$302,488.25	$217,804.69	$84,683.56	$305,429.69	$219,632.81	$85,796.88	$2,941.44	1.0%
10,000	3,000,000	$397,373.67	$290,406.25	$106,967.42	$407,072.92	$292,843.75	$114,229.17	$9,699.25	2.4%
20,000	6,000,000	$776,915.33	$580,812.50	$196,102.83	$813,645.83	$585,687.50	$227,958.33	$36,730.50	4.7%

Present Rates:	G-62		Proposed Rates:	G-32	
Customer Charge		$17,118.72	Customer Charge		$980.00
Transmission Demand Charge	kW x	$1.39	Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00621
Distribution Demand Charge	kW x	$2.22	Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00000	Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

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

Hours Use: 400

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,200,000	$165,888.25	$116,162.50	$49,725.75	$158,150.00	$117,137.50	$41,012.50	-$7,738.25	-4.7%
5,000	2,000,000	$264,592.42	$193,604.17	$70,988.25	$263,250.00	$195,229.17	$68,020.83	-$1,342.42	-0.5%
7,500	3,000,000	$387,972.63	$290,406.25	$97,566.38	$394,625.00	$292,843.75	$101,781.25	$6,652.37	1.7%
10,000	4,000,000	$511,352.83	$387,208.33	$124,144.50	$526,000.00	$390,458.33	$135,541.67	$14,647.17	2.9%
20,000	8,000,000	$1,004,873.67	$774,416.67	$230,457.00	$1,051,500.00	$780,916.67	$270,583.33	$46,626.33	4.6%

Present Rates:	G-62		Proposed Rates:	G-32	
Customer Charge		$17,118.72	Customer Charge		$980.00
Transmission Demand Charge	kW x	$1.39	Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00621
Distribution Demand Charge	kW x	$2.22	Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00000	Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

Narragansett Electric Company
d/b/a National Grid
Docket No. R.I.P.U.C. ____
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Calculation of Monthly Typical Bill
Comparison of Present and Proposed Rates
Impact on G-62 Rate Customers

Hours Use: 500

Monthly Power kW	kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total
3,000	1,500,000	$200,082.01	$145,203.13	$54,878.88	$193,828.13	$146,421.88	$47,406.25	-$6,253.88	-3.1%
5,000	2,500,000	$321,582.00	$242,005.21	$79,576.79	$322,713.54	$244,036.46	$78,677.08	$1,131.54	0.4%
7,500	3,750,000	$473,457.00	$363,007.81	$110,449.19	$483,820.32	$366,054.69	$117,765.63	$10,363.32	2.2%
10,000	5,000,000	$625,332.00	$484,010.42	$141,321.58	$644,927.09	$488,072.92	$156,854.17	$19,595.09	3.1%
20,000	10,000,000	$1,232,832.00	$968,020.83	$264,811.17	$1,289,354.16	$976,145.83	$313,208.33	$56,522.16	4.6%

Present Rates:	G-62		Proposed Rates:	G-32	
Customer Charge		$17,118.72	Customer Charge		$980.00
Transmission Demand Charge	kW x	$1.39	Transmission Demand Charge	kW x	$2.28
Transmission Charge	kWh x	$0.01064	Transmission Charge	kWh x	$0.00621
Distribution Demand Charge	kW x	$2.22	Distribution Demand Charge-xcs 200 kW	kW x	$2.50
Distribution Energy Charge	kWh x	$0.00000	Distribution Energy Charge	kWh x	$0.00840
Transition Energy Charge	kWh x	$0.00235	Transition Energy Charge	kWh x	$0.00235
C&LM Adjustment	kWh x	$0.00350	C&LM Adjustment	kWh x	$0.00350
Gross Earnings Tax		4%	Gross Earnings Tax		4%
Standard Offer Charge (2)	kWh x	$0.09293	Standard Offer Charge (3)	kWh x	$0.09371

Note (2): Includes Standard Offer of $0.092/kWh and Renewable Energy Standard Charge of $0.00093/kWh
Note (3): Includes Standard Offer of $0.092/kWh, Renewable Energy Standard Charge of $0.00093/kWh and proposed Commodity Cost Adjustment Factor of $0.00078/kWh

Division Data Request 13-8

Request:

Please provide all studies, calculations and supporting analyses and data for the proposed \$5.11/kW-month Backup Service demand charge in proposed Rate B-32.

a. Please also show the basis in cost for the increase in the Distribution Demand Charge for current B-62 customers of 130 percent from \$2.22/kW-month to \$5.11/kW-month.

Response:

The first step in designing Rates B-32, G-32, B-62 and G-62 ("C&I Large Demand") was to determine the proposed monthly customer charge of \$980.00, which includes billing costs and demand-related costs applicable to the first 200 kW of demand for these classes (see Schedule NG-HSG-6, page 5, line 8).

The next step was to determine the demand-based charges. The Company's proposed demand-based revenue is designed so the portion of C&I Large Demand revenue collected in the proposed customer charge plus the proposed demand-based charges is approximately the same as under current rates. The proposed demand-based charge for Supplemental Service (i.e., the customer receives electricity through the distribution system) was set at \$2.50 per kW of billing demand, representing an increase of approximately 26% for Rates B-32 and G-32 customers, and an increase of approximately 12% for Rates B-62 and G-62 customers. Different percentage increases reflect the fact that the costs to serve the customers in these classes are similar, therefore the proposed rates should be the same. Currently, Rates B-62 and G-62 customers pay higher demand-based charges and no energy charge, so a smaller percentage increase in the demand-based charge is necessary to arrive at \$2.50.

The proposed \$5.11/kW-month Backup Service demand charge for Rate B-32 was designed to be no higher than the current rate for such service. While this creates an increase of 130% in the Rate B-62 Backup Service demand charge, this item is only a small portion of a customer's monthly bill. It was considered important that Rate B-32 and Rate B-62 have the same rates and that the Rate B-32 Backup Service demand charge not increase.

Projected revenue from the proposed Rate B-62 Backup Service demand charge is \$477,000. Any increase to the proposed rate would result in only a slight decrease in the charges of all other Rate B-32 / G-32 / B-62 / G-62 customers.

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

Division Data Request 13-9

Request:

Please provide the following information for customers that took Backup service under Rate Schedule B-32 during the 12 months ending December 31, 2008:

a. Number of customers;
b. Total customer charge revenue;
c. Total billing demands; and
d. Total Distribution Demand Charge Revenue.

Response:

a. There were 3 customers during 9 months and 2 customers during 3 months.

b. The total customer charge revenue was $7,802.19

c. The total billing demands were 28,118.2 kW (9,010.4 for Back-up service and 19,107.8 for Supplemental Service)

d. Distribution Demand Charge Revenue was $84,250.16

Division Data Request 13-10

Request:

Please provide the following information for customers that took Backup service under Rate Schedule B-62 during the 12 months ending December 31, 2008:

a. Number of customers;
b. Total customer charge revenue;
c. Total billing demands; and
d. Total Distribution Demand Charge Revenue.

Response:

a. There were 2 customers

b. The total customer charge revenue was $410,849.28

c. The total billing demands were 388,938.4 kW (96,101.5 for Back-up service and 292,836.9 for Supplemental Service)

d. Distribution Demand Charge Revenue was $860,687.94

Division Data Request 15-1

Request:

As a follow-up to the response to Div. 2-9, please explain why linear miles of overhead conductors rather than circuit miles of overhead conductors are used to functionalize Account 364-Poles, Towers and Fixtures.

Response:

There is a causal relationship between the number of poles and the linear miles of conductors. As overhead conductors are extended, new poles, towers and fixtures are required to suspend the conductors. However, if conductors are extended to make a circuit, the conductors can be attached to existing poles, towers and fixtures.

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

Division Data Request 15-2

Request:

Referring to the Commission Order in Consolidated Docket Nos. 2290, 2290A and 2290B, provided in response to Div. No. 2-10, Narragansett Electric Company offered a Credit to Promote Manufacturing, which was estimated to result in a revenue shortfall of $1,957,000. This shortfall was borne by Narragansett's stockholders. Please describe any other economic development or bypass-pricing discounts that have been offered by the Company in the last 20 years to large customers where the resulting revenue shortfalls were allocated to other customers. In those instances, please indicate to which customer classes those revenue shortfalls were allocated.

Response:

During the last 20 years, the Company has offered economic development discounts. Please see Attachment 1 for Economic Development Rate tariffs offered by the Company. These economic development plans have been available to certain large industrial/manufacturing customers who continue to purchase certain pre-existing electricity requirements from the Company and locate new facilities or bring new business into Rhode Island.

As shown in Attachment 2 to this response, which is page 3 of Rate Design Attachment 2 to the October 11, 1995 Order on the Supplemental Settlement on Revenue Requirement and Rate Design in Docket 2290, revenue shortfalls related to economic development were allocated to all customer classes with the exception of rates E-01 and E-10.

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

R.I.P.U.C. No. 1013
Sheet 1
Cancelling R.I.P.U.C. No. 974

NARRAGANSETT ELECTRIC

ECONOMIC DEVELOPMENT RATE

TARIFF

Narragansett Electric is offering a special economic development rate to certain large industrial/manufacturing customers who continue to purchase certain pre-existing electricity requirements from the Company and locate new facilities or bring new business into Rhode Island.

1. Defined Terms

Special capitalized terms within this tariff are provided specific definitions in the glossary located in Section 12, at the end of this tariff.

2. Eligibility

Any industrial/manufacturing customer that meets the four eligibility requirements set forth below is eligible for this rate:

(a) G-30 or G-60 Customer

The customer must be taking service under the Company's G-30 or G-60 rate or meet the requirements for service under the Company's G-30 or G-60 rate after the addition of the Incremental Load.

(b) Size of Incremental Load

(1) As a result of the new business, the customer's kilowatthour usage must be 10% over its Base-Period Usage or at least 100 kW of billing demand over its Base-Period Billing Demand.

(2) For customers who are constructing new facilities in Rhode Island and have no pre-existing usage or demand, the customer's Base-Period Usage and Base-Period Billing Demand shall be zero.

(c) Jobs

(1) The customer must be increasing its current full-time work force in Rhode Island by 5% or more as a result of the expansion of its operations in Rhode Island. This requirement may be waived if the customer can substantially document to the Company's satisfaction that the new business is necessary to prevent loss of more than 5% of its current full-time work

force. However, the Company reserves complete discretion to determine whether the conditions for the waiver have been met.

(2) If the customer is a new business, it must be creating at least ten new full-time manufacturing jobs in Rhode Island.

(d) Energy Efficiency

(1) For new facilities, the customer must participate in the Company's Design 2000 conservation and load management program to the extent that program funds are available and apply to the customer's facilities.

(2) If the customer is expanding its business within existing facilities, the customer will participate in the Company's Conservation and Load Management Programs ("C&LM Programs") to the extent program funds are available and apply to the customer's facilities.

(3) At the Company's request, the customer must allow the Company to confirm that energy efficiency requirements have been met (by

inspection or other reasonable means requested by the Company).

(4) Participation in the Company's Design 2000 or other C&LM Programs may be waived by the Company to the extent that the customer demonstrates, to the Company's satisfaction, that the applicable facilities include or will include energy efficient electrical systems.

3. Special Contract

The customer must sign a special contract with the Company covering the entire term of this rate ("Special Contract"). In addition to the requirements provided in this tariff, the customer agrees to continue purchasing from the Company its pre-existing electricity requirements at all of its facilities within the service territory of the Company for the term of the contract. In addition, the customer agrees to purchase from the company its Incremental Load from the new or expanded facilities for the term of the contract.

4. Base Rate Discount

(a) This economic development rate provides a discount to base rates as specified in Section 4(b) below. The discount does not apply to charges associated with the Company's Fuel Adjustment, C&LM, OCA, UCCA, PPCA factors or any other adjustment factors which may go into effect during the term of the Special Contract.

(b) The amount of the discount shall be 20% during the first two years of the term selected by the customer, 16% during the third year, and 8% during the fourth year of the term. No discounts will be provided after 2000.

5. Availability of this tariff, during 1996 is limited to a maximum of 20 megawatts of additional capacity. As the Company signs up customers under this tariff, the amount of capacity available for discounting shall be reduced by the number of megawatts (MW) from the Incremental Load being added. When the Available Capacity for 1996 is reduced to zero, the discount will no longer be available to additional customers.

Customers will be considered for service under this tariff on a first come, first served basis, based on the date the Special Contract is signed.

6. <u>Applicability to Incremental Load</u>

The discount shall apply <u>only</u> to the customer's Incremental Load. The discount shall not apply to the Base Period Usage or Base Period Billing Demand. The Company will establish the conditions for measuring and metering the Incremental Load on a case by case basis and incorporate those conditions into the Special Contract in each case.

7. <u>Effective Date</u>

Eligible customers may take service under this rate for usage on and after February 1, 1996.

8. <u>Expiration of Rate</u>

A Special Contract must be executed by December 31, 1996, for a customer to be eligible for this rate. After December 31, 1996, this rate will be closed to new customers.

9. <u>Existing Tariffs Shall Apply</u>

The customer will take service under the G-30 or G-60 rate, subject to the additional terms and conditions provided under this tariff. All of the Company's general Terms and Conditions shall apply, as they may be amended from time to time.

10. <u>Relocation Within Rhode Island</u>

If a customer relocates its business from one location in the Company's service territory to another, the Company may determine the Incremental Load from the customer's usage and billing demand that existed prior to the relocation.

11. <u>Construction Contributions</u>

To the extent that the addition of the Incremental Load to the Company's system requires an investment by the Company in new distribution or related facilities, the Company's construction advance policy shall apply.

12. <u>Glossary of Terms</u>

For purposes of this tariff, the following terms shall have the meanings given below:

(a) "Base Period Usage" shall be the customer's average kWh usage over the most recent 12 month period or such other amount of kWh determined by the Company to be an appropriate representative level from which to measure incremental usage, given the circumstances of the customer.

(b) "Base-Period Billing Demand" shall be the customer's average billing demand over the most recent 12-month period or such other demand determined by the Company to be an appropriate representative level from which to measure incremental billing demand, given the circumstances of the customer.

(c) "Incremental Load" shall be the amount of kWh usage and kW of billing demand over and above the customer's Base-Period Usage and Base-Period Billing Demand.

Effective Date: February 1, 1996

NARRAGANSETT ELECTRIC

ECONOMIC DEVELOPMENT RATE

TARIFF

Narragansett Electric is offering a special economic development rate to certain large industrial/manufacturing customers who continue to purchase certain pre-existing electricity requirements from the Company and locate new facilities or bring new business into Rhode Island.

1. Defined Terms

Special capitalized terms within this tariff are provided specific definitions in the glossary located in Section 12, at the end of this tariff.

2. Eligibility

Any industrial/manufacturing customer that meets the four eligibility requirements set forth below is eligible for this rate:

(a) G-30 Customer

The customer must be taking service under the Company's G-30 rate or meet the requirements for service under the Company's G-30 rate after the addition of the Incremental Load.

(b) <u>Size of Incremental Load</u>

(1) As a result of the new business, the customer's kilowatthour usage must be 10% over its Base-Period Usage or at least 100 kW of billing demand over its Base-Period Billing Demand.

(2) For customers who are constructing new facilities in Rhode Island and have no pre-existing usage or demand, the customer's Base-Period Usage and Base-Period Billing Demand shall be zero.

(c) <u>Jobs</u>

(1) The customer must be increasing its current full-time work force in Rhode Island by 5% or more as a result of the expansion of its operations in Rhode Island. This requirement may be waived if the customer can substantially document to the Company's satisfaction that the new business is necessary to prevent loss of more than 5% of

its current full-time work force. However, the Company reserves complete discretion to determine whether the conditions for the waiver have been met.

(2) If the customer is a new business, it must be creating at least ten new full-time manufacturing jobs in Rhode Island.

(d) Energy Efficiency

(1) For new facilities, the customer must participate in the Company's Design 2000 conservation and load management program to the extent that program funds are available and apply to the customer's facilities.

(2) If the customer is expanding its business within existing facilities, the customer will participate in the Company's Conservation and Load Management Programs ("C&LM Programs") to the extent program funds are available and apply to the customer's facilities.

(3) At the Company's request, the customer must allow the Company to confirm that energy efficiency requirements have been met (by

inspection or other reasonable means requested by the Company).

(4) Participation in the Company's Design 2000 or other C&LM Programs may be waived by the Company to the extent that the customer demonstrates, to the Company's satisfaction, that the applicable facilities include or will include energy efficient electrical systems.

3. Special Contract

The customer must sign a special contract with the Company covering the entire term of this rate ("Special Contract"). In addition to the requirements provided in this tariff, the customer agrees to continue purchasing from the Company its pre-existing electricity requirements at all of its facilities within the service territory of the Company for the term of the contract. In addition, the customer agrees to purchase from the company its Incremental Load from the new or expanded facilities for the term of the contract.

4. Base Rate Discount

(a) This economic development rate provides a discount to base rates as specified in Section 5 below. The discount does not apply to charges associated with the Company's Fuel Adjustment, C&LM, OCA, UCCA, PPCA factors or any other adjustment factors which may go into effect during the term of the Special Contract.

(b) The amount of the discount shall be 20% during the first two years of the term selected by the customer, 16% during the third year, and 8% during the fourth year of the term. No discounts will be provided after 1999.

5. Availability

Availability of this tariff during 1995 is limited to a maximum of 20 megawatts of additional capacity. As the Company signs up customers under this tariff, the amount of capacity available for discounting shall be reduced by the number of megawatts (MW) from the Incremental Load being added. When Available Capacity for 1995 is reduced to zero, the discount will no longer be available to additional customers.

Customers will be considered for service under this tariff on a first come, first served basis, based on the date the Special Contract is signed.

6. <u>Applicability to Incremental Load</u>

The discount shall apply <u>only</u> to the customer's Incremental Load. The discount shall not apply to the Base Period Usage or Base Period Billing Demand. The Company will establish the conditions for measuring and metering the Incremental Load on a case by case basis and incorporate those conditions into the Special Contract in each case.

7. <u>Effective Date</u>

Eligible customers may take service under this rate for usage on and after March 13, 1995.

8. <u>Expiration of Rate</u>

A Special Contract must be executed by December 31, 1995, for a customer to be eligible for this rate. After December 31, 1995, this rate will be closed to new customers.

9. Existing Tariffs Shall Apply

The customer will take service under the G-30 rate, subject to the additional terms and conditions provided under this tariff. All of the Company's general Terms and Conditions shall apply, as they may be amended from time to time.

10. Relocation Within Rhode Island

If a customer relocates its business from one location in the Company's service territory to another, the Company may determine the Incremental Load from the customer's usage and billing demand that existed prior to the relocation.

11. Construction Contributions

To the extent that the addition of the Incremental Load to the Company's system requires an investment by the Company in new distribution or related facilities, the Company's construction advance policy shall apply.

12. Glossary of Terms

For purposes of this tariff, the following terms shall have the meanings given below:

(a) "Base Period Usage" shall be the customer's average kWh usage over the most recent 12 month period or such other amount of kWh determined by the Company to be an appropriate representative level from which to measure incremental usage, given the circumstances of the customer.

(b) "Base-Period Billing Demand" shall be the customer's average billing demand over the most recent 12-month period or such other demand determined by the Company to be an appropriate representative level from which to measure incremental billing demand, given the circumstances of the customer.

(c) "Incremental Load" shall be the amount of kWh usage and kW of billing demand over and above the customer's Base-Period Usage and Base-Period Billing Demand.

Effective Date: March 13, 1995

R.P.U.C. No. 967
Sheet 1

Cancelling R.P.U.C. No. 962

NARRAGANSETT ELECTRIC

ECONOMIC DEVELOPMENT RATE

TARIFF

Narragansett Electric is offering a special economic development rate to certain large industrial/manufacturing customers who continue to purchase certain pre-existing electricity requirements from the Company and locate new facilities or bring new business into Rhode Island.

1. Defined Terms

Special capitalized terms within this tariff are provided specific definitions in the glossary located in Section 12, at the end of this tariff.

2. Eligibility

Any industrial/manufacturing customer that meets the four eligibility requirements set forth below is eligible for this rate:

(a) G-30 Customer

The customer must be taking service under the Company's G-30 rate or meet the requirements for service under the Company's G-30 rate after the addition of the Incremental Load.

(b) Size of Incremental Load

(1) As a result of the new business, the customer's kilowatthour usage must be 10% over its Base-Period Usage or at least 100 kW of billing demand over its Base-Period Billing Demand.

(2) For customers who are constructing new facilities in Rhode Island and have no pre-existing usage or demand, the customer's Base-Period Usage and Base-Period Billing Demand shall be zero.

(c) Jobs

(1) The customer must be increasing its current full-time work force in Rhode Island by 5% or more as a result of the expansion of its operations in Rhode Island. This requirement may be waived if the customer can substantially document to the Company's satisfaction that the new business is necessary to prevent loss of

more than 5% of its current full-time work force. However, the Company reserves complete discretion to determine whether the conditions for the waiver have been met.

(2) If the customer is a new business, it must be creating at least ten new full-time manufacturing jobs in Rhode Island.

(d) <u>Energy Efficiency</u>

(1) For new facilities, the customer must participate in the Company's Design 2000 conservation and load management program to the extent that program funds are available and apply to the customer's facilities.

(2) If the customer is expanding its business within existing facilities, the customer will participate in the Company's Conservation and Load Management Programs ("C&LM Programs") to the extent program funds are available and apply to the customer's facilities.

(3) At the Company's request, the customer must allow the Company to confirm that energy efficiency requirements have been met (by

inspection or other reasonable means requested by the Company).

(4) Participation in the Company's Design 2000 or other C&LM Programs may be waived by the Company to the extent that the customer demonstrates, to the Company's satisfaction, that the applicable facilities include or will include energy efficient electrical systems.

3. Special Contract

The customer must sign a special contract with the Company covering the entire term of this rate ("Special Contract"). In addition to the requirements provided in this tariff, the customer agrees to continue purchasing from the Company its pre-existing electricity requirements at all of its facilities within the service territory of the Company for the term of the contract. In addition, the customer agrees to purchase from the company its Incremental Load from the new or expanded facilities for the term of the contract.

4. Base Rate Discount

This economic development rate provides a discount to base rates as specified in Section 5 below. The discount does not apply to charges associated with the Company's Fuel Adjustment, C&LM, OCA, UCCA, PPCA factors or any other adjustment factors which may go into effect during the term of the Special Contract.

5. Four Year Block Discounts Available

(a) Under this tariff, the Company will provide a four year discount to customers, subject to the availability of capacity for each year for the period 1994 through 1998 (in accordance with the capacity amounts allocated for each year in subparagraph (b) below). As the Company signs up customers under this tariff, the amount of capacity available for discounting in each year shall be reduced by the number of megawatts (MW) from the Incremental Load being added under this tariff. When Available Capacity for a given year (as defined in subparagraph (b) below) is reduced to zero, the discount will no longer be available to additional customers for such year.

(b) For purposes of this tariff, the amount of megawatts(MW) of capacity available in each year ("Available Capacity") for discounted electricity shall be as follows:

1994 -- 33 MW

1995 -- 23 MW

1996 -- 13 MW

1997 -- 5 MW

1998 -- 5 MW

(c) To the extent that the Company's forecast of capacity for a given year changes, the Company reserves the right (but is not obligated) to amend subparagraph (b) above. However, any customer who already has executed a Special Contract under this tariff shall not be affected by any such amendment.

(d) Each customer participating under this tariff shall be limited to a four year discount. The customer may select the calendar year in which the discount shall begin, but may not begin later than January 1, 1995. However, if there no longer is any Available Capacity for any year(s) in the requested four year discount, the term of the discount shall be shortened to exclude such year(s). For example, if a customer requests a four year discount beginning in 1995, but there no longer is any Available Capacity in 1998 (as provided in subparagraph (b) above), the term of the discount would be limited to three years, ending at the end of 1997.

(e) The amount of the discount shall be 20% during the first two years of the term selected by the customer, 16% during the third year, and 8% during the fourth year of the term. No discounts will be provided after 1998.

(f) Customers will be considered for service under this tariff on a first come, first served basis, based on the date the Special Contract is signed.

6. Applicability to Incremental Load

The discount shall apply only to the customer's Incremental Load. The discount shall not apply to the Base Period Usage or Base Period Billing Demand. The Company will establish the conditions for measuring and metering the Incremental Load on a case by case basis and incorporate those conditions into the Special Contract in each case.

7. Effective Date

Eligible customers may take service under this rate for usage on and after April 26, 1994.

8. Expiration of Rate

A Special Contract must be executed by December 31, 1994, for a customer to be eligible for this rate. After December 31, 1994, this rate will be closed to new customers.

9. Existing Tariffs Shall Apply

The customer will take service under the G-30 rate, subject to the additional terms and conditions provided under this tariff. All of the Company's general Terms and Conditions shall apply, as they may be amended from time to time.

10. Relocation Within Rhode Island

If a customer relocates its business from one location in the Company's service territory to another, the Company may determine the Incremental Load from the customer's usage and billing demand that existed prior to the relocation.

11. Construction Contributions

To the extent that the addition of the Incremental Load to the Company's system requires an investment by the Company in new distribution or related facilities, the Company's construction advance policy shall apply.

12. Glossary of Terms

For purposes of this tariff, the following terms shall have the meanings given below:

(a) "Base Period Usage" shall be the customer's average kWh usage over the most recent 12 month period or such other amount of kWh determined by the Company to be an appropriate representative level from which to measure incremental usage, given the circumstances of the customer.

(b) "Base-Period Billing Demand" shall be the customer's average billing demand over the most recent 12-month period or such other demand determined by the Company to be an appropriate representative level from which to measure incremental billing demand, given the circumstances of the customer.

(c) "Incremental Load" shall be the amount of kWh usage and kW of billing demand over and above the customer's Base-Period Usage and Base-Period Billing Demand.

Effective Date: April 26, 1994

NARRAGANSETT ELECTRIC

ECONOMIC DEVELOPMENT RATE

TARIFF

Narragansett Electric is offering a special economic development rate to certain large industrial/manufacturing customers who continue to purchase certain pre-existing electricity requirements from the Company and locate new facilities or bring new business into Rhode Island.

1. Defined Terms

   Special capitalized terms within this tariff are provided specific definitions in the glossary located in Section 12, at the end of this tariff.

2. Eligibility

   Any industrial/manufacturing customer that meets the five eligibility requirements set forth below is eligible for this rate:

   (a) G-30 Customer

   The customer must be taking service under the Company's G-30 rate or meet the requirements for service under the Company's G-30 rate after the addition of the Incremental Load.

   (b) Size of Incremental Load

(1) As a result of the new business, the customer's kilowatthour usage must be 10% over its Base-Period Usage and at least 100 kW of billing demand over its Base-Period Billing Demand.

(2) For customers who are constructing new facilities in Rhode Island and have no pre-existing usage or demand, the customer's Base-Period Usage and Base-Period Billing Demand shall be zero.

(c) <u>Jobs</u>

(1) The customer must be increasing its current full-time work force in Rhode Island by 5% or more as a result of the expansion of its operations in Rhode Island. This requirement may be waived if the customer can substantially document to the Company's satisfaction that the new business is necessary to prevent loss of more than 5% of its current full-time work force. However, the Company reserves complete discretion to determine whether the conditions for the waiver have been met.

(2) If the customer is a new business, it must be creating at least ten new full-time manufacturing jobs in Rhode Island.

(d) Energy Efficiency

(1) For new facilities, the customer must participate in the Company's Design 2000 conservation and load management program to the extent that program funds are available and apply to the customer's facilities.

(2) If the customer is expanding its business within existing facilities, the customer will participate in the Company's Conservation and Load Management Programs ("C&LM Programs") to the extent program funds are available and apply to the customer's facilities.

(3) At the Company's request, the customer must allow the Company to confirm that energy efficiency requirements have been met (by inspection or other reasonable means requested by the Company).

(4) Participation in the Company's Design 2000 or other C&LM Programs may be waived by the Company to the extent that the customer demonstrates, to the Company's satisfaction, that the applicable facilities include or will include energy efficient electrical systems.

(e) <u>Other Incentives or Assistance</u>

The customer must be receiving at least one of the following benefits or incentives from the State or local government designed to assist or encourage the customer to expand its business or locate its facilities in Rhode Island:

(1) A tax treaty with the local city or town, which reduces property tax liability of the new or existing facilities by at least five percent or freezes the tax rate for at least two consecutive years;

(2) Receipt of State guaranteed financing, such as revenue bonds, covering at least $1 million or ten percent (whichever is greater) of the construction cost of the new expanded facilities; or

(3) Other significant incentives or assistance provided by the State, local government or Rhode Island State officials consisting of material benefits, as determined by the Company, being provided directly to the customer to assist the customer in expanding or locating its business in Rhode Island.

3. <u>Special Contract</u>

The customer must sign a special contract with the Company covering the entire term of this rate ("Special Contract"). In addition to the requirements provided in this tariff, the customer agrees to continue purchasing from the Company its pre-existing electricity requirements at the location of the new or expanded facilities for the term of the contract. In addition, the customer agrees to purchase from the company its Incremental Load from the new or expanded facilities for the term of the contract.

4. <u>Base Rate Discount</u>

This economic development rate provides a discount to base rates as specified in Section 5 below. The discount does <u>not</u> apply to charges associated with the Company's Fuel Adjustment, C&LM, OCA, UCCA, PPCA factors or any other adjustment factors which may go into effect during the term of the Special Contract.

5. <u>Four Year Block Discounts Available</u>

(a) Under this tariff, the Company will provide a four year discount to customers, subject to the availability of capacity for each year for the period 1992 through 1997 (in accordance with the capacity amounts allocated for each year in subparagraph (b) below). As the Company signs up customers under this tariff, the amount of capacity available for discounting in each year shall be reduced by the number of megawatts (MW) from the Incremental Load being added under this tariff. When Available Capacity for a given year (as defined in subparagraph (b) below) is reduced to zero, the discount will no longer be available to additional customers for such year.

(b) For purposes of this tariff, the amount of megawatts (MW) of capacity available in each year ("Available Capacity") for discounted electricity shall be as follows:

1992 -- 53 MW

1993 -- 43 MW

1994 -- 33 MW

1995 -- 23 MW

1996 -- 13 MW

1997 -- 5 MW

(c) To the extent that the Company's forecast of capacity for a given year changes, the Company reserves the right (but is not obligated) to amend subparagraph (b) above. However, any customer who already has executed a Special Contract under this tariff shall not be affected by any such amendment.

(d) Each customer participating under this tariff shall be limited to a four year discount. The customer may select the calendar year in which the discount shall begin, but may not begin later than 1994. However, if there no longer is any Available Capacity for any year(s) in the requested four year discount, the term of the discount shall be shortened to exclude such year(s). For example, if a customer requests a four year discount beginning in 1994, but there no longer is any Available Capacity in 1997 (as provided in subparagraph (b) above), the term of the discount would be limited to three years, ending at the end of 1996.

(e) The amount of the discount shall be 20% during the first two years of the term selected by the customer, 16% during the third year, and 8% during the fourth year of the term.

(f) Customers will be considered for service under this tariff on a first come, first served basis, based on the date the Special Contract is signed.

6. <u>Applicability to Incremental Load</u>

The discount shall apply <u>only</u> to the customer's Incremental Load. The discount shall not apply to the Base Period Usage or Base Period Billing Demand. The Company will establish the conditions for measuring and metering the Incremental Load on a case by case basis and incorporate those conditions into the Special Contract in each case.

7. <u>Effective Date</u>

Eligible customers may take service under this rate for usage on and after September 1, 1992.

8. <u>Expiration of Rate</u>

A Special Contract must be executed by August 31, 1994, for a customer to be eligible for this rate. After August 31, 1994, this rate will be closed to new customers.

9. <u>Existing Tariffs Shall Apply</u>

The customer will take service under the G-30 rate, subject to the additional terms and conditions provided under this tariff. All of the Company's general Terms and Conditions shall apply, as they may be amended from time to time.

10. <u>Relocation Within Rhode Island</u>

If a customer relocates its business from one location in the Company's service territory to another, the Company may determine the Incremental Load from the customer's usage and billing demand that existed prior to the relocation.

11. Construction Contributions

To the extent that the addition of the Incremental Load to the Company's system requires an investment by the Company in new distribution or related facilities, the Company's construction advance policy shall apply.

12. Glossary of Terms

For purposes of this tariff, the following terms shall have the meanings given below:

(a) "Base Period Usage" shall be the customer's average kWh usage over the most recent 12 month period or such other amount of kWh determined by the Company to be an appropriate representative level from which to measure incremental usage, given the circumstances of the customer.

(b) "Base-Period Billing Demand" shall be the customer's average billing demand over the most recent 12-month period or such other demand determined by the Company to be an appropriate representative level from which to measure incremental billing demand, given the circumstances of the customer.

(c) "Incremental Load" shall be the amount of kWh usage and kW of billing demand over and above the customer's Base-Period Usage and Base-Period Billing Demand.

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)

Division Data Request 15-4

Request:

Please provide a breakdown by individual customer class of the total Commodity Revenue of $700,112,298 shown on line (3) of Section 2 on page 15 of Schedule NG-RLO-6.

Response:

Please see table below for a breakdown of the total Commodity revenue of $700,112,298 by individual customer rate class.

Rate Class	**Small Customer Group**	**Rate Class**	**Large Customer Group**
A16	$296,732,420	B32	$272,369
A60	$20,064,183	B62	$4,415,823
C06	$54,657,325	G02	$131,238,082
C08	$171,036	G32	$151,225,255
E30	$158,149	G62	$37,500,767
E40	$305,582	X01	$197,797
R02	$312,678		
S10	$980,739		
S14	$732,005		
T06	$451,539		
T08	$696,549		
Total	**$375,262,205**		**$324,850,093**

Prepared by or under the supervision of: Robert L. O'Brien

Division Data Request 16-1

Request:

Re: page 4 of 15, lines 8-9, of the testimony of witness Fields. Please:

a. Provide the source document(s) from which the total job losses during 2008 were determined;

b. Identify the "high value" professional and business sectors to which the witness refers;

c. Quantify the job losses within the identified "*high value*" sectors in Rhode Island during 2008, if known by the Company.

d. Identify and provide the data upon which the witness relies to assess that the referenced "*high value*" sectors have been "*particularly hard hit*;" and

e. Identify the manner in which the Company's proposed economic development programs will address the referenced "*high value*" professional and business sectors.

Response:

a. The primary source document is a March 2009 news release from the Rhode Island Department of Labor and Training. The document is provided as Attachment DIV 16-1, and is also available at: http://www.dlt.state.ri.us/News_Releases/pdfs/NR_030309.pdf

b. The "high value professional and business services" sectors referenced include research and development, architectural, consulting, engineering and other services. The term "high value" was also used in the testimony to describe the manufacturing sector.

c. According to the Rhode Island Department of Labor and Training, from January 2008 to January 2009, Rhode Island jobs in the manufacturing sector declined by 4,100; for the Professional and Business Services sector, the decline was reported to be 3,400.

d. As indicated in the response to part 16-1(c) above, the "high value" professional and business services and manufacturing sectors lost a combined total of 7,500 jobs in Rhode Island from January 2008 to January 2009. Those two categories

Division Data Request 16-1

alone (out of the 15 components of non-farm employment) represented nearly 40 percent of the total State job losses during that period.

e. Some programs will target these industries directly, by restricting eligibility to companies in those industries. The programs will provide funding to help offset energy infrastructure costs or to otherwise encourage the business to invest and remain in Rhode Island. Other programs may support those industries indirectly by funding marketing and sales initiatives aimed at attracting and/or retaining customers in those industries, as well as businesses within the supply chain of the "high value" sectors, marketing initiatives aimed at attracting or retaining businesses in those industries). Other industry sectors may be targeted as well if they emerge as critical targets as a result of the information gathered during the company's proposed collaborative program development process.

Rhode Island Department of Labor and Training

MEDIA ADVISORY

MEDIA CONTACTS:

Laura Hart (401) 462-8090 lhart@dlt.ri.gov
Nicole Romeo (401) 462-8744 nromeo@dlt.ri.gov

Embargoed until
Tuesday, March 3, 2009

	Jan 09	Dec 08*	Jan 08*
RI Unemployment Rate	**10.3%**	9.4%	6.3%
US Unemployment Rate	**7.6%**	7.2%	4.9%
RI Job Count (*in thousands*)	**469.6**	471.2	488.6

*Revised

Highlights:

- The January RI jobless rate rose to 10.3 percent from a revised December rate of 9.4 percent.
- Last month, the number of unemployed RI residents increased 4,600 over the month to reach 57,800.

Unemployment Rate Climbs to 10.3 percent

The RI Department of Labor and Training announced today that the state's seasonally adjusted unemployment rate reached 10.3 percent, climbing nine-tenths of a percent over December's revised unemployment rate.

From December 2008 to January 2009, the U.S. unemployment rate rose four-tenths of a percent to reach 7.6 percent.

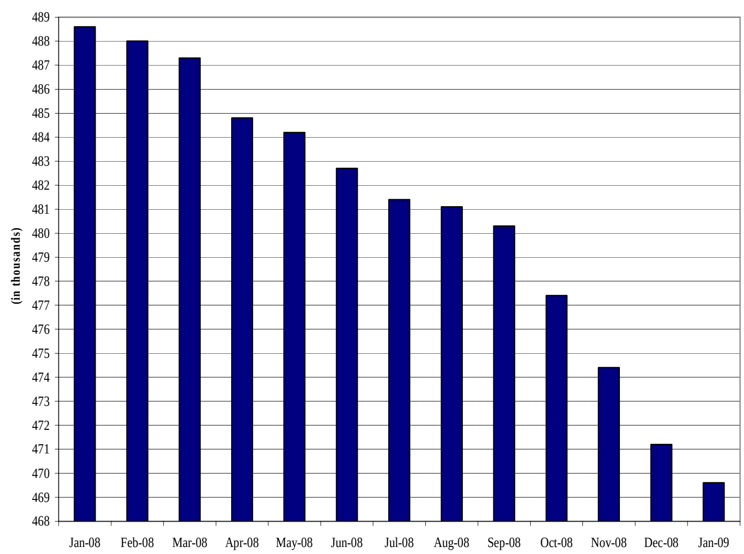
The monthly unemployment rate is calculated through an estimating process that compares the number of unemployed residents to the total labor force.

In January, the number of unemployed RI residents—those residents who classify themselves as available for and actively seeking employment—increased by 4,600 over the month to reach 57,800. From January 2008 to January 2009, the number of unemployed RI residents increased 22,000.

Due to numerous eligibility requirements, the number of unemployed RI residents differs from the number of RI unemployment insurance recipients. The average weekly claim load for RI unemployment insurance benefits in January was 35,850.

On a related note, the number of employed RI residents totaled 504,900 in January 2009, reflecting a decrease of 7,200 from the previous month. Over the year, the number of employed RI residents fell 28,100 between January 2008 and January 2009.

Rhode Island Seasonally Adjusted Establishment Employment
January 2008 - January 2009



JOBS BASED IN RHODE ISLAND:
The January 2009 count of RI-based jobs totaled 469,600, a decline of 1,600 jobs from December's revised employment level of 471,200. January marks the twelfth straight month of job losses for Rhode Island, and the thirteen consecutive months of job declines for the US.

(Continued)

Rhode Island Department of Labor and Training

MEDIA ADVISORY

In January, Construction, Professional & Business Services, Educational Services and Wholesale Trade each experienced a loss of 300 jobs. Also in January, job losses were reported in Manufacturing and Health Care & Social Assistance, with each sector shedding 200 jobs. Elsewhere, over-the-month employment declines were noted in Financial Activities (-100), Arts, Entertainment & Recreation (-100), and Transportation & Utilities (-100).

Retail Trade, the only sector to add jobs in January, reported a gain of 300 employees. This increase may be attributed to the fact that holiday hiring fell well below traditional hiring, resulting in less retail layoffs. Overall, January employment in Retail Trade (47,100) was down 1,600 from pre-holiday hiring in October 2008 (48,700).

Employment in Information, Accommodation & Food Services, Other Services, Government and Natural Resources & Mining remained unchanged between December 2008 and January 2009.

From January 2008 to January 2009, RI jobs declined 19,000 (-3.9 %) due to job losses in nearly all economic sectors. The largest annual employment declines were reported in Manufacturing (-4,100), followed by Retail Trade (-3,600), Professional & Business Services (-3,400), Construction (-2,700), Government (-1,500) and Financial Activities (-1,200). Smaller losses were noted in Arts, Entertainment & Recreation (-700), Wholesale Trade (-600), Accommodation & Food Services (-600), Other Services (-500), Transportation & Utilities (-400) and Information (-300)

Health Care & Social Assistance and Educational Services reported employment increases over the year, with gains of 500 and 100 jobs, respectively.

MANUFACTURING: In January 2009, production workers in the Manufacturing sector earned $13.99 per hour. The average hourly production wage was down seven cents from December and up one cent from a year ago January. Manufacturing employees worked an average of 37.5 hours per week in January, down three-tenths of an hour over the month and down an hour and one-tenth since January 2008.

SEASONALLY-ADJUSTED NON-FARM EMPLOYMENT IN RHODE ISLAND
(in thousands)

				Net Change From	
	Jan-09	Dec-08	Jan-08	Dec-08	Jan-08
Total Nonfarm	**469.6**	**471.2**	**488.6**	**-1.6**	**-19.0**
Natural Resources & Mining	0.2	0.2	0.2	0.0	0.0
Construction	18.6	18.9	21.3	-0.3	-2.7
Manufacturing	45.6	45.8	49.7	-0.2	-4.1
Wholesale Trade	16.5	16.8	17.1	-0.3	-0.6
Retail Trade	47.1	46.8	50.7	0.3	-3.6
Transportation & Utilities	10.7	10.8	11.1	-0.1	-0.4
Information	10.3	10.3	10.6	0.0	-0.3
Financial Activities	32.7	32.8	33.9	-0.1	-1.2
Professional & Business Services	52.4	52.7	55.8	-0.3	-3.4
Educational Services	23.3	23.6	23.2	-0.3	0.1
Health Care & Social Assistance	76.7	76.9	76.2	-0.2	0.5
Arts, Entertainment & Recreation	7.8	7.9	8.5	-0.1	-0.7
Accommodation & Food Services	42.6	42.6	43.2	0.0	-0.6
Other Services	22.5	22.5	23.0	0.0	-0.5
Government	62.6	62.6	64.1	0.0	-1.5

REVISIONS: In February, all states performed their annual revision of monthly labor force and employment data. In Rhode Island, this process resulted in a 1,200 upward revision in average annual employment in 2008. The December 2007 to December 2008 job decline was revised from a loss of 22,000 jobs to a loss of 17,200 jobs.

Employment data is benchmarked to the payroll data that is submitted by all employers, and labor force data is revised to reflect new population control totals. As a result, unadjusted job numbers are revised for 2007 and 2008, while seasonally adjusted job numbers and all labor force data are revised for 2004 through 2008.

(Continued)

MEDIA ADVISORY

Rhode Island Department of Labor and Training

The unemployment figures are based largely on a survey of households in Rhode Island and measure the unemployment status of people who live in the state. Unemployment rates prior to 1976 are not recognized by the US Bureau of Labor Statistics as official since the methodology used at that time is not comparable to today's methods. The establishment employment figures are derived from a survey of businesses in Rhode Island and measure the number of jobs in the state. Rhode Island labor market information is available at www.dlt.ri.gov/lmi. The February labor force figures are scheduled to be released on Friday, March 20, 2009.

The RI Department of Labor and Training offers employment services, educational services and economic opportunity to both individuals and employers. DLT protects Rhode Island's workforce by enforcing labor laws, prevailing wage rates and workplace health and safety standards. The department also provides temporary income support to unemployed and temporarily disabled workers. For more information on the programs and services available to all Rhode Islanders, please call the RI Department of Labor and Training at (401) 462-8000 or visit the web site at www.dlt.ri.gov.

Equal Opportunity Employer
Auxiliary aids and services are available upon request to individuals with disabilities / TDD (401) 462-8006

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Division Data Request 16-2

Request:

Re: page 4 of 15, lines 17-18, of the testimony of witness Fields. Please:

a. Explain why the Company has not previously proposed economic development programs for Rhode Island.

Response:

a. Until the National Grid-Niagara Mohawk 2002 merger in upstate New York, the Company's New England territory did not have any recent direct experience with economic development programs. In recognition of the benefits these programs have generated in New York State, the Company decided to pursue Economic Development in all parts of its US service areas. This proceeding provided the best opportunity to approach economic development comprehensively. The Company has a similar proposal in its ongoing Massachusetts electric rate proceeding.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-3

Request:

Re: page 4 of 15, lines 20-21, of the testimony of witness Fields. Please provide the basis, and any supporting documents, for the assertion that "*Utilities are widely regarded as effective economic development partners*."

Response:

There appears to be little analyses but considerable anecdotal information on the value of utilities in economic development. Attachment DIV-16-3 is an article published by Platts, which is the highly regarded publication that principally covers the energy industry. It is called *"Partnering for Success" –Revitalized Economic Development Adds Value to the Bottom Line. January 2004.*

Additionally, it is evidenced that utilities are recognized as effective and appropriate economic development partners by the large number of utilities who provide these services. There are currently some 65 investor-owned utilities that participate in the Utility Economic Development Association, covering a large portion of the U.S. and parts of Canada.

Prepared by or under the supervision of: Carmen Fields

January 2004
IND-8

Partnering for Success
Revitalized Economic Development Adds Value to the Bottom Line

The E SOURCE Industrial Service

CONTENTS

For More Information

We invite you to contact us for more information or to get answers to your questions: Kenneth Black, tel 720-548-5742, e-mail kenneth_black@esource.platts.com; Matthew Joyce, tel 720-548-5676, e-mail matthew_joyce@esource.platts.com.

About the Authors

Cindy Marzofka, president of Effective Communications, has worked in the electric and gas utility industry for nearly 20 years. She provides public relations, marketing, and strategic-planning services for gas and electric utilities and economic development organizations. Cindy has served as executive director of the Utility Economic Development Association since 2001 (www.utilityeda.com). Prior to launching her business in 1992, she worked in communications and economic development at Northern States Power Company–Wisconsin (now Xcel Energy) and Madison Gas and Electric Co. She received a BS from the University of Wisconsin–Oshkosh with a double major in journalism and radio-television-film studies.

Kenneth Black, managing director for Platts Research & Consulting, leads the *E SOURCE Large Commercial and Industrial Services* as well as the *E SOURCE Corporate Energy Managers' Consortium*. He has worked in the electric and gas utility industry for over 20 years, and has extensive experience in marketing, market research, business development, and energy services. He has developed and launched many new products and services for utilities and energy service companies. Before joining Platts, Ken was a founding partner of Public Energy Services LLC, where he helped utilities develop and manage energy services businesses. He has also worked for PECO Energy (now Exelon) and Entergy. Ken has a BA in biology and an MBA in marketing from Temple University.

Matthew Joyce, senior research associate with the E SOURCE Strategy & Marketing Group at Platts Research & Consulting, explores topics that affect energy-provider strategies and marketing initiatives. He has written numerous E source reports, including "Energy Managers Devise Post-Enron Strategies," "Restoring Customer Trust," "Corporate Energy Managers Speak Their Minds," "Preventing the Next Electricity Crisis," and "Playing to Win: Sport Marketing for ESPs." Before joining Platts, Matthew worked as a freelance journalist and editor. His assignments took him from Europe to Southeast Asia and Central America. His work has appeared in 16 books and in prominent U.S. magazines and newspapers. Matthew holds a BA in writing from the University of California.

Editorial services: Sarah Thompson
Production services: Hillary Wittner, Brent Zeinert

Partnering for Success

Revitalized Economic Development Adds Value to the Bottom Line

Cindy Marzofka, Kenneth Black, and Matthew Joyce

EXECUTIVE SUMMARY

A growing number of utilities are breaking down the traditional barriers between economic developers, key account managers, marketers, and business developers in an effort to encourage internal collaboration and stronger alliances with external partners. These partnerships are generating greater results than individuals, departments, or companies can achieve on their own.

To better position their service territories to compete for new investments, utilities are partnering with community organizations, realtors, and other businesses to promote their regions using a variety of tools ranging from Web sites and databases to strategic alliances and limited partnerships. To retain existing business and encourage local growth, utilities are helping their customers reduce waste, cut energy costs, increase efficiency and productivity, and tap into new technologies. They are also optimizing existing infrastructure by identifying local sites with available or underutilized utility capacity, and routing the information to external partners who direct growth to target areas. Finally, they are building strong relationships with key decision-makers in the business and political arenas, knowing that those associations will help them to clear the regulatory and legislative steps required to initiate and execute their economic development projects.

Successful economic development results in a healthy local economy that helps local businesses, improves the community's tax base, and increases utility sales and revenue. Consequently, key account managers, business developers, and marketers should be asking how they can help their customers to grow, sell more of their products/services, improve their product quality, and, of course, lower their costs to be more competitive.

Introduction

"We've created 1,350 jobs, occupied about 440,000 square feet of space, and added an estimated $500,000 in utility revenue each year," says Tim Comerford, manager of area development for Public Service Electric and Gas (PSE&G) in New Jersey.[1] He is describing SiteFinders LLC, a licensed New Jersey real estate firm formed by the utility to formalize strategic alliances and subsidize its economic development services. In its first two years of operation, SiteFinders has referred more than 200 prospects to member Realtors. The company has closed 14 deals and nearly 80 prospects remain active.

PSE&G's SiteFinders program is an example of a new breed of utility economic development efforts that stress partnerships, cooperation, and mutual benefits. Traditionally, economic developers, marketers, key account managers, strategists, and business and community developers have worked in separate silos. But now a growing number of utilities are breaking down barriers to encourage more internal collaboration and forge stronger bonds with external partners. The increased synergies are producing greater results than individual people, departments, or companies can achieve on their own.

Such efforts are helping utilities counter the lingering aftereffects of the California energy crisis, the Enron debacle, the fallout from deregulation that didn't happen or was not successful, the wholesale market meltdown, utility bankruptcies, and a string of dismal results from diversification that have pounded the industry like a bad hangover. And it could not come at a better time, given the nation's slow growth in electricity demand, a 2.4 million drop in manufacturing jobs over the last two years, and an all-time high in the national unemployment rate as of June 2003. All these economic ills have combined with a renewed emphasis on core customers to thrust utility economic development programs to center stage.

Utilities have a vested interest in sustaining a healthy economy, because their investments in communities are substantial. Fortunately, they are uniquely positioned to develop, coordinate, and advance initiatives designed to stimulate economic growth that will benefit local businesses and community residents, as well as the utilities themselves.

Many gas utilities, like Nicor, know that it's important to be "at the table" as a partner when a prospect is siting a facility, but it's hard to justify independent business-attraction efforts.[2] Natural gas supply and price are no longer major site-location factors—most large commercial and industrial customers have been buying gas on the open market for about 10 years, and today's gas price fluctuations affect everyone across the country. As a result, many gas utilities combine economic development with community or government relations to maximize the political benefits.

Utility economic development programs strive toward four primary goals: optimizing infrastructure, attracting new business to increase revenues, retaining and growing load through existing customers, and developing community relationships. All four of these objectives are better served when the many hands of the utility—people, departments, and partners—work together in concert. We've examined economic development efforts across the country and will be presenting best-in-class examples of this new holistic and collaborative approach to economic development, as well as discussing how account managers, strategists, and business and community developers can work with their economic development counterparts to achieve unified results.

Optimizing Infrastructure

Utilities are feeling the pressure to cut capital costs in an era of limited resources and a renewed focus on maximizing shareholder returns. A growing number of utilities are using economic development initiatives to strategically encourage growth where the utility has available and underutilized capacity. This is an effective way to optimize assets, whether an area is rebounding from a plant closing or favoring "smart growth" infill projects over urban sprawl. Even the new focus on homeland security has resulted in optimizing infrastructure and creating new business opportunities (see sidebar). Such activities help both companies and communities, have one of the highest return margins of any project, and add directly to the utility's bottom line.

Homeland Security Creates Opportunities

In the post-9/11 era, some financial companies and data centers are exploring sites to decentralize operations. Although a few utility economic developers report more information requests from these firms, not many companies have taken action in the soft economy. Some prospects want new locations that they can drive to in a day, in case airports shut down again in the future. Many businesses are asking more questions about dual feeds and other backup protection for their energy supply.

The National Office of Job Corps in Washington, D.C., is one firm that acted on its accountant's suggestion to create a backup data operation. RS Information Systems, a private contractor for the Job Corps, located the backup facility in Limestone, Maine, in a location where the necessary telecommunications infrastructure was already in place. The new location created about 20 jobs last year, and added 30 more in 2003.[3]

Some utilities support these efforts to capitalize on emerging security-related business opportunities. MidAmerican Energy teamed up with the Quad City Development Group to market the 1.5 million square feet of space that was available next to the Rock Island Arsenal in Illinois. Heightened security around the national defense supplier may help attract other firms to its 950-acre island in the Mississippi River. The Quad City Development Group created a subsidiary to manage the real estate details, with funding support from MidAmerican Energy. The utility's main thrust is marketing the space to defense-oriented businesses and other target firms that may benefit from the added security the site offers.[4]

As the national economy gains steam or leases expire, or both, more businesses may be motivated to decentralize operations or take other steps to address security issues.

Removing Barriers

Have utility infrastructure costs been a major impediment to your redevelopment projects? PSE&G recently advanced a smart-growth pilot program that proposes to remove the financial burden for utility upgrades and expansions in targeted areas from individual developers and customers.

PSE&G has proposed to test its Targeted Revitalization Incentive Program (TRIP) in six communities and six redevelopment areas in New Jersey. TRIP, which requires regulatory approval, would give PSE&G, developers, and customers an incentive to improve facilities in the targeted areas.[5]

Incentives are necessary, because urban development and redevelopment projects are riskier and less predictable than greenfield projects. Over the past few years, New Jersey's elected officials have started improving public infrastructure and providing developer incentives to encourage investment in some urban areas. PSE&G's TRIP would help ensure that utility infrastructure will keep pace with other efforts to meet expected growth.

"If growth continues unchecked in New Jersey's rural and suburban areas, negative impacts like increased traffic, school overcrowding, and environmental issues will require a substantial investment in infrastructure to maintain or improve residents' quality of life," said PSE&G's Comerford.

According to Comerford, all PSE&G customers would pay a charge for TRIP on their monthly bills. "Redeveloping urban areas better utilizes existing resources. All customers on our system should share in the TRIP costs, because all customers benefit when we gain more ratepayers on existing infrastructure," he said. The charge would function much like an energy adjustment clause. Quarterly TRIP rate adjustments would reflect utility expenditures in targeted areas until those costs could be rolled into new base rates.

TRIP would also include a 2 percent higher rate of return for the investments needed to support growth in the targeted areas. TRIP would recover the annual costs and return on investment for replacement, repair, upgrade, expansion, or relocation of utility assets.

Directing Growth to Match System Capacity

Connecticut-based Northeast Utilities' (NU's) economic and business development department systematically encourages development where adequate or underutilized capacity exists, while at the same time averting needless capital expenditures. The department's first step was to identify and map areas with underutilized utility capacity. An initial review of NU's Connecticut electric system revealed that 132 circuits from 26 substations had available and underutilized capacity. The utility's asset management engineering group, which plans capital investments, verified the circuits that could be targeted for growth without requiring additional investment.[6]

The utility's target areas were marked on road maps where they coincide with existing commercial and industrial (C&I) zoning. The plan is to overlay new properties on the maps as they are preapproved or scheduled for fast development. The information will be made available on a Web site and through the Connecticut Economic Resource Centers. Ultimately, NU wants to add the data to the state's geographic information system, which also allows quick access to other economic and demographic data.

The next challenge will be to share this information with key utility employees, real estate developers, site selectors, businesses, and other partners. A complete business plan for this initiative was under development during the second half of 2003. NU plans to quantify cost savings when development occurs at the targeted sites. It will then consider reinvesting some of its savings to encourage market growth at these underutilized locations before building additional capacity to meet new load elsewhere.

Redeveloping Brownfields

Brownfields—underused properties or abandoned sites that have obsolete facilities or environmental problems—are another example of underutilized capacity. There are an estimated 125,000 to 600,000 brownfield properties in the United States.[7] Many utilities are discovering that it is more cost-effective to revitalize existing brownfields than it is to level new areas and develop them from scratch. For instance, Niagara Mohawk is partnering with the state of New York and five regional colleges to create a state-of-the-art brownfield-remediation training and research center in Utica, New York. The center will provide students, industries, and municipal governments with training programs that cultivate the expertise and skills needed to manage the clean-up and redevelopment of brownfields. The training center will be located on a former manufactured-gas site owned by Niagara Mohawk, which plans a multiyear remediation of this 142-acre site. In addition to this program, Niagara Mohawk also provides grants to fund utility infrastructure improvements and other costs for redeveloping brownfield sites or vacant buildings in its service area, thereby converting a stagnant desert into an oasis of growth.[8]

As utilities seek ways to get nonproducing assets to make money, it's increasingly important to find creative solutions and resources for redeveloping brownfield sites. The U.S. Environmental Protection Agency and other federal agencies offer programs to encourage brownfield redevelopment. A list of resources and federal agency contacts is available online at www.epa.gov/brownfields/iawgcont.htm.

Investing In Underserved Areas

Sometimes adequate gas or electric capacity is not enough to stimulate economic activity in an area. Additional attributes such as roads, railroads, and telecommunications infrastructures are also often necessary. The Los Angeles Department of Water and Power recently committed $1 million to increase telecommunications assets in an underserved part of the city; the Watts Wide Area Network (Watts WAN) provides for the construction of fiber optic rings. Purchasing and installing optical hardware and other related equipment will provide high-speed broadband access to selected corridors in the Greater Watts business community. The Watts WAN is expected to increase investment, create new jobs, and improve the quality of life in the Greater Watts community—ultimately better utilizing existing electric and water infrastructure.[9]

By linking available underutilized capacity with a knowledge of existing customers' expansion needs, key account managers or business developers can effectively put two and two together to achieve a ten for the utility, the customer, and the community.

Attracting New Business to Increase Revenues

Attracting new business to a region is the cornerstone of economic development. It creates new jobs, improves business for existing firms, stimulates new support and feeder businesses, and improves the regional tax base, which benefits the entire community. Utilities have a number of traditional tools to do this, including financial incentives and economic rates and riders, but some energy

Maximizing Power Plant Capacity

In 2000, mining company LTV Corp. closed a taconite mine within a stone's throw of a Minnesota Power generation plant in Hoyt Lakes, Minnesota, eliminating 1,400 jobs and significantly reducing regional load requirements. Transmission constraints in the area limited the utility's ability to sell its surplus power on the open market, so Minnesota Power, an ALLETE company, teamed up with the city to develop the 220-acre Laskin Energy Park next to the utility's 110-megawatt generating plant. This innovative partnership addressed the economic crisis and laid the groundwork for Minnesota Power to better utilize regional power capacity.[10]

The power plant's manager played a vital role in moving this effort forward. Support from the city, legislators, and other economic development groups helped ensure that the park would benefit from road improvements, access to fiber optics, and natural gas service. Land near the power plant has been reserved for firms that would benefit from steam, rail service, or other amenities available close to the plant.

This joint effort has already attracted two business expansions from the Minneapolis-St. Paul area. The new companies invested nearly $4 million in facilities and created more than 30 jobs initially—with plans to grow. An office building that was constructed on speculation by the City of Hoyt Lakes played an important role in landing one of the firms.

Minnesota Power offers incentive rates for companies locating in Laskin Energy Park. The special rates provide declining discounts over four to seven years, depending on the customer's power requirements. Minnesota Power also spearheads marketing for the park, with support from other partners. The economic development team leverages limited resources to market the region through Web-based marketing, print ads, special events, and other cost-effective techniques.

providers are developing new tactics or applying these traditional tools with new twists.

Cooperation and Partnership

From real estate partnerships to database development, utilities are finding creative ways to collaborate with partners and leverage resources to more effectively compete with other regions for new business. Each of these efforts expands the economic development net and helps the region to capture and retain the benefits that result from new business opportunities.

Create real estate partnerships. C&I real estate developers are in the business of selling and leasing space. When utilities and real estate firms share leads and information on available properties as well as support, a greater number of empty spaces are filled more quickly, benefiting the client, the Realtor, and the utility. This was the thinking behind the highly successful SiteFinders program launched by PSE&G in 2001 to formalize an alliance between the utility and area Realtors.

Six of New Jersey's most successful real estate brokerage firms pay a monthly stipend to belong to SiteFinders. They also share both their commissions (a sliding scale up to 40 percent) and any consultant fees (up to 25 percent). In return, PSE&G provides qualified business leads and joint advertising that increases visibility for the brokers. PSE&G's free business-relocation services include: demographics; financial incentives; utility service; information about and analysis of taxes, labor, and transportation; and other factors important to a company's site-location decision. (See sidebar, "Key Site-Selection Factors.")

In its first two years of operation, SiteFinders has referred over 200 business prospects and completed 14 transactions. About 60 percent of the SiteFinder deals to date have involved companies new to doing business in the state of New Jersey. At this point, PSE&G is still footing much of the bill, but after five years, the utility expects to generate enough revenue through SiteFinders' fees to cover 50 percent of the costs of providing the free business-relocation services.[20]

Spearhead regional initiatives. A utility cannot promote its service territory in a vacuum. The attributes of the region, combined with the strength of the utility, can greatly increase the area's desirability.

Philadelphia-based PECO Energy, an Exelon company, was the driving force behind a Web site that extends beyond the utility's service area to better represent the assets of the greater Philadelphia area. Unveiled in May 2003, PositivelyPhiladelphia.com provides comprehensive data for southeastern Pennsylvania, southern New Jersey, and northern Delaware.

Key Site-Selection Factors

Utilities should recognize that energy costs and supply can be far down on the list of selection factors that companies care most about. *Area Development* magazine revealed the following site-selection factors as top priorities for the 110 businesses that responded to its 2002 Annual Corporate Survey. (About 75 percent of the survey respondents were manufacturers.)[11]

1. Availability of skilled labor
2. Labor costs
3. Tax exemptions
4. State and local incentives
5. Highway accessibility
6. Corporate tax rate
7. Proximity to major markets
8. Occupancy or construction costs
9. Energy availability and costs
10. Environmental regulations
11. Availability of telecommunications services
12. Availability of land
13. Cost of land
14. Low union profile
15. Availability of broadband telecom services

It's important to note that although the list above shows the average ranking of determining factors, the driving factors for choosing a site will vary by industry and company. It's essential to listen carefully to what prospective companies say they need—and sometimes dig deeper to discern the pivotal points.

Site-location decisions are on the fast track today. Businesses expect to complete the whole process in about 40 to 60 percent less time than a decade ago, according to Robert Price, senior principal at Lockwood Greene, the global industrial engineering and consulting division of CH2M HILL.[12]

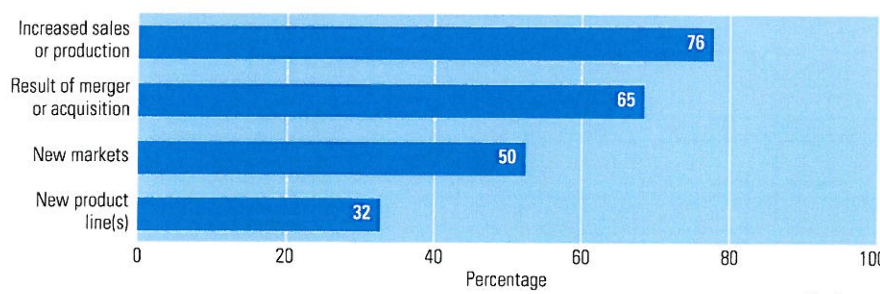
Energy issues will typically be higher than ninth on the list for certain companies in manufacturing such as metal fabrication, food processing, and ceramics. Even within manufacturing, energy demand will depend on where the company is in the supply chain, Price told us. "A company manufacturing components will place a higher priority on energy issues than a high-value-added assembly plant or distribution facility," Price said. "Understanding what will drive the business decision for each project can provide the edge needed to close a deal."

According to *Area Development* magazine, increased sales or production and mergers or acquisitions were the primary reasons companies added facilities in 2002 (**Figure 1**).[13] Correspondingly, consolidation of existing operations, mergers or acquisitions, and lowering costs were the primary reasons for decreasing facilities in 2002 (**Figure 2**).[14] Before a utility can land a new facility, it must understand what decision-makers are looking for in the best location.

The survey results also reinforce the wide range of factors considered in a business location decision. This underscores the importance of utility economic developers helping to ensure that communities are in a strong competitive position and that prospects receive timely, accurate information.

Figure 1: Primary reasons that companies add facilities

About 29 percent of the companies that responded to *Area Development* magazine's 2002 Corporate Survey had increased the number of facilities they operated in the previous year.

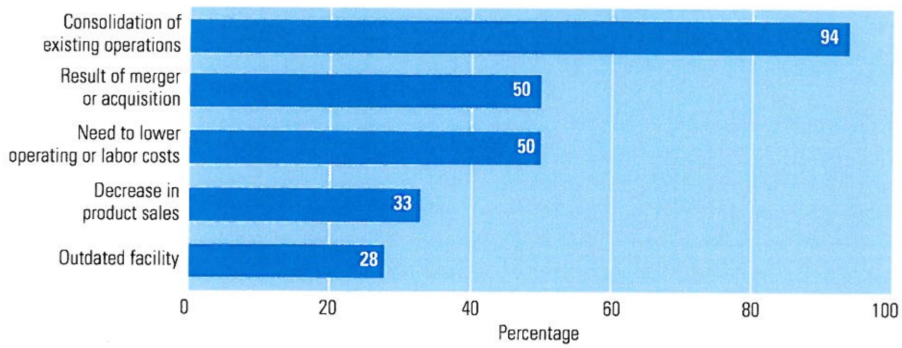


Courtesy: *Area Development* magazine [13]

continued on next page

Figure 2: Primary reasons to close facilities

About 15 percent of the companies that responded to the *Area Development* 2002 Corporate Survey had closed facilities in the previous 12 months.



Courtesy: *Area Development* magazine [14]

"We need to market as a region, because site searches typically examine an entire area first rather than starting with a specific county or community," said Greg Byrnes, director of economic development for PECO Energy.[15] "We recruited a wide range of partners to help support this regional effort, including state, county, and local economic development organizations, real estate brokerages, railroads, and telecommunications firms."

This tri-state initiative was well-received by many elected officials. It complements congressional leaders' efforts to combine forces in this region and more-effectively compete with other states for limited federal resources.

Comprehensive data on the Web site can be printed as reports or downloaded into spreadsheets for analysis—a feature more decision-makers are looking for to help streamline their efforts. PECO Energy promotes the Web site—and the region—through a quarterly newsletter that is distributed to about 3,500 commercial brokers, developers, and site consultants across the nation.

To help propel regional cooperation to the next level, PECO Energy initiated a $12 million to $16 million fund-raising campaign for marketing. This initiative, which is now spearheaded by the Greater Philadelphia Chamber of Commerce, will empower a new economic development group at the Chamber to co-market the region with PECO Energy.

Boost regional cooperation. A consultant's study suggested that New England could become an economic dead end if cooperative efforts were not initiated to promote the region, said David Driver, managing director of regional development for Northeast Utilities. "It's my job to raise visibility for the benefits of doing business in New England, an area historically viewed as an older, higher-cost manufacturing region."[16]

Driver facilitates business development in the six states where Northeast Utilities sells wholesale power or serves retail customers directly through its utility subsidiaries. He meets with site consultants and target businesses so that when they seek new locations they keep New England in mind. Driver also supports the economic development goals of three utility subsidiaries, often getting involved in collaborative efforts that cross state lines. For example, he recruits representatives from each state to help staff the Team New England exhibit booth at trade shows. He also helps manage the information prospects need from multiple states.

"When a site consultant recently called for information, I passed the lead along to the appropriate people in Vermont and found an available building that matched the company's specifications just across the border in Massachusetts," Driver said. "I also connected the client with a similar New Hampshire company that was downsizing its labor force within driving distance of the available building. I responded more quickly with pertinent information from these three states than if the consultant had to seek out different sources in each area."

Another example of regional cooperation is the creation of public-private partnerships—projects that are often times driven by the utility company. Walt Elish, director of economic development at Maine Public Service Co. (MPS), told us that with many local development groups competing with each other for projects and struggling with funding issues, the need for a regional economic development marketing entity became apparent. MPS is leading a public-private marketing initiative that is designed to enhance the region's economic development efforts. This four-year program, administered by MPS and the regional development commission, will have a marketing budget of about $3 million. Its goals include creating an additional 1,500 new jobs and adding $50 million in new investments.[17]

"To raise this kind of money in rural Maine, it's important that we have credible goals and objectives the business community will support," Elish said. "By coming together as a regional entity, we'll develop a marketing program that no individual group could do on its own to promote the assets of this region."

Manage regional data. Utilities have a vested interest in ensuring that accurate information is available online about the communities and available land and buildings that they serve. If sites and communities don't get on the radar for decision-makers during the initial search, they won't have a chance to compete for new investments. Businesses expect instant access to comprehensive data that used to take weeks to gather from states and communities. Consequently, 80 percent of the initial screening for site searches is now done on the Internet.[18]

To meet this need, Aquila developed the LocationOne Information System so that the communities it serves would have an easy way to provide accurate, up-

Typical Information Requested for a Site Search

National data standards allow prospects to easily make "apples-to-apples" comparisons for 1,200 elements in the following 13 categories. The International Economic Development Council provides an Excel file (25 spreadsheets) to help organizations more effectively gather and present these key data elements.[19]

- Available buildings and land
- Demographics
- Education
- Employers/business trends
- Environmental
- Government
- International resources
- Labor force and average wages
- Labor-management relations
- Quality-of-life attributes
- Tax rates
- Transportation
- Utilities

to-date information online (**Figure 3**, page 12).[20] Communities can enter their available buildings or sites and business information in one database that is shared by local and regional groups, utilities, and state agencies. According to Clark Smith, economic development manager at Aquila, the system replaces the cumbersome process of each entity trying to independently manage and update the same information.[21]

LocationOne is getting results. In fact, Smith told us that a company recently viewed a building on LocationOne and purchased it within 72 hours—without even visiting the facility in person.

Prequalify sites. Recently, the State of Pennsylvania discovered that it was losing projects to shovel-ready sites in New York. The State found out the hard way that the timeline for companies relocating is now drastically shorter than it has been in years past. Businesses are now looking to shave time off of their moves by giving preferential consideration to prequalified sites they know will meet their requirements. Utilities can play a pivotal role in this process.

Allentown, Pennsylvania–based PPL Electric Utilities funded the initial research and then participated in a broad-based coalition of utilities, railroads, regional economic development organizations, and state agencies that provided financial and grassroots support to implement a statewide prequalification program called SelectSites or SelecTech Sites. As part of the program, the State of Pennsylvania prequalified sites based on specific industry needs to help companies find locations that could meet tight project schedules. Profiles of industry needs were created for eight types of projects, ranging from heavy industrial to research and development. Some of the factors evaluated included electric and gas capacity, workforce availability, telecommunications infrastructure, and transportation accessibility.

Figure 3: Sample views from LocationOne

Aquila created the LocationOne Information System as an online database of location availability information that can be shared by local and regional groups, utilities, and state agencies. The system has been adopted by eight utilities (Alliant Energy, Ameren, Aquila, Empire District Electric, Iowa Area Development Group, MidAmerican Energy, Nebraska Public Power District, and Omaha Public Power District) and three states (Missouri, Nebraska, and Iowa).

Courtesy: Aquila Economic Development Department [20]

According to Don Bernhard, manager of community and economic development at PPL Electric Utilities, his company saw a significant increase in prospect activity after more than 40 sites in its territory were prequalified through Pennsylvania's statewide site-prequalification initiative.[22]

In fall 2003, the Pennsylvania Department of Community and Economic Development's Team Pennsylvania launched inventPA.com, a Web-based system, to initiate a second round of site selectors' applications.[23]

Financial Incentives and Tools

Money talks, and financial incentives are speaking louder than ever to businesses that are planning new facilities today. As many states struggle with record deficits, utilities are playing an increasingly important role in finding creative financing solutions.

"Companies that didn't consider financial incentives before, or viewed them casually, now evaluate them in a very concrete way," said Jay Biggins, co-founder and president of Stadtmauer Bailkin Biggins LLC, a company that specializes in economic development incentives.[24] "Requests for capital commitments are scrutinized very carefully in businesses today, requiring more burden of proof that projects are needed and are cost-effective. If incentives are not available to help offset a company's risk, projects are often put on hold."

In the early stages of a site search, incentives are just one of the dozens of line items a company evaluates. But when the search narrows to the final few communities, incentives can have a substantial impact on whether or not a project will move forward and where it will go.

Since 1984, Minnesota Power, a division of ALLETE, has sponsored a shareholder-funded program that has provided more than $24 million in financing to help its customers create or retain more than 5,800 jobs. Today, Minnesota Power is revamping the way it provides access to capital, shifting its efforts from investing directly in projects to pooling resources through the Minnesota Community Capital Fund (MCCF).[25]

Minnesota Power helped found MCCF, which is a statewide initiative designed to increase the availability of gap financing in rural areas, in February 2003. So far the fund has attracted more than 55 investors ranging from rural communities with populations under 1,000 to larger cities, such as Duluth and St. Cloud. Members can originate loans of up to 10 times the amount of funds they have on deposit (ranging from $25,000 to $250,000). The loans are then sold on the secondary market, allowing MCCF to continually recapitalize its loan fund.

"Through MCCF, we can originate loans up to $2 million and protect Minnesota Power's investment and risk level," said Nancy Norr, Minnesota Power's manager of economic development. "In a few cases, Minnesota Power may still play a direct financial role in projects that are energy intensive and/or have a major economic impact."[26]

For example, Minnesota Power recently provided a $500,000 loan as part of a $5 million financing package that enabled a start-up paper mill to open in Brainerd, Minnesota. The new firm moved into a paper plant that had closed in 2002; it plans to employ about 260 people by late 2003. Minnesota Power will be the wholesale provider for this mill's 8- to 10-megawatt (MW) electric load.

Utilities often provide a critical piece of financing needed to leverage resources from other partners and close a deal—from equity investments to financing debt or energy-efficiency measures. They can further sweeten the deal by focusing components of their existing demand-side management (DSM) programs, which offer equipment leasing, rebates, and other incentives to new businesses. Efficiency incentives at the onset can be far more cost-effective than a later retrofit.

Some utilities will even finance the buildings themselves. For instance, Wisconsin Public Service Corp. has invested $3 million as debt or equity in 15 speculative buildings or expansion projects. Over the past 10 years, these projects have created about 1,000 jobs. The utility's participation in each project ranged from $50,000 to $650,000. When the utility's participation involved equity, it took ownership in the facility; most of the loans are structured with buyouts at the end of five years. All funding for this program is with below-the-line shareholder dollars—that is, dollars that are not included in the rate base.[27]

Similarly, Raleigh, North Carolina–based Progress Energy offers a rotating Industrial Building Fund to finance speculative shell buildings for manufacturing. The utility partners with communities, providing one-third of the project costs interest-free for up to 36 months ($400,000 maximum per project). Since 1997, Progress Energy has financed five buildings in North and South Carolina through this rate-funded program.[28]

Duke Power, based in Charlotte, North Carolina, also stimulates business growth—with up to $1 million in grants awarded each year in both North and South Carolina. Matching funds or in-kind resources are typically required to receive the utility's shareholder-funded grants. A wide range of development activities may qualify for grants, including redeveloping or jointly advertising buildings served by Duke Power, constructing new speculative buildings, developing sites and business parks, and supporting new or expanding businesses.[29] Utility revenue and projected growth are evaluated to determine whether a project meets Duke Power's internal rate of return and payback requirements. Grants are typically awarded through a local development organization (LDO). The LDO signs a performance agreement and oversees the project. It ensures that the grant dollars are used properly and that contract provisions are fulfilled. If the performance metrics are not met, Duke Power can require repayment of the grant.

Lastly, the Los Angeles Department of Water and Power (LADWP) budgeted $9 million in the 2002–2003 fiscal year for a loan program that helps customers pay for utility infrastructure or energy/water efficiency improvements. LADWP provides customers with unsecured, short-term capital for the utility infrastructure that is necessary to provide electric or water service. Loans for utility infrastructure must be repaid within three years; loans for equipment that improves energy or water efficiency can be financed for up to 10 years.[30]

Economic Development Rates and Riders

Sometimes regional information, cooperation, and financial support may not be enough on their own to attract businesses to a region. Utilities might also need special economic development rates and riders. With the U.S. economy in a slump and global competition heating up, some regulators have a renewed interest in how incentive rates can be equitably structured to encourage job creation, according to David Svanda, Michigan commissioner and president of the National Association of Regulatory Utility Commissioners.[31]

"Manufacturers today face tremendous global pressures that weren't present 10 or 15 years ago," said Svanda. "We need to be responsive to the changing conditions—recognizing what can be done at the margins while making sure other customer classes are not damaged in any way."

Industrialized states have probably spent more time focusing on this issue because of the vital role manufacturing plays in their economy, Svanda noted. Regulators approach incentive rates in different ways based on the unique issues in each state, such as demographics, economic drivers, and other underlying factors.

Entergy Mississippi received approval from the state's Public Service Commission on an incentive rate that can be offered for up to five years on new load. Starting in October 2003, a credit of $0.005 per kilowatt-hour (kWh) will be available to new or expanding businesses that maintain a monthly load factor of 50 percent or greater, use at least 200,000 kWh per month, and have 20 or more employees. Customers must agree to at least a five-year contract, with the incentive credit available for 60 consecutive months. Businesses must also confirm in writing that this rate was a key factor in their decision to expand or locate in Entergy Mississippi's service area.[32]

"The new incentive rate enhances Entergy Mississippi's position as we compete regionally for projects," said Steve Kelly, community development manager.[33]

Utilities have a unique opportunity to offer incentives that can be tailored to support public policy, target specific buildings or industries, or direct investment to sites with available or underutilized utility capacity. The following examples illustrate how incentive rates are being used to meet customers' needs and utility goals.

Filling vacant buildings. Duke Power's Economic Redevelopment Rider encourages growth where the utility can maximize existing infrastructure. To qualify, a business must move into a vacant building that has been empty for six months or more, must not require any new investment by the utility, and must agree to stay in the building for a minimum of five years.[34] The business must also use at least 500 kilowatts (kW) of load and either invest $200,000 per 500 kW of load or create 35 full-time jobs per 500 kW of load.

In return, the company will receive a 50 percent discount on energy rates for one year (starting any time it chooses in its first 12 months in the building). If the business doesn't fulfill its contractual requirement to stay in the building for five years, it must pay back the incentive to Duke Power. Seven Duke Power customers, with a combined load of 12,000 kW, were participating in this program in 2002.

Supporting enterprise zones. Utilities often gain approval on special rates that complement a state's financial package and economic development goals for targeted areas. These state-designated zones are typically plagued by high unemployment rates or target the growth of certain types of industries, such as high-tech firms.

For example, the LADWP offers special electric rates for five areas in the city that the State of California calls Enterprise Zones (**Figure 4**).[35] Companies that are either newly located in these zones or that increase their consumption by 50 percent or more may qualify for discounts on electric rates. The discounts start at 35 percent the first year and drop to 10 percent by the fifth year. In fiscal year 2001–2002, LADWP provided Enterprise Zone businesses with about $6.2 million in electric rate subsidies.[36]

Niagara Mohawk, in Syracuse, New York, offers up to 10 years of deep discounts on incremental energy consumption for qualifying companies in the 34 New York State Empire Zones it serves. In 2002, companies that were adding new electric load or qualifying new-to-New York companies moving into these zones benefited from rate discounts estimated at $13.7 million. Growing customers can save up to 50 percent on standard electric delivery rates, depending on their service classifications, delivery voltages, and energy-use profiles. Discounts on natural gas delivery range from 3¢ to 5¢ per therm, depending on a company's service classification and consumption. Niagara Mohawk's discounts don't affect base rates for other customers—the utility foregoes higher revenue on this potential incremental load in the short term to encourage investment and job creation in its service area, which can pay off in the long run.[37]

Outside the Empire Zones, Niagara Mohawk can offer negotiated and standardized incentives to growing businesses or new-to-New York firms. For business attraction, its Service Classification No. 12 program offers a five-year declining discount on the qualifying kilowatt-hours used. A small or midsize manufacturer could save about 35 percent on electric delivery rates in the first year. This program also gives the utility flexibility to negotiate special contracts with energy-intensive businesses or large employers that have more than 300 jobs at stake.[38]

Competing with other states. Incentive rates are a useful tool when several states are competing for new investment. For example, Des Moines, Iowa–based MidAmerican Energy can offer special rates for up to five years to help Iowa businesses through the early stages of expansion or start-up.[39] In order to qualify for a lower rate, the Iowa Utilities Board requires a project to meet stringent criteria, including the following six.

Figure 4: Los Angeles Central City Enterprise Zone

The City of Los Angeles contains five state Enterprise Zones, including the one pictured here. Businesses located within these zones, which were designated by the State of California, are offered special tax credits and incentives, including special electric rates from the Los Angeles Department of Water and Power. The zones were created to stimulate local investment and employment.

- A cost/benefit analysis must show that offering the discounted rate to land the customer will result in a greater benefit for the utility than if the customer located elsewhere.

- The company's load factor must not deteriorate the system's load factor.

Division Data Request 16-4

Request:

Re: page 4 of 15, line 22, through page 5 of 15, line 8, of the testimony of witness Fields. Please:

a. Provide supporting data and documentation for the closeness of the relationships that the Company has built and maintained with "*key commercial and industrial customers*;"

b. What criteria does the Company use to identify the customers who would be considered by the the Company as "*key commercial and industrial customers*;"

c. Provide the basis, including any studies, surveys and other documents upon which the Company relies to assess the extent to which "*key commercial and industrial customers*"

   i. View the Company as a "*trusted advisor*" on energy issues;
   ii. View the Company as a "*trusted advisor*" on non-energy issues.

d. For each identified key commercial or industrial customer, provide actual kWh sales by account for the last five years;

e. Please identify all sites and buildings in Rhode Island that the Company has identified to date as "*Shovel Ready*;" and

f. Provide the criteria upon which the Company relies to assess whether a site or building is "*Shovel Ready*."

Response:

a. The Company has a staff of Account Executives dedicated to managing relationships and providing service to key commercial and industrial customers. Currently there are approximately 180 Rhode Island customers who are considered "Key Accounts" and who receive this dedicated support. Each year, the Company conducts a customer satisfaction survey aimed at these key accounts, and the results have historically reflected a close relationship between the Company and these customers. For example, the results of the 2009 survey indicate that 83 percent of key account customers are highly satisfied with National Grid, rating the Company at least a "6" on a 10-point scale. In the same survey, 91 percent of Rhode Island

Division Data Request 16-4 (cont.)

key account customers responded that they were highly satisfied with the performance of their National Grid account executive.

b. Key Account customers are the Company's largest customers in terms of energy usage, revenue, and other indicators. Some customers may be on the key accounts list because they are associated with major municipalities in the Company's service territory, or because they have complex service issues that require more involved communications with the Company.

c. Beginning in 2009, the Company's annual Key Account satisfaction survey includes questions that gauge the degree to which customers view the Company (specifically their Account Executive) as a "trusted advisor." The survey results indicate that 69 percent of Rhode Island key account customers consider their National Grid account executive to be "a trusted energy advisor whose knowledge has benefited my organization's energy business decisions." In addition, 62 percent of Rhode Island key account customers surveyed feel their Account Executive "possesses deep insight into my business and industry," a statement which addresses both energy and non-energy needs. The Company considers these survey questions to be important measures of its relationships with key customers, and will continue to track these results in future years.

d. As a policy, the Company does not disclose energy usage information for individual customers. This confidentiality policy is one reason that many key account customers consider the Company to be a "trusted adviser." Instead please see the attached (labeled RI Key Account Customers) kWh usage history for each Rhode Island key account customer, without the customer name or other identifying information. It should be noted that the total number of accounts on this list is far larger than the 180 described Part "a" above. This is because many key account customers have more than one electric account.

e. The Company has not yet compiled a list of "Shovel Ready" sites and buildings in Rhode Island. This review will be conducted during the proposed 180 day collaborative process with key economic development stakeholders. In the meantime, the Company has had preliminary discussions with economic development officials in Rhode Island, in order to begin its assessment of key commercial/industrial sites and buildings in the service territory.

f. For its Upstate New York program, the Company relies on designations by state economic development officials through established programs such as "Shovel-Ready NY" and "BuildNow NY." With or without such formal designations, the

Division Data Request 16-4 (cont.)

intent in Rhode Island will be to identify sites that have strong development potential, which have already generated interest among potential investors, and which can/should be marketed as "fast track" development sites for job-creating companies.

National Grid Rhode Island Key Account Customers

Note: Many key account customers have multiple electric accounts

Acct#	Acct Name	Svc Town	Rate	2008 Kwh	2007 Kwh	2006 Kwh	2005 Kwh	2004 Kwh
		Providence	G32	6664000	7096000	6738000	7116000	6644000
		Johnston	G3F-G	2453400	2994000	3352560	3566160	3638760
		Lincoln	G3F-G	3204723	3102750	3783150	4644150	4719750
		Esmond	G3F-G	5436400	3250800	0	0	0
		Esmond	G3F-G	1744800	842000	0	0	0
		Rumford	G32	5228000	5214000	5689000	4540000	4890000
		E Greenwich	G32	2279000	2303000	2106000	1946000	808000
		West Kingston	G3F-G	5234723	5872800	6696000	1068300	171000
		West Kingston	G3F-G	3217927	2885600	2704000	2532800	2249000
		Lincoln	G3F-G	6056949	6002500	5240200	5510400	5505500
		Lincoln	G32	1862160	1740480	1718640	1966080	1984800
		Lincoln	G32	1817900	1911000	1846600	1819300	1922200
		Lincoln	G32	1370880	1331040	1430160	1591040	1808800
		Warwick	X01	25611410	25009200	22021200	21007800	26308800
		West Warwick	G32	8191220	8320000	8239000	7895000	7849000
		West Warwick	G32	4318000	4332000	4724000	4623000	5281000
		Pawtucket	G3F-G	1882880	1820160	1608160	1779680	1854880
		E Providence	C06	18724	22512	20650	21921	20262
		Coventry	G32	6614313	7193600	7101800	7734800	6841000
		Fiskeville	G32	1269800	1353400	1282200	1387800	1436400
		E Providence	G3F-G	4996800	1086000	1246800	156000	0
		Riverside	G3F-G	4441000	5211000	5245000	1286000	0
		Lincoln	G32	3790500	4023600	4213300	4334400	4111100
		Providence	G32	16536000	15228000	14775500	13577000	13855500
		Providence	G32	5001000	5409000	4983000	5011500	4315500
		Warren	G3F-G	1890600	1824360	1987500	1870440	3289860
		Providence	G32	3337320	3541980	3325500	3252180	3258480
		Providence	G32	1412520	1474320	1388800	1407840	1288960
		Providence	G32	1055600	1066400	1101200	994800	926000
		Providence	G32	1008000	1112800	1014000	1096800	1026400
		Westerly	G3F-G	665100	62400	0	0	0

Westerly	G3F-G	3182000	4607000	4553000	5468000	5724000
Westerly	G32	816000	1488600	1482600	1623400	1822800
Riverside	G32	1706640	1549680	1471200	1394640	1246720
Providence	G62	70490482	76302800	68810900	67794600	65746800
Providence	G32	6181142	6216600	4206000	0	0
Providence	G32	3843000	3765000	3466500	3684000	3961500
Providence	G32	1181600	1143200	0	0	0
Providence	G02	719400	740400	745800	780600	388200
Providence	G02	546600	622600	0	0	0
Providence	G02	274080	204000	243840	210015	352865
Providence	G02	233120	319520	0	0	0
Providence	G02	116160	123280	108560	89760	171200
Esmond	G3F-G	10050809	9097200	8360400	13701600	16456800
Esmond	G3F-G	7165200	7174300	12355500	2372400	0
Providence	B32	3346758	3714000	3228000	5670600	4224960
Woonsocket	G32	4274400	4392800	4617200	4596000	4726400
Woonsocket	G02	177600	166500	160200	161100	156600
Woonsocket	G3F-G	1986560	2178560	1927360	1613440	1286080
Woonsocket	C06	37971	57329	59842	52526	35483
Woonsocket	G32	22146785	18775000	15705000	14432000	12116000
Woonsocket	G3F-G	3057000	3074250	2925900	2924700	2764800
Smithfield	G02	1213000	1263600	1129200	1079400	982600
Lincoln	G32	3773400	3511800	3437700	3100500	3283800
Warwick	G32	488800	486800	565600	535600	675400
Wood River Jt	C06	1240000	3212000	4500000	5508000	5216000
Cranston	G3F-G	5848000	6828000	6605000	6070100	4787400
Rumford	G3F-G	5783558	4505250	3527250	1274250	0
Riverside	G3F-G	9330658	10092000	11525250	12841500	10543500
Riverside	G02	568826	589920	550800	701520	694800
Cranston	G02	585680	613600	545760	560960	272000
Riverside	G32	3184920	3186240	3258048	3251616	3272256
E Providence	G32	929200	984000	950800	979600	925600
E Providence	G02	419840	406160	414880	393920	394640
E Providence	G02	257760	250320	241280	265600	254240
Rumford	C06	37045	42691	32217	37370	32091
E Providence	G02	132160	131400	128880	133520	134040
Newport	G32	1851680	1696000	1664480	2049760	2497440

Portsmouth	G3F-G	688560	790000	722560	746960	816480
Portsmouth	G02	447040	402240	362560	329280	378560
Newport	G02	378200	485560	470000	524640	494560
Newport	G02	257320	251360	247880	232800	219080
Middletown	G02	207250	216650	111550	188200	35600
Newport	C06	37823	38962	35610	35921	34646
Newport	G32	2553300	2544000	2665200	2793000	2638200
Newport	G02	580500	601500	495300	666300	515700
Providence	G32	3985200	4593600	4558200	4366200	4265400
Providence	G3F-G	2081400	2225600	1880800	1978880	2046200
Providence	G32	694400	783320	796600	800800	789040
Warwick	G32	3229500	3311250	2998500	2848500	2772000
Warwick	G3F-G	1976600	1891800	1873800	1980600	2063600
Pawtucket	G32	5020080	5545400	5348000	4568900	5348700
Pawtucket	G32	2126600	2180500	3965500	3959550	4530750
West Warwick	G32	3686400	3859600	4172000	4636000	4593200
Cranston	G3F-G	489600	570216	803760	681672	786768
Warwick	G32	3381000	3292200	3360600	3415200	3386400
Woonsocket	G32	1330800	1284640	1281640	1140880	1094880
N Smithfield	G32	2200440	2123640	2197080	2416560	2423520
Woonsocket	G3F-G	2229750	2322000	2365800	2095500	2121300
Warwick	G3F-G	408000	417600	419400	477600	572700
Saunderstown	G32	3184800	3140400	2801200	2933600	2921200
Narragansett	C06	1564	28	0	0	0
Providence	G3F-G	2070000	2830500	3529500	3871500	3666000
Providence	G3F-G	2554500	0	0	0	0
Riverside	G02	489600	450400	548800	552000	537600
E Providence	G32	845700	848700	821100	841500	820290
Riverside	G02	326400	325600	306000	311600	378400
E Providence	G32	238920	237520	499440	618120	778640
Riverside	G02	120880	118560	119120	126640	134080
E Providence	G02	94560	84720	91200	94320	100960
E Providence	G02	84720	84160	88480	90000	99600
Riverside	G02	48800	43760	38160	47000	50880
E Providence	G02	420640	442560	439200	485280	454880
E Providence	G32	1089060	1091880	1100820	1103640	1321680
E Providence	G02	143680	147520	167040	135360	150400

E Providence	G3F-G	321000	1292600	2589600	3536900	4011600
E Providence	G3F-G	95000	67000	39000	58000	84000
N Kingstown	G62	34079943	40586000	30896000	34203000	34101000
N Kingstown	G02	62342	62577	62729	64235	58115
Pawtucket	G32	2076900	2954000	3747800	4120200	5298300
Pawtucket	G32	1668100	2111200	2352700	2429700	2885400
Riverside	G02	16500	43738	69536	22873	109542
Chepachet	G32	6223794	5742000	5281200	5109600	5190000
Smithfield	G32	7547759	8129250	7572000	7464000	7776000
Smithfield	G32	7109355	8660000	8510000	8162000	7959000
Smithfield	G3F-G	666750	0	0	0	0
Esmond	G3F-G	241300	0	0	0	0
Esmond	C06	46620	55101	70199	63559	48424
Providence	G3F-G	3184000	3578000	3702000	3882000	3694000
Providence	G32	4509728	4589300	4595200	4652700	5164900
Central Falls	G3F-G	1118400	1042800	36000	0	0
Lincoln	G32	293600	339000	368400	465200	492000
Providence	G32	3630000	3783000	3580000	3713000	3586000
E Providence	G32	4908700	5478200	5620900	6158300	5759900
N Kingstown	G3F-G	3244800	3210000	3491200	3095000	2901000
N Kingstown	G3F-G	2293200	2206800	2072200	1959000	1684000
E Providence	C06	17300	0	100	0	60300
W Greenwich	G3F-G	5156250	4455000	0	0	0
Lincoln	G32	13442800	13722800	14656600	15327200	15997800
Westerly	G32	7523000	8020000	9266000	9316000	10589000
Westerly	G32	6262000	7119000	7516000	6799000	7416000
Warwick	G3F-G	6316800	6878400	7065600	6787200	1953120
Rumford	G3F-G	345000	2028000	901200	936300	1273800
Hopkinton	G32	3227760	3209880	3828360	4897020	4676880
Hopkinton	G02	404720	434240	621760	673520	684240
Lincoln	G32	5902080	7125360	7483680	6837600	6791280
W Greenwich	G3F-G	4530000	4454000	4756000	4610000	4753000
Coventry	G3F-G	2127800	1912400	1985800	2014700	1944900
Providence	G3F-G	2044000	1962000	0	0	0
Rumford	G3F-G	4303000	3826000	3546800	3628900	3653800
Pawtucket	G32	4715200	5597200	5180000	5681200	5961200
Central Falls	G32	700800	715200	763200	940800	945600

Pawtucket	G02	430200	443040	464160	471480	480960
N Kingstown	G3F-G	2839000	3295000	1714000	0	0
Johnston	G32	10198989	9544800	8799000	10296800	10706000
Woonsocket	G02	719760	668400	387600	0	0
Cumberland	G32	5812800	6203400	6032250	6305250	7362600
Providence	G3F-G	818200	802600	813160	807080	814780
Newport	G32	3797664	4084500	4105500	4555500	4509000
Newport	G32	1501800	1409100	1439100	1494000	1458900
W Greenwich	G6F-G	49224690	55926000	42102000	41616000	38599200
W Greenwich	G62	15594809	26732000	28329000	28715000	26315000
W Greenwich	G32	945600	2103200	5994800	5416000	5005600
W Greenwich	G02	250160	480080	459440	459920	501760
N Providence	G3F-G	3657000	3747500	3624800	3731500	4045700
Pawtucket	G32	3178000	3682000	3821300	4154500	4146100
Pawtucket	G32	832650	899850	894600	948150	897750
Rumford	G3F-G	4360800	3050400	4132800	5800800	6160800
Cumberland	G32	638080	606400	812320	869120	988960
Warwick	G32	3796800	3718400	4731200	5361600	4931200
Providence	G3F-G	1791600	1846000	1822800	2026000	1960160
Providence	G3F-G	584983	768640	387360	0	0
Providence	G3F-G	477677	528160	273920	0	0
Providence	G3F-G	449143	605920	306560	0	0
E Providence	G02	417120	448160	496640	485280	490240
Providence	G02	404560	363280	380080	438720	397520
Providence	C06	96634	90974	0	0	0
Cranston	C06	22800	21440	18320	17360	38360
Providence	G3F-G	795115	674160	785200	805280	846400
Providence	G02	200320	186720	194000	181120	189680
Providence	G3F-G	4616000	4590000	4605000	4478000	4683800
Providence	G3F-G	1903200	1757400	1703760	1774860	1678500
Providence	G3F-G	1552400	1470240	1429760	1371440	1334000
Providence	G3F-G	1508800	1384800	1352800	1455200	1382920
Providence	G3F-G	1272800	1210880	1047520	861280	758400
Providence	G3F-G	1190474	1211040	1182400	1351248	1297568
Providence	G3F-G	1026800	1073200	1042240	1008640	1060160
Cranston	G3F-G	933180	1610311	798288	1075104	1151568
Providence	G3F-G	828000	751520	736016	804512	791360

Providence	G02	545803	382560	423840	338720	352320
Providence	G3F-G	323233	303520	326880	303520	289456
Providence	G02	149390	156577	139858	140456	165499
Providence	G02	86480	160320	37920	92960	91520
Providence	C06	47949	57297	57169	52996	64418
Providence	G02	296960	251200	238720	265600	260320
Warwick	G3F-G	2876200	3340000	3149800	3184600	3196600
Warwick	G32	9609622	9675600	9273600	9183600	9903700
Kenyon	G32	15506357	14756400	13564800	13111200	14281200
Cumberland	G32	6398700	8925000	7910700	7801500	7302750
Woonsocket	G32	5425000	5597900	5320700	5322100	4961600
Warwick	G32	7552800	7622400	7065600	6501600	6228000
Lincoln	G32	12216000	13128000	12840000	10476000	9690004
Pawtucket	G32	10299684	11027000	10910000	10907000	10600000
Johnston	G6F-G	10020000	10704000	9600266	0	0
Warwick	G32	5872800	6228000	6163200	6559200	6787200
Pawtucket	G32	4886162	4561200	4968000	5812800	5840400
Pawtucket	G32	1140709	1086050	1183000	1608950	1363600
Providence	G32	18079783	16401600	12837600	12655200	12949200
Riverside	G32	4396800	4892800	4356800	5448000	6134400
Riverside	G02	700300	869900	818600	799400	801800
Riverside	G02	196272	186140	157462	161109	177492
N Kingstown	G02	316800	354480	361680	345840	359520
N Kingstown	G02	283760	298000	308720	303040	292240
N Kingstown	G02	278000	274800	247600	254600	279800
N Kingstown	G02	275920	379760	295920	332080	222240
N Kingstown	G02	197040	206560	198560	214160	206880
Providence	C06	1127	304	1328	89	0
Providence	G32	13820000	14352000	13916000	17288000	17964000
Rumford	G32	12150000	10976000	11272000	10110000	5312000
Providence	G32	1313800	1333000	1163600	1152200	1087800
Providence	G3F-G	1005600	0	0	0	0
Pawtucket	G3F-G	1023200	1182200	1131800	1188400	1298800
Smithfield	C06	1008	1447	1685	4708	5423
Smithfield	G32	1379200	1401200	1300400	1675200	1858000
West Warwick	G32	1222800	1165200	1376400	1597800	1699800
Newport	G32	10535670	10470000	11017000	11238000	10758000

Newport	G3F-G	3294857	4246000	4012000	4011000	4037000
Newport	G32	5169277	5105000	4927000	5700000	6162000
Newport	G32	641000	719600	691800	689200	685400
Newport	G32	800200	747600	746800	777800	799800
Newport	G32	737700	716400	698100	705900	742500
Newport	G02	81480	77560	80400	86960	79960
Cranston	G32	5527000	6026000	4426000	4329000	3824000
N Kingstown	G3F-G	4383983	4208250	3606000	3099750	0
N Kingstown	G32	708800	954400	1342400	2184400	2586400
Cumberland	G3F-G	3526400	3884000	3279200	3226400	3367200
E Greenwich	G3F-G	1480400	1552400	1441400	1342400	796000
Providence	G32	5100000	4015500	4768500	5436000	5328000
West Warwick	G32	6177600	6791700	6827100	8269500	7820400
Central Falls	G32	15755383	17682000	18312000	17866800	17480400
Central Falls	G3F-G	4340046	4191600	4562950	4485950	4304650
N Providence	G32	6154800	8688000	8599200	8468400	8130000
Pawtucket	G32	4527360	4840320	4268400	3835440	4343760
Pawtucket	G32	1484640	1664880	1492680	1679280	1671240
Pawtucket	G32	2552962	2904000	352000	0	0
Pawtucket	G3F-G	377100	414900	360900	389700	616200
Pawtucket	G02	222200	257200	501200	831600	1067400
Pawtucket	G3F-G	6525400	824600	0	0	0
Pawtucket	G32	1386013	5189800	4979800	5566400	5448800
Cumberland	G3F-G	758000	1871600	1168400	43200	0
Cranston	G32	4865000	5189000	4409000	4889000	5144000
Warwick	G32	3389850	3024075	3002400	1334775	0
N Smithfield	G32	15634078	14922600	15972600	16321200	18433800
N Smithfield	G3F-G	1844150	1328950	1279950	834750	0
N Smithfield	G3F-G	475200	498000	382800	407400	424200
Pawtucket	G3F-G	3954485	4054400	4076800	3873800	3953600
Providence	G3F-G	23344000	21160000	22096000	22350000	22234000
Providence	G3F-G	5580000	6052000	6032000	7060000	6632800
Providence	G32	4030884	4114500	4306300	4554400	4519900
Providence	G32	4664000	4728000	4590000	5084000	4554000
Providence	G3F-G	1316800	1942400	2441600	3523200	2784000
Providence	G32	1077540	1184520	1195380	1206780	1159860
Providence	G32	973200	1169000	1156000	1204200	1542000

Providence	G3F-G	929000	1123000	1158000	1296000	1261800
Providence	G32	831300	999500	998400	943500	869600
Providence	G32	748020	877560	952620	955500	938340
Providence	G32	705750	793500	854250	918000	945000
Providence	G32	606600	681600	691400	751400	779600
Providence	G32	564225	649650	575775	609075	608550
Providence	G32	485840	651720	685320	680480	755440
Providence	G32	438000	558800	574600	638600	601800
Providence	G02	366720	441760	528800	529120	543200
Providence	G02	355200	501600	455200	396000	393600
N Kingstown	G02	127880	160480	165000	162640	161200
Warwick	G32	996000	1043200	1060800	1030000	1021200
Providence	G3F-G	2306400	2973780	2515800	2302980	2467980
Providence	G32	2134400	2156400	2094800	2348000	2108800
Providence	G3F-G	2003400	2085000	2757600	1255800	2081400
Providence	G3F-G	1994080	1975856	1958808	1862592	1467504
Providence	G3F-G	1810800	1649400	1624800	511800	0
Providence	G02	1381800	869700	540000	479400	372900
Providence	G32	1142400	1163700	1133400	1116600	1200860
Providence	G02	678000	733200	755400	335400	0
Providence	G02	250320	259920	253520	268160	277520
Providence	G02	179040	173520	181760	149600	122240
Providence	C06	29686	34687	30648	35544	36698
Providence	E40	25120	36720	24720	34000	18736
Providence	C06	40	0	0	0	1680
Providence	C06	0	0	0	1	0
Portsmouth	G62	16609654	18085000	17690000	20296000	20471000
Providence	G32	44448218	40053400	36454900	33730500	32611100
Providence	G32	4299960	4404120	4210260	3954300	3723900
Providence	G32	1941000	1749000	0	0	0
Providence	G32	1636360	1755760	1819200	1781680	1626160
Providence	G02	268606	284827	286465	33682	0
Providence	G3F-G	258800	0	0	0	0
Coventry	G32	7731900	8028000	7599600	7143300	5987700
N Kingstown	G32	3647400	3342600	3118200	3408000	3354000
Warwick	G32	10749579	11252000	11402000	11350000	11136000
Warwick	G02	439680	447920	456320	519280	534240

Warwick	G3F-G	315790	0	0	0	0
Warwick	G02	123600	371900	36100	0	0
Providence	G32	6450686	6513500	6135500	6154100	6671600
Johnston	G02	880560	812160	471600	65700	27360
Johnston	C06	47	50	30	35	39
Johnston	G3F-G	3243600	3226800	3280560	3457920	3646200
Johnston	G02	689400	798600	798600	775200	553800
Johnston	G32	40500	0	0	0	0
Providence	G3F-G	1832400	1729600	1348480	119040	0
Providence	G02	472960	0	0	0	0
Pawtucket	G32	1480800	1564200	1587600	1714800	1794000
Bristol	G32	1733000	1925000	1606000	1765000	1727000
Bristol	E40	411600	448640	362240	429840	380960
Bristol	G32	7482348	7872000	6987200	6444800	6257600
Bristol	G32	2580000	2873600	2867200	2996000	2936000
Bristol	G32	2551400	3505600	3404800	3204800	2868800
Portsmouth	G3F-G	1022800	1055600	1027680	1451920	1396640
Bristol	G02	613440	589760	576960	626080	649600
Bristol	E40	262400	266400	209600	223600	209200
Portsmouth	G02	99520	125520	125120	128640	119280
Bristol	G32	7170600	8309200	8501000	8617800	7282200
Newport	G02	1020640	991040	940000	716640	681600
Newport	G3F-G	837880	755560	824680	854320	857200
Newport	G02	298720	318280	329360	253360	215760
Newport	G02	187880	202440	205680	182240	192560
Newport	G02	134480	140640	148160	135440	138440
Newport	G02	512720	552080	513120	591360	597120
Newport	G3F-G	1069560	1051920	1015800	1024800	993720
Newport	G02	383787	316022	290840	263017	251695
Newport	G02	265200	278400	196200	195800	207800
Newport	G02	135760	132360	133880	144040	141680
Newport	G02	75775	56502	65431	63667	67479
Newport	G02	63694	71196	69830	81147	72125
Newport	G02	39632	42515	41366	41152	38752
Newport	G02	409600	413680	407600	430240	438800
Newport	G02	245440	78560	0	0	0
Newport	G02	171680	195560	187640	204800	174520

Newport	G02	52480	54000	54920	56920	56680
N Kingstown	G32	2291000	2434000	2467000	2121040	1578600
N Kingstown	G32	2690400	2011200	1507200	1560000	1576800
N Kingstown	G3F-G	1199200	1354000	753600	855800	816200
N Kingstown	G32	334800	360400	701600	1195600	497600
Peace Dale	G32	9624960	8196120	7850400	7473360	7334280
Esmond	G32	6924400	6754000	7062000	7284000	7000000
Smithfield	G32	5762000	5487000	5066000	5841000	5642700
Middletown	G32	2475600	2736000	2841200	2873600	3135200
Middletown	G3F-G	876400	707120	716480	747040	793520
Middletown	G32	551600	625900	614500	734100	58400
Providence	G32	3721500	3666000	3534200	3674600	3606900
E Greenwich	G62	15501000	15864000	17775000	19602000	18627000
N Kingstown	G3F-G	5620500	6340500	5890500	7402950	5224650
Cranston	G32	6410702	6962400	6734400	8006400	7411200
Lincoln	G3F-G	2626050	2711100	2634450	2803500	2830800
Providence	G32	3684000	3925200	3910200	3573000	3517200
Warwick	G3F-G	2634000	2853600	2738400	681600	0
Providence	G32	12917400	13027000	14537800	13985800	14237800
Warwick	G32	9932519	10411200	9842400	10288800	10440720
Lincoln	G32	2826400	2295200	2308400	2677600	2477200
Lincoln	G32	2387200	1803200	1706000	2006400	1882400
Lincoln	G32	2086000	2121200	1850400	2000400	1792000
Lincoln	G32	1996200	1515900	1423800	1682100	1627800
Burrillville	G3F-G	5100750	5020500	4310250	3626250	862500
Burrillville	G3F-G	3875250	3630750	3620250	1811250	654750
Woonsocket	G32	3184320	3413600	3331040	3451680	3056480
Woonsocket	G3F-G	6280050	3445050	0	0	0
Cranston	B32	2167836	1931800	0	0	0
Woonsocket	G32	8492586	9957600	8226000	8571600	8452800
Lincoln	G32	6388200	7463400	8290800	7612500	8322300
Lincoln	G32	1686300	1770300	1789200	1810200	1877400
Pawtucket	G62	13593600	15480000	18302400	19303200	19612800
Providence	G32	4739800	5113200	5309000	5357200	5324200
Cumberland	G32	5482400	5667200	5846400	5773600	5980800
N Kingstown	B62	96510341	100587200	94662800	99487200	150390800
N Kingstown	G32	7875560	8725000	8514000	8190000	8212000

N Kingstown	G32	2225400	2546400	2445000	2499600	2605200
N Kingstown	G02	108800	109680	100320	108080	108720
Narragansett	G32	1346071	1337400	1312200	1345800	1382220
West Warwick	G32	4993000	6263000	5909000	6087000	4312000
Westerly	G02	731400	667600	679100	745900	781300
Westerly	G02	459100	481800	452300	518600	435100
Westerly	G02	306480	328080	308480	333280	311920
Westerly	G02	232640	245440	241760	229920	236000
Westerly	G32	2390317	2322900	2386980	2342880	2211804
Lincoln	G6F-G	30304768	29615600	19322800	15437800	13202000
Newport	G02	142516	70317	51777	53902	55139
Newport	C06	7664	6021	4474	7706	6687
Portsmouth	C06	21943	13997	16453	18200	15849
Newport	G6F-G	106649000	100653000	103945500	109231500	111364500
Warwick	G32	3274200	3810600	3794400	3664800	3389400
Kingston	G6F-G	54549658	54810000	51342000	50850000	50484000
Narragansett	G32	1224240	1075440	1166640	1251600	1239120
Providence	G32	1074720	1113400	1087800	1077800	1063280
Providence	G32	1005600	1040400	987000	1057800	1084200
W Greenwich	G3F-G	846000	884400	876000	893100	937800
Providence	G3F-G	624000	675200	634720	636280	676920
Peace Dale	G02	334800	346300	382900	402100	375000
Providence	G3F-G	11773571	2283429	0	0	0
Cranston	G3F-G	12848000	12524000	12157600	9326400	8660800
Providence	G3F-G	8398000	8404000	8914000	9352000	7665600
Warwick	G32	1055200	1279200	1292600	1273400	1212200
Westerly	G3F-G	1259575	1307400	754200	16800	0
Westerly	G3F-G	2987764	3054000	3118000	3053000	2915500
Westerly	G3F-G	2320220	2308400	2297600	2398000	2276800
Westerly	G3F-G	1944303	2022300	1996500	2056500	1912500
Westerly	G3F-G	1436000	1577700	1512600	166700	0
Westerly	G02	391680	388960	360560	398080	381132
Providence	G32	6860000	7301600	7500500	7766600	7918500
Warwick	G32	3703000	3861000	3831000	3962000	3979600
Warwick	G32	2439948	2618000	2709000	2683000	2743900
Providence	G02	231440	243600	214880	225280	219280
Providence	G32	5927244	0	0	0	0

Woonsocket	G32	9234037	10906000	11708200	12121200	11788000
Woonsocket	G32	1732800	1917600	1910400	1922400	1936800
Woonsocket	G02	742140	777630	728770	721420	798000
Woonsocket	G02	671930	686700	682640	720860	785610
Woonsocket	G02	593700	605700	614400	615000	669900
Woonsocket	G32	1902000	1979000	2071000	2166000	2189000
Woonsocket	G32	822000	996000	1038600	990600	1044900
Woonsocket	G3F-G	642400	723280	738000	785760	768720

Division Data Request 16-5

Request:

Re: page 5 of 15, line 10, of the testimony of witness Fields. Please provide the basis, including data, studies, analyses, and other documents upon which the Company relies, to support the assertion that "*economic development and energy are becoming increasingly intertwined*."

Response:

Electricity costs, electric reliability and power quality can be important factors in business investment decisions, particularly for energy-intensive manufacturers and in industries that are highly sensitive to power quality disturbances. Also, because electricity delivery networks require such large investments even to maintain service quality – and to provide capacity for growth – the operation and maintenance of the grid in and of itself represents a direct, ongoing economic development stimulus. Those investments provide economic development benefits through their impact on the construction sector and on the attraction, expansion and retention of business customers.

In addition to this fundamental relationship between energy and economic development, the two are becoming increasingly intertwined due to the growth of the "green economy." Over $100-billion of the $787-billion of ARRA funding has been allocated to energy related programs and initiatives, including clean energy generation, modernization of T&D infrastructure through "smart grid" development, and funding for energy efficiency and alternative-fuel vehicle programs. That level of capital investment represents a tremendous economic development impact for the U.S. economy.

In Rhode Island, clean energy and green technology job growth is likewise an extremely high priority for economic development. Governor Donald L. Carcieri, House Speaker William J. Murphy, Senate President M. Teresa Paiva Weed and the Rhode Island Economic Development Corporation (RIEDC) recently hosted a Green Economy Roundtable, which brought together over 125 "green economy" leaders to launch a collaborative effort to promote energy-related job growth in the state.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-6

Request:

Re: page 5 of 15, lines 12-14, of the testimony of witness Fields. Please detail Narragansett Electric's participation in alternative energy development in Rhode Island to date, identifying each project in which the Company is participating and documenting the status of each project.

Response:

The Company currently is not participating in any alternative energy projects in Rhode Island, other than facilitating interconnections for customer-owned projects. The Company currently is more involved in renewable energy activities both within Rhode Island and other jurisdictions. As the rapid emergence of renewable energy technologies continues, National Grid expects opportunities for direct involvement in renewable energy development to increase in Rhode Island as well. The Company's proposed economic development programs could play a role in identifying those opportunities and providing a conduit for customers to capitalize on them.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-7

Request:

Re: page 5 of 15, lines 15-17, of the testimony of witness Fields. Please:

a. Detail all known elements of the "*highly effective, integrated network of state, regional, and local economic-development entities*" to which the witness refers; and

b. Provide the criteria, data, analyses, and studies upon which the Company relies to assess effectiveness of the "*integrated network of state, regional, and local economic-development entities*" that presently serves Rhode Island.

Response:

a. There are a number of professional organizations providing economic development services in Rhode Island. These include the Rhode Island Economic Development Corporation where National Grid is a member of the board, the Economic Development Foundation of Rhode Island and the Rhode Island Small Business Development Center. At the local level, Providence, Cranston, Warwick, Pawtucket and Newport are among the municipalities that are active in economic development. National Grid holds membership in the Pawtucket Foundation, a group that promotes economic development. In addition to the state and local economic development network, there are also several regional economic development groups that provide services within the broader Northeastern/New England region, including the Northeastern Economic Developers Association.

b. The Company has not formally assessed the level of effectiveness and integration of Rhode Island's state, regional and local economic development network. There is no known data or analysis that quantifies economic development effectiveness and integration. The witness' characterization of the economic development network in Rhodes Island as "highly effective and integrated" is based on National Grid's experience and familiarity with economic development organizations and activities nationwide, through membership in the International Economic Development Council, Utility Economic Development Association, Northeastern Economic Developers Association, New York State Economic Development Council and other national, regional, state and local economic development organizations.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-8

Request:

Re: page 6 of 15, lines 5-8, of the testimony of witness Fields. Please:

a. List the "*lessons learned*" through National Grid's economic development experience in all areas of its U.S. operations;

b. List the "*best practices*" that the Company will incorporate in its Rhode Island program; and

a. Provide the criteria, data, analyses and studies upon which the Company has relied to identify the "*best practices*" that the Company will incorporate in its Rhode Island program.

Response:

a. National Grid and its legacy companies have been providing economic development services in New York State for over 75 years, in economic conditions that have ranged from booming growth to deep recession. The Company's New York service territory is extremely diverse in terms of its economy and demography, from extremely dense urban areas such as Brooklyn, to very sparse rural areas in Northern New York. The lessons the Company has learned through this experience include all facets of economic development – working with existing customers to help them become more profitable, marketing the service territory to prospective customers, forming effecting partnerships with state and local development agencies and developing/implementing effective incentive programs. The Company is confident that these "lessons learned" will allow National Grid to deliver valuable economic development programs in its Rhode Island service area.

b. The "best practices" the Company will incorporate in its Rhode Island programs include basic program design (eligibility requirements, funding guidelines), administrative processes (application and approval process, project verification and reimbursement process), and program evaluation.

The Company's economic development programs have been subject to multiple internal and external reviews over the past 7 years, including an internal financial review related to the Sarbanes-Oxley Act of 2002, two reviews by National Grid's Internal Audit department, and an ongoing review by New York DPS Staff. The outcomes of all reviews and audits to date have been favorable, and the programs

Division Data Request 16-8 (cont.)

have incorporated all process and control recommendations made as a result of each review.

The Company's Upstate New York programs, which were developed as part of the National Grid-Niagara Mohawk merger in 2002, were viewed by the New York Public Service Commission as a model for economic development programs at other New York utilities since that time. In short, the Company feels that its existing programs offer a multitude of "best practices" that it can draw from to benefit its Rhode Island service area.

c. In addition to the internal and external "best practice" feedback described in part (b) above, National Grid has also received positive reactions from state/regional/local economic development entities that strongly suggest the Company's programs are among the most innovative and effective utility offerings in the industry. Customer satisfaction with the application and approval process has consistently scored in the 90 percent-plus range, which also indicates that the Company's current program administration processes should be considered "best practices" that are worthy of transferring to Rhode Island.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-9

Request:

Re: page 6 of 15, lines 8-10, of the testimony of witness Fields. Please:

a. Provide detail documentation of each "*energy discount program*" and/or "*price incentive program*" that National Grid presently offers in the State of New York;

b. Provide all information upon which the National Grid relies to assess the results of its energy discount programs and price incentive programs in New York.

c. Provide the data, studies, analyses, and rationales upon which the Company relies to conclude that "energy discount programs" and/or "price incentive programs" are not appropriate for deployment in Rhode Island at this time.

Response:

a. Attachment DIV 16-9-1 through DIV-16-9-4 are tariff sheets for each of the Company's current discount offerings. The Company's Empire Zone Rider (EZR) discount program provides substantial delivery discounts to businesses that locate or expand in a NYS-designated Empire Zone. The program was mandated through New York State legislation and a subsequent NYPSC order in the late 1980s. Similarly, the Company's S.C. 11/12 electric discount program emerged as a requirement from a statewide "competitive opportunities" proceeding in the 1990s, and was developed according to guidelines set by the PSC. In Metro New York, the Company offers Economic Development Gas Rate (EDGAR) discounts, including Business Incentive Rates (BIR) and Area Development Rates (ADR). (see five attachment included herein named: PSC220-Rule 34; PSC220-SC12; Upstate Gas-Rule 22; Downstate-PSC12 Gas leads; Downstate-Edgar.)

b. The Company tracks the discounts (revenue shortfall) associated with these programs. In Upstate NY, the Company also tracks kWh and other energy use data associated with discounted service, in order to comply with various regulatory reporting requirements.

c. Based on the Company's experience administering both grant programs and discount programs in New York, National Grid feels that its proposed economic development grant programs are more appropriate than discount programs for deployment in Rhode Island at this time. Based on Company experience, discount programs can be far more costly than targeted grant programs. During 2008 in Upstate New York alone, the Company's electric discount programs

Division Data Request 16-9 (cont.)

resulted in $23.6 million in rate reductions for participating customers. Discount programs are also typically very complex and costly to develop and implement as compared to targeted grant programs. Particularly as an initial foray into developing economic development programs in Rhode Island, the Company feels that its proposed grant programs are a more cost-effective and appropriate "first step."

Also, energy discounts can provide a disincentive for some customers to pursue energy efficiency measures that might be better for the customer and for society in the long term. In contrast to a standardized term of delivery (only) discounts, the installation of energy efficiency technologies can help customers reduce both energy delivery and energy supply costs -- and those benefits are generally realized over a much longer period than a finite stream of volumetric discounts.

Lastly, the Company's proposed pilot program would provide greater flexibility to address a wide range of economic development opportunities – some directly with customers, and others in cooperation with state and local economic development entities. Energy discount programs are extremely limited in this regard.

As indicated in the response to part (a) above, many of the Company's current discount programs were developed more than 10 years ago, and were developed more in reaction to governmental and regulatory mandates rather than Company strategic objectives. If and when the Company is given an opportunity to alter the "mix" of grant and discount programs available in its New York service areas, the Company would likely seek to eliminate, restructure and/or dramatically reduce the scope of its discount programs in favor of the targeted grant approach.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-10

Request:

Re: page 6 of 15, lines 14-21, of the testimony of witness Fields. Please:

a. Provide the rationales upon which Narragansett Electric relies to classify its proposed Economic Development Program as a "*Pilot Program*" and explain how it would differentiate a pilot program from a non-pilot program;

b. Provide the criteria by which Narragansett Electric will assess the success of its proposed Economic Development Pilot Program for its Rhode Island service territory;

c. Identify the data that the Company intends to use to evaluate the extent to which its criteria for measuring the success of its economic development efforts have been met; and

d. Provide the criteria by which Narragansett Electric will assess the sustainability, or expansion, of its economic development program results in Rhode Island.

Response:

a. National Grid's proposed economic development program is being classified as a "Pilot" initiative because it represents the Company's first comprehensive economic development program proposal in Rhode Island in over 14 years. Prior Company offerings have been limited to providing eligible customers discounts on their bill (please refer to the response to Division Data Request 15-2). The program would be considered a "non-pilot" program if and when the Company receives approval for programs effective in 2011 and beyond.

b. The Company will evaluate the success of its proposed Economic Development Pilot Program in Rhode Island based on the number of projects completed, new capital investment, new and retained jobs, leveraged funds, customer satisfaction among grant recipients, the number of leads and prospects responding to marketing efforts, and other measures that may be identified during the 180-day collaborative process.

c. The Company will evaluate the impact of its proposed economic development pilot programs by tracking the number of projects completed, new capital investment, new and retained jobs, leveraged funds, customer satisfaction among grant recipients, and the number of leads and prospects responding to marketing

Division Data Request 16-10 (cont.)

efforts. The proposed 180-day collaborative program development process may provide additional and/or alternative ways of evaluating the success of the programs, and it will also provide guidance with respect to more specific metrics that will become part of the program evaluation process.

d. In addition to the criteria described in the responses to parts (b) and (c) above, the Company will assess the level of application activity and customer inquiries – versus the amount of available funds – in order to help determine sustainability or expansion of the pilot program. In addition, prevailing and forecasted regional economic conditions will play a role in determining the need to sustain or expand National Grid's program on a going forward basis.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-11

Request:

Re: page 7 of 15, lines 1-2, of the testimony of witness Fields. Please provide the data, analyses, and studies upon which the Company relies to assess the benefits that Narragansett Electric, National Grid, and National Grid's shareholders can expect to derive from its proposed economic development programs over the next five years.

Response:

The Company cannot predict the level of activity it will see from its Economic Development pilot program, but the expected outcome is a stronger regional economy in the form of investment, jobs, urban revitalization, new customers attracted, expanded, retained and a more stable customer base into the future.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-12

Request:

Re: page 7 of 15, lines 9-11, of the testimony of witness Fields. Please explain in more detail the statement that "*the Company's proposed economic development initiatives would create new opportunities to utilize National Grid's industry-leading expertise in energy conservation as an economic development tool.*"

Response:

In the course of conducting economic development services, the Company will be in a good position to identify opportunities for energy efficiency assistance. These energy efficiency and economic development services will help make businesses more profitable by providing them a means to control their energy costs with effective strategies delivered by the Company and will increase the likelihood they will remain and expand in Rhode Island. National Grid has an array of energy efficiency services for new construction and renovations of existing facilities. Services included incentives for a portion of incremental costs, technical assistance, and other services for commercial and industrial customers.

In addition, the Company is widely recognized as an "energy expert" through countless awards from efficiency stakeholders, including most recently, 2008 Partner of the Year from Energy Star; 2009 Leadership in Housing Award from the US Environmental Protection Agency for continued partnership with Energy Star; and the 2002 New England EPA Environmental Merit Award for "Better Way to Save" Company for outstanding efforts in preserving the New England environment.

Division Data Request 16-12

Request:

Re: page 7 of 15, lines 9-11, of the testimony of witness Fields. Please explain in more detail the statement that "*the Company's proposed economic development initiatives would create new opportunities to utilize National Grid's industry-leading expertise in energy conservation as an economic development tool.*"

Response:

In the course of conducting economic development services, the Company will be in a good position to identify opportunities for energy efficiency assistance. These energy efficiency and economic development services will help make businesses more profitable by providing them a means to control their energy costs with effective strategies delivered by the Company and will increase the likelihood they will remain and expand in Rhode Island. National Grid has an array of energy efficiency services for new construction and renovations of existing facilities. Services included incentives for a portion of incremental costs, technical assistance, and other services for commercial and industrial customers.

In addition, the Company is widely recognized as an "energy expert" through countless awards from efficiency stakeholders, including most recently, 2008 Partner of the Year from Energy Star; 2009 Leadership in Housing Award from the US Environmental Protection Agency for continued partnership with Energy Star; and the 2002 New England EPA Environmental Merit Award for "Better Way to Save" Company for outstanding efforts in preserving the New England environment.

Prepared by or under the supervision of: Carmen Fields

<u>Division Data Request 16-13</u>

<u>Request</u>:

Re: page 7 of 15, lines 13-15, of the testimony of witness Fields. Please provide greater detail regarding the Company's proposed "*180-day collaborative program development process*," including but not limited to:

a. When the Company anticipates the work of such a collaborative would commence;

b. Identification of key participants and the commitments, if any, that the Company has obtained from such potential participants to date;

c. When and in what forum the results of the 180-day collaborative process would be provided for Commission review;

d. When the Company would commence implementation of the program(s) developed through the collaborative process;

e. A detailed estimate of the costs of the collaborative process;

f. How the costs of the collaborative would be funded.

<u>Response</u>:

a. The Company anticipates the work of the collaborative would commence March 1, 2010.

b. There have been expressions of interest from some involved with economic development in the region, but no firm commitments.

c. The results of the collaborative process would be submitted for approval by the Commission within 90 days, with proposed effective date for the pilot September 1, 2010.

d. The Company would commence implementation of the programs developed through the collaborative process September 1.

e. The Company has not created a cost budget for the collaborative process at this time.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-13 (cont.)

f. The Company will take responsibility for the costs of its participation in the collaborative process.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-14

Request:

Re: page 7 of 15, lines 13-15, of the testimony of witness Fields. Please identify the programs that the Company is prepared to implement at the conclusion of this proceeding without the aide of a 180-day collaborative process.

Response:

The Company would not be fully prepared to implement any new grant programs without the aid of a collaborative process. Without the collaborative program development process, the Company would need to rely heavily on the specific program designs currently used in Upstate New York, without enough input from key economic development agencies and other stakeholders in Rhode Island. As indicated in the response to Division Data Request 16-13, the Company intends to conduct the bulk of the information gathering and program development within the first 90 days of the 180-day collaborative process, which would allow time for the program proposal to be refined and submitted to the Commission for approval before September 1.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-15

Request:

Re: page 8 of 15, lines 3-6, of the testimony of witness Fields. Please detail the elements of the Company's "*comprehensive 'energy solutions' approach to managing customer and community relationships*."

Response:

The Company's comprehensive energy solutions approach emphasizes four key elements that allow the Company to effectively manage customer and community relationships:

1. Account Management— maintaining positive relationships with key customers, and enhancing our customer's competitive position by through delivery of energy solutions to improve their productivity and profitability

2. Sales—growing the National Grid customer base and the Company's share of our customers' energy portfolio, by promoting new technologies and increasing the penetration of our Energy Efficiency programs, products and services.

3. Community Relations—creating positive community relationships and increasing community awareness of National Grid infrastructure investments and other activities. National Grid has a full time Community Relations specialist dedicated to serving communities in the Company's service area.

4. Economic Development—attracting new businesses into the Rhode Island service area, and helping existing customers remain and grow in the state. The Company's proposed economic development pilot program would play a major role in this key element of the Company's comprehensive Energy Solutions Services Strategy.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-17

Request:

Re: page 9 of 15, lines 1-4, of the testimony of witness Fields. Please:

a. Provide a copy of the document in which the New York State Public Service Commission "approved" the referenced "Annual Report filing;"

b. Explain the import of NYPSC approval of that filing to National Grid and its finances;

c. Provide a complete copy of the next National Grid "Economic Development Plan Annual Report" as soon as it becomes available; and

d. Explain in detail the manner in which National Grid's New York State electric utilities recover the costs of existing economic development programs.

Response:

a. The document in which the New York State Public Service Commission "approved" the referenced Economic Development Plan is provided herewith as Attachment DIV 16-17.

b. The approval of that filing provided a rate allowance of $12.5 million per year in incremental economic development funding, for new program initiatives and/or the expansion of existing initiatives. This "Economic Development Plan" rate allowance was part of a larger Economic Development Fund that also included allowances for the Company's electric rate discount programs. The Economic Development Fund was in turn one component of a larger deferral account that also reconciled revenues and costs from items such as pensions and benefits, environmental remediation, service quality penalties and benefits, environmental remediation, service quality penalties and other cost categories. The deferral account is tied to the Company's rate base, with a mechanism for potential rate adjustments as outlined in the National Grid-Niagara Mohawk Merger Joint Proposal.

   Since 2002, actual spending associated with the Company's Upstate Economic Development Plan programs has totaled $29.3 million.

c. A copy of the Company's next Annual Report will be provided as soon as it is available, after September 1, 2009

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Division Data Request 16-17 (cont.)

d. As described in part "b" above, the costs associated with the Company's economic development programs are recovered from other retail customers. The $12.5 million annual Economic Development Plan allowance is reconciled to actual program expenditures on a monthly basis, and those differences are deferred monthly for later refund to –or collection from—other retail customers in accordance with the applicable provision of the National Grid-Niagara Mohawk Merger Joint Proposal.

Prepared by or under the supervision of: Carmen Fields

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on October 23, 2002

COMMISSIONERS PRESENT:

Maureen O. Helmer, Chairman
Thomas J. Dunleavy
James D. Bennett
Leonard A. Weiss
Neal N. Galvin

CASE 01-M-0075 - Niagara Mohawk Holdings, Inc., Niagara Mohawk Power Corporation, National Grid Group plc, and National Grid USA – Petition for Approval of Merger and Stock Acquisition.

ORDER ADOPTING ECONOMIC DEVELOPMENT PLAN

(Issued and Effective October 24, 2002)

BY THE COMMISSION:

BACKGROUND

Under the Rate Plan Order,[1] Niagara Mohawk Power Corporation (Niagara Mohawk) was directed to propose an Economic Development Plan (ED Plan), after consultation with interested parties. The ED Plan would increase funding for existing programs and develop new program initiatives for encouraging the attraction, expansion and retention of business customers within the utility's service territory. The utility would consider, in drafting its Plan, offering discounts on the delivery of incremental Economic Development Power supplied to qualified business customers by the New York Power Authority (NYPA). The utility was directed to submit, by September 1 of each rate

[1] Case 01-M-0075, supra, Opinion No. 01-6 (issued December 3, 2001), Joint Proposal §1.2.10.

year, an updated ED Plan for the upcoming calendar year, and serve a copy of the update on the Empire State Development Corporation (ESD) and Staff.

After soliciting input from interested parties, Niagara Mohawk filed its proposed ED Plan on June 28, 2002. Several parties commented on the ED Plan by September 3, 2002, within the time prescribed under State Administrative Procedure Act (SAPA) §202(1).

POSITIONS OF THE PARTIES

Niagara Mohawk's Filing

Niagara Mohawk proposes to continue its historic commitment to economic development, while devising and implementing incremental economic development initiatives. The incremental initiatives include energy price incentives, electric infrastructure enhancements, informational and business attraction marketing programs, and energy efficiency programs.

Describing its past commitments to economic development, Niagara Mohawk notes it offers an Economic Development Zone Rider (EDZR) that provides for discounts to customers who locate or expand in an Empire Zone. Currently, 23 Empire Zones lie within the utility's service territory, serving as sites for businesses ranging in size from small retail establishments to large industrial concerns. Under the EDZR tariff, customers receive discounted delivery service, while paying market rates for energy supply.

Niagara Mohawk reports it also offers flex rate contracts that reduce electricity prices to business customers, promoting both the attraction of new businesses and the retention of existing businesses. One feature of the flex rate program is standardized discounts for most qualifying participants, administered through offsets against the utility's

Competitive Transition Charge (CTC). Individually-negotiated pricing plans, however, are permitted under unusual circumstances, to avoid missing economic development opportunities.

Its Economic Development Department, Niagara Mohawk relates, administers a variety of additional initiatives promoting business attraction and expansion. The utility maintains a comprehensive database of available business sites and offers assistance with site tours and presentations for prospective customers. It also markets nationally and internationally the benefits of locating in upstate New York.

Niagara Mohawk would add new initiatives to these existing programs. Under the Small Business Growth Transition (SBGT) initiative, qualifying small business customers growing upward into a higher-consumption rate class may retain the energy demand charges from the lower-consumption rate class for a two-year transition period. Smoothing the transition, the utility asserts, would afford small businesses additional time to prepare for impacts associated with the differences between the higher and lower rate classes.

An electric infrastructure enhancement initiative, Niagara Mohawk relates, would provide a source of funding for utility infrastructure installations or upgrades. Infrastructure investment would be available to fund the electric equipment installations or upgrades needed to convert vacant or under-utilized commercial or industrial buildings into marketable business sites, thereby making them "shovel ready" for development. Through the initiative, funding would also be available for major electric infrastructure projects that create a substantial number of new jobs; for construction of distribution facility upgrades to three-phase service; for assisting customers moving to 60-cycle service; and for electric infrastructure investment at "brown field" sites.

Niagara Mohawk also proposes to conduct informational advertising and otherwise disseminate information on its economic development programs. It would publicize program eligibility criteria and encourage applications, and conduct strategic outreach to attract prospects for direct investment. The utility also promises to engage in a cooperative business attraction program, matching its marketing funds against amounts furnished by other economic development organizations for that purpose.

Another initiative, Niagara Mohawk continues, is energy efficiency programs targeted to businesses, including those located in Empire Zones, and dairy farms, that complement the energy efficiency programs managed by the New York State Energy Research and Development Authority (NYSERDA). The qualifying customers may avail themselves of incentives and grants funding installation of energy-efficient systems that reduce energy use and boost productivity. These programs are intended to mitigate out-of-pocket expenditures by qualifying businesses.

Niagara Mohawk budgets approximately $39 million to fund its ED Plan; $12.5 million in incremental spending would be directed to the new initiatives, with the remainder of the budget supporting the existing EDZR and flex rate contract programs. Additional spending, the utility asserts, is not needed. With the reduction in rates accompanying the Rate Plan Order, the utility claims, many of its existing discount and flex rate contract programs should be allowed to expire, because their prices would exceed the standard tariff prices.

ESD

While expressing its satisfaction with Niagara Mohawk's economic development budget generally, Empire State Development Corporation (ESD) finds the proposed spending inadequate in a few respects. ESD declares that the $0.5 million directed towards economic development outreach and marketing efforts is insufficient. ESD also would focus that spending on business attraction and regional marketing efforts. Moreover, ESD maintains that the utility should be directed to expend the full funding level under the budget, both generally and for each of the annual program-specific funding targets identified in the budget.

ESD also finds the ED Plan inadequate in several respects. ESD contends that the Plan should fund the cost of an exemption from the CTC for the delivery of an additional 20 MW in NYPA-supplied EDP energy. ESD would add another attraction program to the ED Plan, for funding the cost of obtaining permits needed to develop sites and the construction of occupancy-ready facilities.

ESD also asks that spending be monitored more closely. ESD believes additional procedures should be devised to facilitate interested party participation in the evaluation of future changes to the ED Plan and in developing the content of economic development reports.

MI

Multiple Intervenors (MI) asserts that a number of modifications to the ED Plan are needed. According to MI, the ED Plan relies too heavily on new and untested programs, at the expense of existing economic development initiatives that have proven their worth. Fearing that the new programs will not yield the benefits expected, MI would reallocate the $12.5 million in incremental spending to proven programs.

MI is also concerned that the proposed $12.5 million in incremental spending will not actually be expended, because it will be difficult to find worthwhile projects that fit within Niagara Mohawk's new initiatives. MI recommends that any budget spending shortfall be retained within the ED Plan for spending in the subsequent year.

Analyzing Niagara Mohawk's new initiatives further, MI questions several aspects of the utility's electric infrastructure enhancement programs. Describing the "shovel ready" infrastructure funding as speculative spending, MI cautions that infrastructure could be built when there is no commitment from any customer to locate at a site. If the site remains unoccupied after the infrastructure is installed, MI argues, the economic development spending would be unproductive.

MI also asserts that there is the potential for diversion of economic development funds to infrastructure projects that Niagara Mohawk should fund from other sources. Infrastructure development, MI points out, is a traditional utility responsibility and Niagara Mohawk might be able to shift its cost burden for that responsibility to economic development funding. MI urges close supervision of Niagara Mohawk's infrastructure expenditures to ensure that the utility is not double-recovering its costs or charging costs inappropriately to the ED Plan when those costs should be funded out of the utility's general capital improvement budget.

Focusing on economic development spending for the direct benefit of customers, MI supports those Niagara Mohawk infrastructure programs that directly assist customers facing circumstances outside the scope of the utility's traditional economic development programs. MI also supports capital investment grants, directed to customers that could benefit from electric infrastructure improvements.

To facilitate successful implementation of those infrastructure programs, MI recommends an adjustment to the ED Plan. The Plan, MI relates, requires that all funding needed to complete an infrastructure project must be in place before the utility will approve an economic development assistance grant. MI believes the timing of the approval could prove tardy. MI would require the utility to decide earlier if a grant is appropriate, while withholding release of the grant pending completion of funding arrangements. Delaying review of the grant until funding from other sources is first in place, MI complains, could unreasonably delay and frustrate the construction of needed infrastructure.

MI also criticizes the proposed spending on informational and promotional programs. Economic development spending, MI again insists, should be directed primarily to the assistance of customers, and so funding of advertising for informational or promotional purposes should be carefully constrained. Otherwise, MI maintains, economic development funding could be diverted to programs that yield few benefits.

MI sees little economic development impact in the SBGT initiative. The alleged barrier the program addresses, MI asserts, is the increasing per-unit delivery rates encountered by some customers growing into a higher-volume service classification. According to MI, this rate design anomaly runs counter to the well-accepted principle that consumption of a greater volume should not result in increased per-unit costs. MI believes Niagara Mohawk should be required to correct its faulty rate design, rather than relying upon economic development spending to rectify the problem.

Noting that Niagara Mohawk suggests that the ED Plan be evaluated every two years, MI asks that it and other interested parties participate in its development. MI maintains it and other consumers have a legitimate interest in ensuring that Niagara Mohawk properly implements the ED Plan and spends the ED budget. MI suggests procedures for facilitating participation in the evaluation.

NYS EDC

The New York State Economic Development Council (NYS EDC) believes Niagara Mohawk should fund improvements in rural telecommunications infrastructure, including enhanced broadband penetration. NYS EDC argues that improved telecommunications access is a key element to fostering economic development in Niagara Mohawk's service territory.

Senator Wright

Senator James W. Wright agrees that improvements to telecommunications infrastructure are essential to promoting economic development in Niagara Mohawk's service territory. He also urges that more funding be directed towards marketing, including joint marketing initiatives between Niagara Mohawk and local economic development partners. The Senator also supports initiatives for funding the costs of site pre-permitting and occupancy-ready development.

DISCUSSION AND CONCLUSION

Because Niagara Mohawk's ED Plan properly promotes economic development within its service territory, the ED Plan's terms and conditions are adopted, subject to the modifications described below. Moreover, the ED Plan is properly budgeted,[2]

[2] Concerns that Niagara Mohawk might improperly retain funds by under-spending the budget should by allayed by the fact that unspent deviations from budgeted amounts are returned to ratepayers under the Rate Plan Order (Joint Proposal, §1.2.4.7).

with spending appropriately balanced between existing and new economic development initiatives.

The Existing Economic Development Programs

Under the ED Plan, Niagara Mohawk will continue its existing EDZR and flex rate contract programs. The discounts available under these programs accord with our policies on enhancing the economic viability of New York State through electric rate reductions for businesses facing competitive pressures as a result of their electric bills.

While the Rate Plan Order provided for consideration of EDP delivery discounts as a means for promoting economic development, the available incremental funding is better spent on the EDZR and flex rate economic development tools. A flex rate contract in particular can be used to target the maximum potential benefit directly to the needs of a particular business customer, an outcome that cannot be replicated under the less flexible EDP program. ESD's proposal to increase the discounts available to new EDP customers is therefore rejected.

The New Economic Development Initiatives

Niagara Mohawk's new economic development initiatives are properly structured and should adequately foster economic development. The SBGT initiative will assist small customers in growing their businesses.[3]

The electric infrastructure enhancement initiative is an appropriate means for attracting businesses to otherwise-unappealing locations. The ED Plan's enhancements should entice new businesses to consider vacant locations or attract businesses to sites where infrastructure is an obstacle to relocation. Moreover, these infrastructure enhancements, once in place, should increase loads on under-utilized utility

[3] MI's criticisms of the rate design underlying the SBGT are outside the scope of Niagara Mohawk's ED Plan filing.

delivery infrastructure situated between the site-specific enhancements and remote sources of generation. As a result, Niagara Mohawk's electric infrastructure enhancement proposals are adopted, subject to the adjustment that MI proposes to the timing for review and approval of electric infrastructure improvement grants.

MI's proposal -- to withhold release of funds pre-approved under an electric infrastructure grant contingent upon the realization of remaining funding from other sources -- is an improvement to Niagara Mohawk's grant review and authorization process that the utility shall implement. The utility should not, as it proposed, defer approval of a grant application until after other sources of funding become concrete.

The electric infrastructure enhancement programs, however, need not be expanded to encompass other forms of infrastructure spending. Just as we would be reluctant to require telephone customers to fund energy or water infrastructure improvements, we are not inclined to require Niagara Mohawk's customers to fund building site improvements or telecommunications upgrades,[4] as suggested by some of the parties. While these forms of infrastructure spending might promote economic development, payments funded by electric ratepayers are best directed to electricity-related infrastructure costs. Thus, Niagara Mohawk's infrastructure spending should be tied to electric infrastructure needs.

Niagara Mohawk's informational advertising and marketing efforts are properly designed and budgeted under the

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[4] Recently-enacted legislation directs the Department of Public Service to prepare a report on rural telecommunications access, and to make recommendations on the elimination of barriers to access and on incentives that would foster the upgrade of rural telecommunications infrastructure. 2002 Laws of New York Ch. 132 (July 23, 2002).

ED Plan. Proposals to either expand or reduce the funding allocated to this purpose would unreasonably constrain Niagara Mohawk's flexibility to allocate available funds among program elements to the maximum economic development benefit.

Niagara Mohawk's energy efficiency programs are an appropriate approach to economic development. These programs result in lower energy bills for business customers, are consistent with our long-standing policy of encouraging energy conservation and complement similar NYSERDA programs without duplicating them.

Ratemaking, Accountability and Reporting

Some ratemaking, accountability and reporting aspects of the ED Plan need revision. The Rate Plan Order established targets for deferral accounting of economic development expenses, with deferrals calculated at the difference between actual and forecast expenditures. The proposed ED Plan budget deviates somewhat from the forecast expenditures, requiring adjustments to the relevant deferral account. The adjustments are set forth in Appendix A.

While flexibility in implementing the ED Plan maximizes the benefits of economic development spending, adequate accountability also must be ensured. To that end, Niagara Mohawk shall develop guidelines for implementing the new economic development initiatives and criteria for selecting individual projects for funding under the initiatives. Generic guidelines and criteria that the utility should adapt to its particular circumstances are attached as Appendices B and C.[5] MI's concerns about improper utility spending on infrastructure

[5] These requirements will not adhere to the EDZR tariff, because it is a statutory entitlement program, or to flex rate contracts, because existing tariff provisions adequately address selection of participants, accountability and reporting for that program.

development should be adequately addressed through implementation of these guidelines and criteria.

Niagara Mohawk shall submit its proposed guidelines and program selection criteria to the Director of the Office of Consumer Education and Advocacy (OCEA) for review within 30 days of the date of this Order. Moreover, the reporting requirements applicable to the ED Plan are revised, to require Niagara Mohawk to submit an economic development Annual Report on September 1 of each rate year. The Report shall satisfy the economic development guidelines, and shall update the ED Plan for the coming calendar year.

The concerns raised by ESD and MI, including their emphasis on the careful monitoring of spending, can be accommodated through the Annual Report process. Niagara Mohawk is directed to serve a copy of the Report on all interested parties as of the date of its filing. Parties will be afforded an opportunity to comment on the Report, within 30 days of the date of its filing.

The further revisions to the process for the evaluation and implementation of the ED Plan that ESD suggests are not needed. The structuring of the Annual Report requirement described above is sufficient to allow for consideration of any modifications to the ED Plan that might be needed, and properly balances the efficiency attending utility flexibility in program implementation with the need for public participation in the planning process.

The Commission orders:

1. Niagara Mohawk Power Corporation is authorized to disburse the spending on the Economic Development Plan discussed in the body of this Order, and is directed to implement the Plan

subject to the conditions and modifications discussed in the body of this Order.

2. Niagara Mohawk Power Corporation shall submit, to the Director of the Office of Consumer Education and Advocacy, economic development plan program guidelines and project selection criteria for review within 30 days of the date of this Order, in conformance with the discussion in the body of this Order.

3. Niagara Mohawk Power Corporation shall submit an Annual Report on the Economic Development Plan to the Director of the Office of Consumer Education and Advocacy within 60 days of the end of each year of the Plan. Copies of the Annual Report shall be served on all active parties to this proceeding, and parties may file with the Secretary an original and five copies of comments on the Report within 30 days of its service.

4. This proceeding is continued.

By the Commission,

(SIGNED) JANET HAND DEIXLER
Secretary

Deferral of Economic Development Plan Costs

As of the date of this Order, Niagara Mohawk shall begin including in the Rate Plan Order deferral account the economic development costs for programs approved in this Order. To properly match economic development plan rate allowances with the deferral accounting prescribed under the Rate Plan Order, it is necessary to increase the deferral targets by the amount built into base rates for external economic development plan expenses (e.g., non-utility labor and labor-related costs). Therefore, for the years 2002 – 2011 the base amounts approved for economic development plan costs contained in Attachment 15 in Case 01-M-0075 shall be increased by the following annual amounts:

2002	$851,000
2003	$832,000
2004	$814,000
2005	$797,000
2006	$816,000
2007	$836,000
2008	$856,000
2009	$875,000
2010	$895,000
2011	$916,000

GENERIC PROGRAM GUIDELINES FOR ECONOMIC DEVELOPMENT GRANTS AND AWARDS

I. APPLICATION

1. All applicants that apply for funding (including second, third, and fourth parties), must identify the overall program category under which they are applying:

   a. Attraction – economic incentives offered to relocate into the utility's service territory;
   b. Retention – economic incentives offered to encourage business retention; includes reduction of substation costs that would lead to job retention;
   c. Expansion – supports growth opportunities;
   d. Utility Facilities – increases utilization of existing utility facilities without significant additional investment; and
   e. Marketing – informational advertising that may be effective in conjunction with regional advertising.

2. A funding candidate shall submit to the company for its review documentation demonstrating that its proposed project or performance satisfies the project selection criteria attached as Appendix C.

3. All applicants shall provide the proposed amount requested, a supporting budget, and an estimated expenditure timeline with milestones showing how and when funds will be expended.

II. REVIEW/SELECTION

1. The company is ultimately responsible for decisions to award funds.

2. The company shall review and evaluate applications, by program category, based on the project selection criteria.

3. To implement selection flexibly, the company shall review applications in accordance with the project selection criteria and evaluate applications based on the overall goal of furthering the objective of any of the following program categories: Attraction, Retention, Expansion, Utility Facilities, and Marketing.

4. The company shall maintain the supporting documentation justifying its reasoning for approval or rejection of each proposed project. Each award shall be supported by a work order that accurately reflects the funding the company supplies.

III. REPORTING/EVALUATION REQUIREMENTS

1. A review and evaluation of each funding allowance shall be performed according to the criteria described in the application.

2. Funding recipients shall file a semi-annual progress report with the company after receipt of an award and a final report when the project is completed. The report shall describe, by program category, the recipient's expenditures and the economic activity criteria it achieved or made progress toward. The report shall compare the recipient's progress to the criteria proposed in its application. The recipient shall maintain supporting documentation (i.e., expense vouchers) for company review. The company shall review each report and make a recommendation, if applicable, on whether funding should be continued.

3. The company shall review and evaluate the reports received from each recipient for that program year and provide a description of each funding award by program category. The company shall include this information in the Annual Report to be filed with the Director of the Office of Consumer Education and Advocacy within 60 days after the end of each program year. The company's Report shall state the basis for each award, the amount awarded, achievements, and the basis for making the award, and compare the actual amounts expended to the achievements or progress made.

4. When funding regional advertising, for the program category of "Marketing," the company shall list matching funds from other regional agencies.

IV. PROJECT CANCELLATION

1. Any recipient that fails to fulfill the reporting and evaluation requirements described in Section III may be subject to the loss of its grant or award and may be prohibited from applying for additional funding, pending review of its performance.

2. Any recipient that uses funds in a manner not described in its application, as approved, is subject to suspension of its funding and may be prohibited from applying for future funding, pending review of its performance.

3. A recipient of a multi-year award shall demonstrate in its semi-annual report that it achieved performance standards or milestones before further funds will be provided.

CASE 01-M-0075 **APPENDIX C**

Economic Development Plan
Proposed Selection Criteria Summary

Programs:	I Attraction Program (a)	II Retention Program	III Expansion Program	IV Utility Facilities	V Advertising
Selection criteria:					
capital invested	X		X		
number of jobs at risk		X			
number of new or potential new jobs	X	X	X	X	
incremental utility revenue				X	
must expand or relocate				X	
VIII Additional Program Criteria					
number of jobs	X	X	X	X	X
capital investment	X	X	X	X	X
new/improved construction (sq ft.)	X		X		X
energy efficiency (kWh,therms, peak load)			X		
no. new expansion/attraction projects CHGE territory	X		X	X	X
no. of attraction leads	X				X
other development leveraged	X		X	X	
financial condition	X		X	X	
management experience	X		X	X	
credit references	X		X	X	
amount of entity's contribution	X		X	X	
amount of financing leverage	X		X	X	
incremental utility revenue	X	X		X	X
benefits to other utility customers	X	X		X	X

Division Data Request 16-18

Request:

Re: page 9 of 15, lines 10-12, of the testimony of witness Fields. Please:

a. Identify all instances presently known to the Company where infrastructure issues in its Rhode Island service territory present barriers to the growth or retention of a customer's business;

b. Note when the Company first became aware of each infrastructure issue identified in the response to part a. of this request; and

c. Explain the steps that the Company has taken to date to alleviate those infrastructure related problems.

Response:

a. The Company has not compiled a list of current issues involving customers whose electric delivery infrastructure presents a barrier to their growth and retention. The specific customer growth and retention projects that may be funded through the Company's proposed pilot initiatives are most likely not presently known to the Company, because they do not yet exist. The types of customer projects that may be funded through the proposed pilot initiative are not typically long term and lingering in nature. The opportunities tend to arise and be resolved (or not) within a span of 6 months or less. Most current growth opportunities and retention issues will not still exist at the time of program implementation—they will most likely have come and gone, and the outcome could very well be a missed growth opportunity to even the loss of an existing National Grid customer. As we are at least eight months from potential program implementation, it would not be particularly useful to compile a list of currently existing growth opportunities and retention issues.

   In the coming months, and also as part of the proposed 180-day collaborative process, the Company will begin to collect information internally (from key account executives and others) and externally (from economic development service providers) to identify existing and emerging customer issues that may still be "open" at the time of program implementation.

b. See response to part (a) above. The Company has not compiled a list of current customer infrastructure issues.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-18 (cont'd)

c. See response to part (a) above. The Company has not compiled a list of current customer infrastructure issues.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-19

Request:

Re: page 10 of 15, lines 11-12, of the testimony of witness Fields. Please list the "*key industrial sites and buildings*" in Company's Rhode Island service territory that Narragansett has identified to date.

Response:

The Company has not yet identified a list of "key industrial sites and buildings" in the Rhode Island service territory. This exercise will be completed as part of the proposed 180-day collaborative program development process. In the meantime, National Grid economic development staff is gathering sites and buildings information on an informal basis from economic development contacts in Rhode Island and the greater New England region.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-20

Request:

Re: page 11 of 15, lines 3-4, of the testimony of witness Fields. Please define the phrase "*shovel ready infrastructure*" as it is used in the referenced portion of the witnesses testimony and provide the criteria that the Company intends to use to assess whether a project involves "*shovel-ready infrastructure*."

Response:

In this particular context, the term "shovel ready infrastructure" refers to energy delivery infrastructure that is installed "prospectively" at a commercial/industrial site, to make that site more marketable and attractive to businesses looking for a location to build a new facility. Many businesses have extremely short timelines to make a location decision, go through the necessary permitting processes, build out the infrastructure at the site, and actually construct the facility. Any permitting or infrastructure work that can be "pre-completed," including utility infrastructure, can greatly improve the odds that a site will be seriously considered by potential investors.

Specific program details will be developed as part of the proposed 180-day collaborative process. However, the criteria the Company will most likely propose that a definition of a "shovel ready infrastructure" project include:

1) The eligible site must be identified by state and/or local economic development authorities as a key site with strong development potential for manufacturing, R&D or other high value-added uses. The program would not be intended to promote residential, retail or tourism-related development.
2) The site must be located within National Grid's Rhode Island service area;
3) The applicant must either be the owner of the site or a public or not-for-profit economic development agency responsible for development of the site.
4) The site must lack the necessary utility electric infrastructure to make it attractive to potential investors in the targeted industries.
5) Preference will be given to sites which have undergone pre-permitting, are eligible for expedited permitting, or which can otherwise be demonstrated to be the focus of state/local "shovel readiness" efforts.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-21

Request:

Re: page 11 of 15, lines 20-22, of the testimony of witness Fields. Please:

a. List the "*vacant or underutilized structures*" in Company's Rhode Island service territory that Narragansett has identified to date that have "*both strong development potential and idle utility infrastructure*;"

b. Provide the criteria that the Company uses to assess the strength of development potential for "*vacant or underutilized structures in urban areas*;"

c. Provide a detailed listing of all utility infrastructure in the Company's Rhode Island service territory that is known to be idle;

d. Indicate the manner in which "*idle utility infrastructure*" is recognized in the Company's books and records;

e. Identify all "*idle utility infrastructure*" for which costs are included in the Company's requested rate base and quantify the net book value of all such "*idle utility infrastructure*."

Response:

a. The Company has not yet compiled a list of vacant or underutilized structures in its Rhode Island service territory. The Company expects to begin working to identify specific buildings with these characteristics in the coming months, and as part of the proposed 180-day collaborative program development process.

b. The specific criteria that would be employed in a Rhode Island urban revitalization program will be developed as part of the proposed 180-day collaborative process. However, based on its existing programs in Upstate New York, the Company would likely propose the following criteria to assess the strength of development potential for vacant/underutilized structures:

(1) The project must have the support/sponsorship of a municipal or not-for-profit development corporation that is undertaking the project as part of a larger effort to revitalize a central business district or critical commercial corridor. The municipality or not-for-profit entity would be the grant applicant;

Division Data Request 16-21 (cont'd)

(2) The project should demonstrate the ability to create jobs;

(3) The project should demonstrate that it will stimulate other public and private investments within the commercial district; and

(4) The grant applicant should demonstrate that it has obtained commitments from other public funding sources to support the project.

c. The reference to "idle infrastructure" is not a reference to Company-owned infrastructure that is part of the Company's distribution system. It is a reference to *customer-owned* service equipment that is not being used because the facility that would take service is vacant. The service to the building is "idle" to the extent that the structure is vacant and not generating the usage/revenue that would be beneficial to all customers in a ratemaking setting.

d. Please see the response to item (c), above. The reference is to customer-owned equipment, not equipment owned by the Company.

e. Please see the response to item (c), above. There is no cost to the Company. There is only the lost benefit of additional customer revenues that would reduce costs for all customers in the ratemaking setting.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-22

Request:

Re: page 12 of 15, lines 6-8, of the testimony of witness Fields. Please list the municipalities, authorized development corporations, and 501 (c) 3 or 501 (c) 6 corporations that the Company has identified as potential participants in its Rhode Island Urban Revitalization Program.

Response:

The Company has not yet identified a complete list of potentially eligible applicants for "Urban Revitalization Program." The Company plans to become more familiar with the universe of potential projects and grant applicants over the next several months, and as part of the proposed 180-day collaborative process.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-23

Request:

Re: page 12 of 15, line 21, through page 13 of 15, line 6, of the testimony of witness Fields. Please:

a. Document the "*Recent business development activities in Rhode Island that have focused on the life sciences*;"

b. Detail the specific measures that National Grid plans to take to become a "*key partner*" in Rhode Island's efforts to become a "*nation leader"* in the renewable energy and life sciences sectors.

Response:

a. The life sciences industry, which includes biotechnology, pharmaceutical manufacturing, medical device/equipment manufacturing and other sectors, is a major focus of economic development efforts in Rhode Island. Attachment DIV 16-23 is a small sampling of recent announcements and events that illustrate the Rhode Island's strong focus on this industry sector.

b. The Company expects that, as part of the proposed collaborative program development process, the Company will learn about Rhode Island's economic development strategies related to these two industry sectors – and potentially other advanced manufacturing and R&D sectors that represent the state's best economic development opportunities. Although the specifics are yet to be determined, one way the Company may become a key partner is by supporting and participating in key regional, national and/or international marketing and sales initiatives aimed at these industry sectors. The goal of those initiatives would be to promote Rhode Island as the "location of choice" for growing companies in these industries, with the primary objective being new investment and new jobs in Rhode Island. The Company's proposed "Strategic Business Development" initiatives could provide resources to support those efforts.

Another potential role for National Grid in making the state a national leader in these industries is to help identify the available sites and buildings in Rhode Island that represent the best locations for companies in these industries. The Company's proposed "Targeted Infrastructure Improvement" program could be utilized to better prepare those sites to be marketed to companies in those industries.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-23 (cont'd)

Lastly, the Company's proposed pilot initiative may include programs that can help resolve specific customer (or prospective customer) issues in instances where the existing energy infrastructure or capacity are a barrier to that customer locating or expanding in Rhode Island. That assistance would also be provided under the umbrella of "Targeted Infrastructure Improvement."

Again, the proposed collaborative process will be instrumental in developing the specific program initiatives that will best position Rhode Island to succeed in its efforts to become a national leader in these and other strategic industry sectors.

Rhode Island to be Represented at 2009 BIO International Convention

April 15, 2009 | Print this page | Share This |

The Tech Collective, Rhode Island's Information Technology and Bioscience Industry Association, will be partnering with the New England Biotech Association (NEBA) to represent the state's Bioscience industry at the 2009 BIO International Convention on May 17-21, 2009 in Atlanta, GA. Tech Collective is calling for industry companies and agencies who are interested in attending the event or submitting materials for display.

The 2009 BIO International Convention is expected to attract more than 20,000 bioscience professionals from the industry's pharmaceutical, research and development, medical device and diagnostics, environmental and agricultural fields across 48 states and over 60 countries. Currently, the Tech Collective is seeking to collect news, informational and promotional materials from RI's Bioscience Community to display and showcase in Atlanta. This exhibition opportunity is at no cost to Tech Collective member companies.

"We have a diverse, robust and opportunistic Biosciences industry here in Rhode Island," said Kathie Shields, executive director of the Tech Collective, "the 2009 BIO International Convention is an ideal opportunity to showcase that among hundreds of other 21st Century Bio companies and organizations. Unfortunately, tightening budgets combined with the already limited availability and funding of our Bioscience companies can make it difficult to attend this event. Tech Collective encourages, any RI Bio company of any size or focus to contact me directly and we will be sure your company has a place at the Convention in May."

This is the second time in Rhode Island's history that is has been present at this industry-leading event. The first was in 2007, when the Convention was held in Boston, and the Tech Collective, which is the state's BIO affiliate partner, organized RI's pavilion. More than 15 Rhode Island companies, two higher educational institutions and 3 state organizations were represented at the pavilion, which also welcomed several distinguished guests including Governor Donald L. Carcieri, Lt. Governor Elizabeth H. Roberts and Providence Mayor David N. Cicilline.

The Convention will additionally debut the annual BioWorld Expansion and Relocation Guide, which will showcase Rhode Island as one of the top ten "Bio Hotspots" in the United States for the third year in a row. Rhode Island's Bioscience industry employs more than 4,700 people within the state and generates an estimated $526 million in direct and "multiplier effect" revenues, according to BIO.

For more information on Rhode Island's presence at the 2009 Bio International Convention and to get involved, contact Kathie Shields at (401) 521-7805 x105 / email kshields at tech-collective dot org. The deadline for submissions is May 4, 2009.

About BIO
BIO is the world's largest biotechnology organization, providing advocacy, business development and communications services for more than 1,200 members worldwide. Our mission is to be the champion of biotechnology and the advocate for our member organizations—both large and small. BIO members are involved in the research and development of innovative healthcare, agricultural, industrial and environmental biotechnology technologies. Corporate members range from entrepreneurial companies developing a first product to Fortune 100 multinationals. We also represent state and regional biotech associations, service providers to the industry and academic centers. Visit http://www.bio.org/ for more information.

About NEBA
Formed in November of 2008, NEBA is non-profit, member driven organization representing over 600 members from all six New England states and comprised of state biotech associations, biotechnology and biopharmaceutical companies, academic institutions, and other organizations with a collective mission to support and grow the biotechnology industry in New England. As the regional policy and public affairs voice for the biotechnology and biopharmaceutical industry in New England, NEBA is committed to educating policy makers and the public about the biotech industry; promoting public policies that foster innovation; encouraging economic development in the biotech sector; and advocating continued patient access to life-saving and life-improving breakthrough biotechnology medicines. For more information about NEBA, visit http://www.newenglandbiotech.org/

About Tech Collective
Tech Collective is the technology industry association of Rhode Island. Focusing on Community Building and Workforce Development, we are driving technology growth, innovation and prosperity by uniting industry, government and education. Tech Collective builds and strengthens community by creating partnerships, offering thought-provoking forums and organizing state-wide participation in events like Forward Thinking, BioTuesday, Bio Ed, GRRL Tech and Technology Laureate's Night. In promoting and developing a highly-skilled Rhode Island workforce, Tech Collective drives technology-based education and training programs for students in grades K-16 as

well as for incumbent and transitioning workers. For more information about Tech Collective initiatives and events, please visit http://www.tech-collective.org/

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Rhode Island Dubbed "Biotech Hub" in BioWorld Report

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June 10, 2009 | Print this page | Share This |

BioWorld's Summer 2009 Expansion and Relocation report has named Rhode Island one of the top six biotech hotspots in North America. The report called Rhode Island a "small state with a big appetite for biotech and a large menu of agendas to attract bio-entities into its borders."

The report also noted the state's competitive R&D credits and economic development initiatives, such as the Rhode Island Science and Technology Advisory Council, that encourage growth in the life sciences industry. The state's central location in the Northeast's I-95 corridor as well as its small size (which, the report notes, encourages the collaborative nature of the state) added to Rhode Island's biotech appeal.

The 2009 guide marks the third consecutive year Rhode Island has been included as one of the top biotech spots in North America. Joining Rhode Island in the report were Florida, Washington D.C., Georgia, Pennsylvania and Edmonton, Alberta, Canada locations.

The BioWorld report is a showcase of leading Bioscience-friendly locations for business relocation and expansion. Locations are ranked on criteria including site selection, tax credits, location and incubator, funding and research opportunities.

www.bioworld.com/img/BioWorldRelocationGuide2009.pdf

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URI Opens Center for Biotechnology and Life Sciences

Related Media Coverage and Links

- URI Wins $13-Million Federal Grant for Vaccine Research (Providence Journal)
- URI's De Groot wins $13M NIH Grant (Providence Business News)
- URI Awarded $13 Million Grant to Develop Vaccines for Emerging Infectious Diseases (URI Press Release)
- URI opens Center for Biotechnology and Life Sciences (URI Press Release)
- All Together Now: 1, 2, 3 … cut (Providence Business News)
- URI Opens New Biotech Center (WPRI)
- New URI Biotech Center is a Facility Like no Other in the Area (The Providence Journal)

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The University of Rhode Island officially opened the doors today to the Center for Biotechnology and Life Sciences, the largest classroom and research building project in its history, with a grand celebration attended by numerous public officials, industry executives, and hundreds of URI faculty, staff and students.

The 140,000 square-foot facility houses modern teaching laboratories, cutting edge research laboratories, high-tech facilities for DNA sequencing and analysis, faculty offices, a 100-seat classroom, and a two-story, 300-seat auditorium, all to meet the needs of URI's growing environmental biotechnology, life and health sciences programs.

“Today we are opening a new chapter in URI’s ongoing success story as a leading research institution,” said Governor Donald L. Carcieri. “This $54 million, state-of-the-art facility will not only advance scientific research in a host of important areas, but it will also serve as a hub for training, research and job creation in the life sciences. Without question, this high-tech Center will contribute to our ongoing efforts to build an innovation economy. Whether it was providing funding for the planning and design of this academic facility in my budget five years ago or whether it was supporting the bond for the Center for Biotechnology and Life Sciences on the 2004 ballot, I have long been a proponent of this project. “

“This building will serve our students, our faculty, and the growing biotechnology sector here at the University of Rhode Island,” said URI President Robert L. Carothers. “It has been designed to create a learning environment that will allow students to become leaders in these emerging disciplines, while also creating a research environment in which our faculty can make discoveries and transmit new knowledge to the scientific community and to entrepreneurs.”

The Center features a dramatic four-story atrium that connects the research wing with the teaching wing, a rooftop patio, an open stairway that suggests the DNA double-helix, and interior spaces designed to encourage interaction among faculty and students. It also includes numerous design elements that will qualify it for LEED (Leadership in Energy and Environmental Design) Silver certification, just the second new construction project in the state to achieve the designation. The first was URI’s Hope Commons dining hall in 2008.

“This stunning building and the faculty and students it houses will be an important engine of economic development in the state's biotechnology sector for many years to come,” said Jeff Seemann, URI dean of the College of the Environment and Life Sciences. “Its opening is a critically important step forward in Rhode Island’s economic recovery. The research and education that occurs in this building will fuel economic growth and workforce development in biotechnology, health and life sciences, and it will play a key role in driving the state’s new innovation-based economy.”

The Center for Biotechnology and Life Sciences is the anchor of the new North District of the Kingston Campus, which will also be the future home of new buildings for the University’s pharmacy, nursing and chemistry programs. A 113-acre technology park will be located on the opposite side of Flagg Road.

“The development of the North District will make URI a national leader in the life and health sciences and even more central to the economic development of Rhode Island,” said Robert Weygand, URI vice president for administration and finance. “It will increase opportunities for collaboration among faculty and help to create and maintain new relationships with corporate partners and other research and development institutions around the region.”

The architect for the Center was Payette Associates of Boston, and Providence-based Gilbane Building Co. served as the construction manager. The building was funded with a $50 million state bond approved by voters in 2004 and additional corporate, private and federal funds, including $1 million donated by Amgen. Total project costs were $54 million.

Notable sustainable design features include a ‘green’ roof that is partially covered in vegetation that will serve to filter pollutants and reduce heating and cooling needs; a rain garden and storm water treatment feature with a sophisticated drainage and detention system; daylight harvesting technologies to brighten rooms and warm the floors; an energy efficient heating and cooling system; and environmentally friendly framing and interior finish wood.

Another highlight is the aquarium lab, where fish and other marine life used in marine sciences research can be observed behind imposing glass windows. A student affairs office on the first level serves as a resource for students seeking advising, counseling, internships and other services. The fourth floor, which will contain administrative offices and additional laboratory space, will be fit-out at a later date as funds become available.

In addition to five classrooms and 14 teaching laboratories, the Center houses about 30 faculty members and their research groups. These scientists are working in such diverse fields as vaccine development, disease prevention, marine genomics, developmental and sensory biology, animal health and biofuels.

“Bringing biologists together in one building will facilitate great interactions among our faculty and among our students in a way that has not been possible before,” said Jacqueline Webb, professor of biological sciences. “The new teaching labs and auditoriums will significantly enhance our instructional capabilities in both classroom and laboratory settings. I know for a fact that the students are really looking forward to being able to take advantage of what this new building has to offer.”

Added U.S. Senator Jack Reed, who helped to secure $2.8 million in federal funding for the project: “This building brings together under one roof key elements of what URI does best. From pioneering research on Lyme disease, to developing the next generation of clean biofuels, to researching the health of Narragansett Bay, the University of Rhode Island is enhancing its position as a leader in higher learning and innovative research.”

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Division Data Request 16-24

Request:

Re: page 14 of 15, of the testimony of witness Fields. Please:

a. Indicate whether the requested pre-approval of each year's Economic Development Pilot programs would limit the ability of the Division or other parties to subsequently challenge the prudence of expenditures actually made for a year for which pre-approval has been granted;

b. Indicate the basis upon which the Commission would grant pre-approval of economic development initiatives in this proceeding when the specifics of the programs to be implemented are yet to be developed;

c. Indicate whether the "evaluation of previous year's Pilot activities would include:

   i. Assessment of the impacts of the program on the Company's numbers of customers and kWh deliveries;

   ii. Quantification of the success of the program in terms of reducing idle or under-utilized utility infrastructure;

d. Provide the criteria that Narragansett would use to determine when continued funding of economic development programs is no longer necessary or appropriate.

Response:

a. The pre-approval of each year's Economic Development Pilot programs should not limit the ability of the Division or other parties to subsequently challenge the prudence of expenditures made in any year for which pre-approval has been granted. The annual filing and pre-approval is intended to provide a mechanism for the Company to revise its programs, to remove programs, or to create new programs in response to emerging opportunities/issues, changing market conditions or other factors.

b. The Company is seeking approval for a total funding allowance of $1.0 million per year, to be distributed among the three general program categories outlined in the testimony of witness Fields. All other details related to specific program eligibility requirements and funding guidelines will be developed as part of the proposed 180-day collaborative program development process. The outcome of that process will be a more detailed program proposal that would be submitted to

Division Data Request 16-24 (cont.)

the Commission for approval before the end of the 180-day period. In other words, approval is being sought now for the funding allocation and broad program structure – but the Commission and other parties will have a subsequent opportunity to review the detailed program structure before it is implemented by the Company.

c.

(i) The annual evaluation will include a summary of the specific projects that are completed each year, but the emphasis will likely be on the economic impact of the projects (capital investment, new/retained jobs and other common economic development measures) rather than on utility measures such as kW and kWh. Those analyses can be conducted on an "ad hoc basis" as necessary to determine energy use impacts. However, the evaluation will certainly include the number of projects completed, which will facilitate assessment of the number of customers attracted or retained.

As indicated in the testimony of witness Fields, as part of the proposed 180-day collaborative program development process, the Company will work with interested parties to identify appropriate evaluation criteria.

(ii) The evaluation will include a summary of the specific projects that are completed in each year, for each program. To the extent some of those projects result in the re-use of vacant buildings, the redevelopment of "brownfield" industrial sites, or the revitalization of urban neighborhoods, the impact on reducing idle or under-utilized utility infrastructure will be noted and the impacts quantified to the extent possible. Again, as part of the proposed 180-day collaborative program development process the Company will work with interested parties to identify appropriate evaluation criteria, including "sustainable development."

e. In addition to the annual evaluation process, which will provide insight into program benefits versus costs, the Company will monitor program demand (the level of customer inquiries, applications submitted and completed projects) to help gauge the necessity and appropriateness of funding the programs. Monitoring of the prevailing and forecasted regional economic conditions also will provide insight into the need for and appropriateness of the Company's economic development programs. Lastly, the Company will consult with Commission staff and key Rhode Island economic development agencies on an ongoing basis to determine if/when the programs are no longer necessary or appropriate.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-25

Request:

Re: NG-CF-1, page 11of 71, states, "job creation/retention performance generally is not an eligibility requirement for National Grid EDP programs." Please indicate if that statement would apply to the programs that National Grid proposes for Rhode Island, and if so, explain why it is necessary and appropriate.

Response:

Although detailed program descriptions and eligibility requirements will not be finalized until after the proposed 180-day collaborative process, it is likely that this statement will also apply to the programs National Grid is proposing for Rhode Island.

Job creation and retention are expected, desired outcomes of the Company's proposed economic development initiatives, and the Company will attempt to track that information in the best manner possible. However, requiring a specific job COMMITMENT as part of a grant application can be problematic for a number of reasons. For example, such a requirement could be very difficult to develop and enforce for certain programs, such as the proposed "Strategic Business Development" initiatives. That program aims to support marketing and sales efforts that will generate economic growth, but the actual job creation impacts may take several years to occur. Similarly a "Targeted Infrastructure" project might involve infrastructure improvements that help make a site more "shovel-ready" and therefore more marketable—but there can be a long lag between project completion (infrastructure construction) and its ultimate success in creating new jobs and investment.

Furthermore, successful economic development projects may not create new jobs, and in fact may result in an employment decrease. This is because businesses often make capital investments in equipment that will improve productivity—with the desired outcome being less labor content per unit of output. However, increasing the efficiency of an operation will have the benefit of helping to sustain economic activity in the state of Rhode Island. An up-front job commitment could prevent some excellent customer projects from qualifying for assistance.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 16-26

Request:

Please provide a copy of National Grid's most recent annual report for its New York City metro area economic development program. If no annual report has been filed to date, please provide a copy of the first report as soon as it becomes available.

Response:

To date, the Company has not filed an annual report with the New York State Public Service Commission for its NYC metro programs. National Grid does not maintain a comparable portfolio of economic development grant programs in that area, and the Company is not currently required to produce and file such a report. Although it is not anticipated in the near future, the Company will provide a copy of the first annual report if and when it is filed.

Prepared by or under the supervision of: Carmen Fields

Division Data Request 18-1

1. Please rerun the Company's Allocated Cost of Service Study ("ACOSS") with the following changes:

    a. Allocate "Line Transformers" (Account 368) and "Maintenance of Line Transformers" (Account 595) using the following allocation vector:

Residential	54.65%
Small C&I	10.44%
General C&I	21.02%
200 kW Demand	10.72%
3,000 kW Demand	3.17%
Lighting	0.00%
Propulsion	0.00%
Total Jurisdiction	100.00%

    For the purpose of this analysis, please classify Line Transformer plant and Maintenance of Line Transformers O&M expense as "Demand Primary."

    b. Allocate "Uncollectible Accounts-Delivery" (Account 904) costs of $4.301 million on "Total_Del_Rev" allocation factor, which is shown on line 20 of page 2 of Schedule NG-HSG-2.

Response:

Please see Attachment DIV 18-1.

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

Narragansett Electric Company
Rate Year Ended December 31, 2010
Class Cost of Service Study ($000s)
INDEX

Class Cost of Service Study ($000s)
SUMMARY OF RESULTS

		Total	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
			A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
	Revenue at Present Rates								
1	Distribution charge revenue	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
2	Other revenue	7,822	4,665	749	1,134	938	173	149	14
3	**Total Revenue**	223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
4									
5	**Operating Expenses**								
6	Operating Expenses	147,587	79,494	14,647	21,389	18,857	5,140	7,575	485
7	Depreciation Expense	41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
8	General Taxes	23,971	12,173	2,293	3,930	3,255	939	1,287	94
9	**Operating Expenses**	213,024	112,544	20,843	32,238	27,863	7,753	11,035	748
10									
11	Income Before Tax	10,218	5,225	3,143	603	6,332	(2,500)	(2,052)	(533)
12	Income Tax Expense (Benefit)	(3,686)	(1,869)	(341)	(608)	(510)	(149)	(194)	(15)
13									
14	**Net Operating Income**	13,904	7,094	3,484	1,211	6,842	(2,352)	(1,857)	(518)
15									
16	Rate Base	623,946	316,703	57,633	102,769	86,285	25,134	32,896	2,526
17									
18	Rate of Return at Current Rates	2.23%	2.24%	6.04%	1.18%	7.93%	(9.36%)	(5.65%)	(20.50%)
19	Relative Rate of Return	1.00	1.01	2.71	0.53	3.56	(4.20)	(2.53)	(9.20)
20									
21	**Distribution Revenue Requirement**								
22	Distribution charge revenue	280,242	145,981	27,024	43,460	37,298	10,602	14,840	1,037
23	Additional M01 revenue	37	19	4	6	5	1	1	0
24	Forfeited discounts	2,901	2,279	221	227	174	0	1	0
25	Other revenue	5,592	2,913	579	960	804	173	148	14
26		288,772	151,192	27,828	44,652	38,282	10,776	14,991	1,052
27									
28	Operating Expenses	213,024	112,544	20,843	32,238	27,863	7,753	11,035	748
29	Additional uncollectibles expense	719	565	55	56	43	0	0	0
30	Income Before Tax	75,029	38,083	6,930	12,358	10,376	3,022	3,956	304
31	Income Tax Expense	18,999	9,644	1,755	3,129	2,627	765	1,002	77
32	**Net Operating Income**	56,030	28,440	5,175	9,229	7,748	2,257	2,954	227
33	Rate of Return	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%
34									
35	Increase (Decrease) Required $	65,530	33,423	3,843	11,811	4,087	5,523	6,008	837
36	Increase (Decrease) Required %	29.4%	28.4%	16.0%	36.0%	12.0%	105.1%	66.9%	388.5%

Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	**I. ELECTRIC PLANT IN SERVICE**									
2	**A. PRODUCTION PLANT**									
3	Production Plant		3,127	1,261	229	569	806	223	28	10
4	Subtotal - PRODUCTION PLANT	350-359	3,127	1,261	229	569	806	223	28	10
5										
6	**B. DISTRIBUTION PLANT**									
7	Land and Land Rights	360	9,586	4,315	825	1,669	2,025	598	87	68
8	Structures and Improvements	361	7,196	3,239	619	1,253	1,520	449	65	51
9	Station Equipment	362	171,209	77,067	14,728	29,811	36,159	10,685	1,551	1,208
10	Poles, Towers and Fixtures	364	185,255	95,670	18,283	36,847	24,478	7,234	1,926	818
11	Overhead Conductors and Devices	365	265,515	130,998	25,034	50,522	42,383	12,525	2,637	1,416
12	Underground Conduit	366	62,534	29,588	5,654	11,426	11,491	3,396	596	384
13	Underground Conductors & Devices	367	135,960	63,429	12,121	24,506	26,056	7,700	1,277	871
14	Line Transformers	368	160,299	87,603	16,735	33,695	17,184	5,081	0	0
15	Services	369	72,382	62,666	8,094	1,537	85	1	0	0
16	Meters	370	49,671	33,809	8,204	5,814	1,834	9	0	0
17	Installations on Cust. Prem./ARO	371/374	165	112	27	19	6	0	0	0
18	Street Lighting & Signal Systems	373	52,924	0	0	0	0	0	52,924	0
19	Subtotal - DISTRIBUTION PLANT	360-373	1,172,696	588,495	110,325	197,099	163,220	47,678	61,063	4,815
20										
21	**C. GENERAL PLANT**									
22	Land and Land Rights	389	952	517	91	134	116	32	59	3
23	Structures and Improvements	390	23,532	12,773	2,258	3,322	2,867	782	1,453	77
24	Office Furniture and Equipment	391	859	466	82	121	105	29	53	3
25	Passenger Cars - Transp Equipment	392	646	351	62	91	79	21	40	2
26	Stores Equipment	393	454	246	44	64	55	15	28	1
27	Tools, Shop & Garage Equipment	394	2,678	1,454	257	378	326	89	165	9
28	Laboratory Equipment	395	1,905	1,034	183	269	232	63	118	6
29	Communications Equipment	396	25,774	13,989	2,473	3,639	3,140	857	1,592	84
30	Miscellaneous Equipment	397/399.1	123	67	12	17	15	4	8	0
31	Subtotal - GENERAL PLANT	389-399	56,923	30,896	5,462	8,037	6,936	1,892	3,515	185
32										
33	**TOTAL UTILITY PLANT**		1,232,746	620,652	116,016	205,705	170,962	49,793	64,606	5,011
34										
35	**II. DEPRECIATION RESERVE**									
36	Production	108.3	(3,120)	(1,258)	(229)	(568)	(804)	(223)	(28)	(10)
37	Distribution	108.5	(488,824)	(245,144)	(45,956)	(82,097)	(68,213)	(19,926)	(25,469)	(2,019)
38	General	108.6	(24,583)	(13,343)	(2,359)	(3,471)	(2,995)	(817)	(1,518)	(80)
39	TOTAL DEPREC. RESERVE	108	(516,527)	(259,744)	(48,544)	(86,136)	(72,013)	(20,966)	(27,015)	(2,110)

Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40										
41	**III. OTHER RATE BASE ITEMS**									
42	Property Held for Future Use	131	204	103	19	34	28	8	10	1
43	Contributions in Aid of Construction	255	(103)	(52)	(10)	(17)	(14)	(4)	(5)	(0)
44	Materials and Supplies	255	6,378	3,210	605	1,067	886	258	327	26
45	Loss on Reacquired Debt	255	4,592	2,311	435	768	638	185	236	19
45	Cash Working Capital		17,789	9,582	1,765	2,578	2,273	619	913	59
46	Accumulated Deferred FIT	154	(113,088)	(56,937)	(10,643)	(18,871)	(15,684)	(4,568)	(5,927)	(460)
47	Customer Deposits	182	(3,283)	(24)	(1,563)	(1,565)	(131)	0	(0)	0
48	Injuries and Damages Reserve		(4,762)	(2,398)	(448)	(795)	(660)	(192)	(250)	(19)
49	Total - OTHER RATE BASE ITEMS	131-283	(92,273)	(44,205)	(9,839)	(16,800)	(12,664)	(3,694)	(4,696)	(376)
50										
51	**TOTAL RATE BASE**		623,946	316,703	57,633	102,769	86,285	25,134	32,896	2,526
52										
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**A. DISTRIBUTION EXPENSE**									
55	Purchased Power- Borderline	555	38	15	3	7	10	3	0	0
56	Operation Supervision & Engineering	580	1,481	698	140	244	218	61	113	6
57	Load Dispatching	581	2,372	956	174	432	612	169	22	8
58	Station Expenses	582	3,174	1,429	273	553	670	198	29	22
59	Overhead Line Expenses	583	5,315	2,673	511	1,030	788	233	54	26
60	Underground Line Expenses	584	1,849	863	165	333	354	105	17	12
61	Street Light and Signal Systems	585	530	0	0	0	0	0	530	0
62	Meter Expenses	586	2,842	1,934	469	333	105	1	0	0
63	Customer Installation Expenses	587	1,569	810	155	312	207	61	16	7
64	Misc. Distribution Expenses	588	12,495	5,889	1,180	2,063	1,840	518	955	51
65	Rents	589	109	55	10	18	15	4	6	0
66	Maint Supervision & Engineering	590	42	20	4	7	6	2	3	0
67	Maint of Structures	591	25	11	2	4	5	2	0	0
68	Maintenance of Station Equipment	592	3,332	1,500	287	580	704	208	30	24
69	Maintenance of Overhead Lines	593	18,701	9,404	1,797	3,625	2,774	820	189	93
70	Maintenance of Underground Lines	594	1,095	511	98	197	210	62	10	7
71	Maintenance of Line Transformers	595	263	144	27	55	28	8	0	0
72	Maintenance of Street Lights	596	1,652	0	0	0	0	0	1,652	0
73	Maintenance of Meters	597	318	216	53	37	12	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	57,202	27,128	5,347	9,831	8,558	2,455	3,627	256
75										

Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	1,197	1,026	107	39	21	0	4	0
78	Meter Reading Expenses	902	1,626	1,107	269	190	60	0	0	0
79	Customer Records & Collection Expense	903	11,449	9,813	1,019	373	205	0	39	0
80	Uncollectible Accounts- Delivery	904	4,301	2,258	464	633	664	101	176	4
81	Uncollectible Accounts- Commodity	904Com	0	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	1,074	950	103	19	2	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	19,647	15,154	1,961	1,254	953	102	219	4
84										
85	Supervision	907	88	40	38	8	2	0	0	0
86	Customer Assistance Exp Electric	908-909	1,860	846	812	160	36	5	1	0
85	Customer Assistance Expenses	910	3,460	1,898	341	431	604	166	18	2
86	Subtotal - Customer Service & Info.	907-913	5,408	2,784	1,191	599	642	171	19	2
87										
88	Total - CUST. ACCT. & SERV. EXP.	901-919	25,055	17,939	3,152	1,853	1,595	273	238	6
89										
90	**C. ADMINISTRATIVE AND GENERAL**									
91	GENERAL EXPENSES									
92	A&G-Salaries	920	9,223	5,006	885	1,302	1,124	307	570	30
93	A&G-Office Supplies	921	9,498	5,155	911	1,341	1,157	316	587	31
94	A&G-Outside Services Employed	923	1,902	1,032	183	269	232	63	117	6
95	Property Insurance	924	1,037	522	98	173	144	42	54	4
96	Injuries & Damages Insurance	925	6,804	3,426	640	1,135	944	275	357	28
97	Employee Pensions & Benefits	926	22,946	12,454	2,202	3,240	2,796	763	1,417	75
98	Regulatory Comm Expenses	928	5,083	2,580	470	837	703	205	268	21
99	A&G-Misc Expenses	930200	3,870	1,560	284	704	998	276	35	13
100	A&G-Research & Development	930210	125	63	12	21	17	5	7	1
101	A&G-Rents	931	4,590	2,491	440	648	559	153	283	15
101	A&G Maint-General Plant-Elec	935	252	137	24	36	31	8	16	1
102	TOTAL A&G EXPENSES	920-932	65,330	34,427	6,148	9,705	8,704	2,412	3,710	223
103										
104	TOTAL OPERATING EXPENSES		147,587	79,494	14,647	21,389	18,857	5,140	7,575	485
105										
106	**II. DEPRECIATION EXPENSE**									
107	Depreciation Expense	403	41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
108	TOTAL DEPREC. EXPENSE	403	41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
109										

Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Municipal taxes	408	20,085	10,112	1,890	3,352	2,785	811	1,053	82
113	Payroll taxes	408	3,700	2,008	355	522	451	123	228	12
114	Other taxes	408	275	138	26	46	38	11	14	1
115	Subtotal - General Taxes		24,060	12,259	2,271	3,920	3,274	945	1,296	95
116										
117	**B. FEDERAL / STATE INCOME TAXES**									
118	Amort. ITC		(488)	(246)	(46)	(81)	(68)	(20)	(26)	(2)
119	Federal Income Tax Expense		(3,198)	(1,623)	(295)	(527)	(442)	(129)	(169)	(13)
120	Subtotal - Federal / State Income Taxes	409-411	(3,686)	(1,869)	(341)	(608)	(510)	(149)	(194)	(15)
121										
122	TOTAL TAXES	408-411	20,374	10,390	1,930	3,312	2,765	797	1,101	80
123										
124	**C. OTHER**									
125	Merger / Synergy Benefits		(850)	(431)	(79)	(140)	(118)	(34)	(45)	(3)
126	Amortization of Loss on Reacq Debt		686	345	65	114	95	28	36	3
127	Interest on Customer deposits		75	1	36	36	3	0	0	0
128	Subtotal- Other		(89)	(86)	22	10	(19)	(7)	(9)	(1)
129										
130	TOTAL EXPENSES		209,338	110,675	20,501	31,630	27,353	7,605	10,841	733
131										
132	**IV. OPERATING REVENUES at Current Rates**									
133	Distribution charge revenue	440	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
134	Forfeited discounts	450-451	2,230	1,752	170	174	134	0	1	0
135	Rent from Utility property	451Misc	2,644	1,365	261	526	349	103	27	12
136	Other revenue	454	2,948	1,548	318	434	455	70	121	3
137	Total Operating Revenues		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
138										
139	TOTAL EXPENSES		209,338	110,675	20,501	31,630	27,353	7,605	10,841	733
140										
141	**V. NET INCOME at Current Rates**		13,904	7,094	3,484	1,211	6,842	(2,352)	(1,857)	(518)
142										

Class Cost of Service Study ($000s)
TOTAL DISTRIBUTION REVENUE REQUIREMENT CLASS ALLOCATION

	Account Description	Account No.	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
				A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**									
144	OPERATING REVENUES									
145	Utility Revenues	440-446	215,420	113,105	23,237	31,707	33,256	5,080	8,834	201
146	Other Operating Revenues	450-456	7,822	4,665	749	1,134	938	173	149	14
147	Total Operating Revenues		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
148										
149	OPERATING EXPENSES									
150	Distribution	580-599	57,202	27,128	5,347	9,831	8,558	2,455	3,627	256
151	Customer Acctg & Service	901-919	25,055	17,939	3,152	1,853	1,595	273	238	6
152	Admin & General	920-932	65,330	34,427	6,148	9,705	8,704	2,412	3,710	223
153	Total Operating Expenses		147,587	79,494	14,647	21,389	18,857	5,140	7,575	485
154										
155	Depreciation Expense	403	41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
156	Taxes Other Than Income Tax / Other	408	23,971	12,173	2,293	3,930	3,255	939	1,287	94
157	INCOME BEFORE INCOME TAXES		10,218	5,225	3,143	603	6,332	(2,500)	(2,052)	(533)
158	Income Taxes	409-411	(3,686)	(1,869)	(341)	(608)	(510)	(149)	(194)	(15)
159	NET INCOME		13,904	7,094	3,484	1,211	6,842	(2,352)	(1,857)	(518)
160										
161	RATE BASE		623,946	316,703	57,633	102,769	86,285	25,134	32,896	2,526
162	Return on Rate Base		2.23%	2.24%	6.04%	1.18%	7.93%	(9.36%)	(5.65%)	(20.50%)
163										
164	**REVENUE REQUIREMENTS**									
165	Target Rate of Return		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		623,946	316,703	57,633	102,769	86,285	25,134	32,896	2,526
167										
168	Operating expenses		147,587	79,494	14,647	21,389	18,857	5,140	7,575	485
169	Additional uncollectibles expense		719	565	55	56	43	0	0	0
170	Depreciation expense		41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
171	General taxes / Other		23,971	12,173	2,293	3,930	3,255	939	1,287	94
172	Subtotal- Operating Costs to recover		213,743	113,109	20,897	32,294	27,906	7,753	11,035	748
173										
174	Target Return on Rate Base- After taxes		56,030	28,440	5,175	9,229	7,748	2,257	2,954	227
175										
176	Income taxes to recover		18,999	9,644	1,755	3,129	2,627	765	1,002	77
177										
178	**TOTAL REVENUE REQUIREMENT**		288,772	151,192	27,828	44,652	38,282	10,776	14,991	1,052
179										
180	Revenue at Current rates		223,242	117,770	23,985	32,841	34,194	5,253	8,983	215
181	**Revenue Excess (Deficiency)**		(65,530)	(33,423)	(3,843)	(11,811)	(4,087)	(5,523)	(6,008)	(837)

Class Cost of Service Study ($000s)
FUNCTIONALIZATON

	Account Description	Account No.	Balance	Allocator	SubTransmission	Primary Dist	Secondary Dist	Billing
1	**I. ELECTRIC PLANT IN SERVICE**							
2	**A. PRODUCTION PLANT**							
3	Production Plant		3,127	SUBT	3,127	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	3,127		3,127	0	0	0
5								
6	**B. DISTRIBUTION PLANT**							
7	Land and Land Rights	360	9,586	STATIONS	0	9,586	0	0
8	Structures and Improvements	361	7,196	STATIONS	0	7,196	0	0
9	Station Equipment	362	171,209	STATIONS	0	171,209	0	0
10	Poles, Towers and Fixtures	364	185,255	Func-364	6,613	109,288	69,354	0
11	Overhead Conductors and Devices	365	265,515	Func-365	17,753	182,924	64,837	0
12	Underground Conduit	366	62,534	Func-366	4,419	49,988	8,127	0
13	Underground Conductors & Devices	367	135,960	Func-367	10,119	113,255	12,586	0
14	Line Transformers	368	160,299	PRIM	0	160,299	0	0
15	Services	369	72,382	SEC	0	0	72,382	0
16	Meters	370	49,671	BILL	0	0	0	49,671
17	Installations on Cust. Prem./ARO	371/374	165	BILL	0	0	0	165
18	Street Lighting & Signal Systems	373	52,924	SEC	0	0	52,924	0
19	Subtotal - DISTRIBUTION PLANT	360-373	1,172,696		38,905	803,746	280,210	49,836
20								
21	**C. GENERAL PLANT**							
22	Land and Land Rights	389	952	LABOR	115	380	163	294
23	Structures and Improvements	390	23,532	LABOR	2,851	9,403	4,018	7,259
24	Office Furniture and Equipment	391	859	LABOR	104	343	147	265
25	Passenger Cars - Transp Equipment	392	646	LABOR	78	258	110	199
26	Stores Equipment	393	454	LABOR	55	181	78	140
27	Tools, Shop & Garage Equipment	394	2,678	LABOR	324	1,070	457	826
28	Laboratory Equipment	395	1,905	LABOR	231	761	325	588
29	Communications Equipment	396	25,774	LABOR	3,123	10,299	4,401	7,951
30	Miscellaneous Equipment	397/399.1	123	LABOR	15	49	21	38
31	Subtotal - GENERAL PLANT	389-399	56,923		6,897	22,747	9,719	17,560
32								
33	**TOTAL UTILITY PLANT**		1,232,746		48,929	826,492	289,929	67,396
34								
35	**II. DEPRECIATION RESERVE**							
36	Production	108.3	(3,120)	SUBT	(3,120)	0	0	0
37	Distribution	108.5	(488,824)	DISTPT	(16,217)	(335,032)	(116,802)	(20,774)
38	General	108.6	(24,583)	LABOR	(2,979)	(9,823)	(4,197)	(7,584)
39	TOTAL DEPREC. RESERVE	108	(516,527)		(22,316)	(344,855)	(120,999)	(28,357)

Class Cost of Service Study ($000s)
FUNCTIONALIZATON

	Account Description	Account No.	Balance	Allocator	SubTransmission	Primary Dist	Secondary Dist	Billing
40								
41	**III. OTHER RATE BASE ITEMS**							
42	Property Held for Future Use	131	204	PLANT	8	137	48	11
43	Contributions in Aid of Construction	255	(103)	PLANT	(4)	(69)	(24)	(6)
44	Materials and Supplies	255	6,378	PLANT	253	4,276	1,500	349
45	Loss on Reacquired Debt	255	4,592	PLANT	182	3,079	1,080	251
45	Cash Working Capital		17,789	OPEXP	1,523	7,652	3,067	5,547
46	Accumulated Deferred FIT	154	(113,088)	PLANT	(4,489)	(75,820)	(26,597)	(6,183)
47	Customer Deposits	182	(3,283)	BILL	0	0	0	(3,283)
48	Injuries and Damages Reserve		(4,762)	PLANT	(189)	(3,193)	(1,120)	(260)
49	Total - OTHER RATE BASE ITEMS	131-283	(92,273)		(2,715)	(63,938)	(22,046)	(3,574)
50								
51	**TOTAL RATE BASE**		623,946		23,898	417,699	146,883	35,465
52								
53	**I. OPERATING AND MAINTENANCE EXPENSES**							
54	**A. DISTRIBUTION EXPENSE**							
55	Purchased Power- Borderline	555	38	SUBT	38	0	0	0
56	Operation Supervision & Engineering	580	1,481	Dist-LABOR	224	738	315	204
57	Load Dispatching	581	2,372	SUBT	2,372	0	0	0
58	Station Expenses	582	3,174	STATIONS	0	3,174	0	0
59	Overhead Line Expenses	583	5,315	OH_Total	287	3,445	1,582	0
60	Underground Line Expenses	584	1,849	Func-367	138	1,540	171	0
61	Street Light and Signal Systems	585	530	SEC	0	0	530	0
62	Meter Expenses	586	2,842	BILL	0	0	0	2,842
63	Customer Installation Expenses	587	1,569	Func-364	56	926	587	0
64	Misc. Distribution Expenses	588	12,495	Dist-LABOR	1,888	6,227	2,661	1,719
65	Rents	589	109	DISTPT	4	75	26	5
66	Maint Supervision & Engineering	590	42	Dist-LABOR	6	21	9	6
67	Maint of Structures	591	25	STATIONS	0	25	0	0
68	Maintenance of Station Equipment	592	3,332	STATIONS	0	3,332	0	0
69	Maintenance of Overhead Lines	593	18,701	OH_Total	1,011	12,123	5,567	0
70	Maintenance of Underground Lines	594	1,095	Func-367	81	912	101	0
71	Maintenance of Line Transformers	595	263	PRIM	0	263	0	0
72	Maintenance of Street Lights	596	1,652	SEC	0	0	1,652	0
73	Maintenance of Meters	597	318	BILL	0	0	0	318
74	Total - OPER. AND MAINT. EXP.	500-599	57,202		6,105	32,802	13,202	5,093
75								

Class Cost of Service Study ($000s)
FUNCTIONALIZATON

	Account Description	Account No.	Balance	Allocator	SubTransmission	Primary Dist	Secondary Dist	Billing
76	**B. CUSTOMER ACCOUNTS AND SERVICE**							
77	Supervision	901	1,197	BILL	0	0	0	1,197
78	Meter Reading Expenses	902	1,626	BILL	0	0	0	1,626
79	Customer Records & Collection Expense	903	11,449	BILL	0	0	0	11,449
80	Uncollectible Accounts- Delivery	904	4,301	BILL	0	0	0	4,301
81	Uncollectible Accounts- Commodity	904Com	0	BILL	0	0	0	0
82	Misc Customer Accounts Expenses	905	1,074	BILL	0	0	0	1,074
83	Subtotal - Customer Accounts Exp.	901-905	19,647		0	0	0	19,647
84								
85	Supervision	907	88	BILL	0	0	0	88
86	Customer Assistance Exp Electric	908-909	1,860	BILL	0	0	0	1,860
85	Customer Assistance Expenses	910	3,460	BILL	0	0	0	3,460
86	Subtotal - Customer Service & Info.	907-913	5,408		0	0	0	5,408
87								
88	Total - CUST. ACCT. & SERV. EXP.	901-919	25,055		0	0	0	25,055
89								
90	**C. ADMINISTRATIVE AND GENERAL**							
91	GENERAL EXPENSES							
92	A&G-Salaries	920	9,223	LABOR	1,118	3,686	1,575	2,845
93	A&G-Office Supplies	921	9,498	LABOR	1,151	3,795	1,622	2,930
94	A&G-Outside Services Employed	923	1,902	LABOR	230	760	325	587
95	Property Insurance	924	1,037	PLANT	41	695	244	57
96	Injuries & Damages Insurance	925	6,804	PLANT	270	4,562	1,600	372
97	Employee Pensions & Benefits	926	22,946	LABOR	2,780	9,169	3,918	7,079
98	Regulatory Comm Expenses	928	5,083	RATEBASE	195	3,403	1,197	289
99	A&G-Misc Expenses	930200	3,870	PLANT	154	2,595	910	212
100	A&G-Research & Development	930210	125	RATEBASE	5	84	29	7
101	A&G-Rents	931	4,590	LABOR	556	1,834	784	1,416
101	A&G Maint-General Plant-Elec	935	252	LABOR	31	101	43	78
102	TOTAL A&G EXPENSES	920-932	65,330		6,530	30,683	12,246	15,871
103								
104	TOTAL OPERATING EXPENSES		147,587		12,635	63,485	25,448	46,018
105								
106	**II. DEPRECIATION EXPENSE**							
107	Depreciation Expense	403	41,466	PLANT	1,646	27,801	9,752	2,267
108	TOTAL DEPREC. EXPENSE	403	41,466		1,646	27,801	9,752	2,267
109								

Class Cost of Service Study ($000s)
FUNCTIONALIZATON

	Account Description	Account No.	Balance	Allocator	SubTransmission	Primary Dist	Secondary Dist	Billing
110	**III. TAXES and OTHER**							
111	**A. GENERAL TAXES**							
112	Municipal taxes	408.3	20,085	PLANT	797	13,466	4,724	1,098
113	Payroll taxes	408.4	3,700	LABOR	448	1,479	632	1,141
114	Other taxes	408	275	PLANT	11	184	65	15
115	Subtotal - General Taxes		24,060		1,256	15,129	5,420	2,255
116								
117	**B. FEDERAL / STATE INCOME TAXES**							
118	Amort. ITC		(488)	PLANT	(19)	(327)	(115)	(27)
119	Federal Income Tax Expense		(3,198)	RATEBASE	(122)	(2,141)	(753)	(182)
120	Subtotal - Federal / State Income Taxes	409-411	(3,686)		(142)	(2,468)	(868)	(208)
121								
122	TOTAL TAXES	408-411	20,374		1,115	12,661	4,553	2,046
123								
124	**C. OTHER**							
125	Merger / Synergy Benefits		(850)	RATEBASE	(33)	(569)	(200)	(48)
126	Amortization of Loss on Reacq Debt		686	PLANT	27	460	161	38
127	Interest on Customer deposits		75	BILL	0	0	0	75
128	Subtotal- Other		(89)		(5)	(109)	(39)	64
129								
130	**TOTAL EXPENSES**		209,338		15,390	103,837	39,715	50,396
131								
132	**IV. OPERATING REVENUES at Current Rates**							
133	Distribution charge revenue	440	215,420	RevReq_PF	15,027	110,851	41,921	47,621
134	Forfeited discounts	450-451	2,230	BILL	0	0	0	2,230
135	Rent from Utility property	451Misc	2,644	Func-364	94	1,560	990	0
136	Other revenue	454	2,948	RevReq_PF	206	1,517	574	652
137	Total Operating Revenues		223,242		15,327	113,928	43,485	50,503
138								
139	TOTAL EXPENSES		209,338		15,390	103,837	39,715	50,396
140								
141	**V. NET INCOME at Current Rates**		13,904		(64)	10,091	3,770	107
142								

Class Cost of Service Study ($000s)
FUNCTIONALIZATON

	Account Description	Account No.	Balance	Allocator	SubTransmission	Primary Dist	Secondary Dist	Billing
143	**SUMMARY REPORT**							
144	OPERATING REVENUES							
145	Utility Revenues	440-446	215,420		15,027	110,851	41,921	47,621
146	Other Operating Revenues	450-456	7,822		300	3,077	1,564	2,882
147	Total Operating Revenues		223,242		15,327	113,928	43,485	50,503
148								
149	OPERATING EXPENSES							
150	Distribution	580-599	57,202		6,105	32,802	13,202	5,093
151	Customer Acctg & Service	901-919	25,055		0	0	0	25,055
152	Admin & General	920-932	65,330		6,530	30,683	12,246	15,871
153	Total Operating Expenses		147,587		12,635	63,485	25,448	46,018
154								
155	Depreciation Expense	403	41,466		1,646	27,801	9,752	2,267
156	Taxes Other Than Income Tax / Other	408	23,971		1,251	15,020	5,381	2,319
157	INCOME BEFORE INCOME TAXES		10,218		(206)	7,622	2,903	(101)
158	Income Taxes	409-411	(3,686)		(142)	(2,468)	(868)	(208)
159	**NET INCOME**		13,904		(64)	10,091	3,770	107
160								
161	**RATE BASE**		623,946		23,898	417,699	146,883	35,465
162	Return on Rate Base		2.23%		-0.27%	2.42%	2.57%	0.30%
163								
164	**REVENUE REQUIREMENTS**							
165	Target Rate of Return		8.9800%		8.9800%	8.9800%	8.9800%	8.9800%
166	Rate Base		623,946		23,898	417,699	146,883	35,465
167								
168	Operating expenses		147,587		12,635	63,485	25,448	46,018
169	Additional uncollectibles expense		719	BILL	0	0	0	719
170	Depreciation expense		41,466		1,646	27,801	9,752	2,267
171	General taxes / Other		23,971		1,251	15,020	5,381	2,319
172	Subtotal- Operating Costs to recover		213,743		15,532	106,305	40,582	51,323
173								
174	Target Return on Rate Base- After taxes		56,030		2,146	37,509	13,190	3,185
175								
176	Income taxes to recover		18,999	RATEBASE	728	12,719	4,473	1,080
177								
178	**TOTAL REVENUE REQUIREMENT**		288,772		18,406	156,534	58,245	55,588
179								
180	Revenue at Current rates		223,242		15,327	113,928	43,485	50,503
181	Revenue Excess (Deficiency)		(65,530)		(3,079)	(42,606)	(14,760)	(5,085)

Class Cost of Service Study ($000s)
CLASSIFICATION

	Account Description	Account No.	Secondary Dist Dollars	Allocator	Secondary Dist Demand	Secondary Dist Energy	Secondary Dist Customer
1	**I. ELECTRIC PLANT IN SERVICE**						
2	**A. PRODUCTION PLANT**						
3	Production Plant		0	None	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	0		0	0	0
5							
6	**B. DISTRIBUTION PLANT**						
7	Land and Land Rights	360	0	None	0	0	0
8	Structures and Improvements	361	0	None	0	0	0
9	Station Equipment	362	0	None	0	0	0
10	Poles, Towers and Fixtures	364	69,354	DEMAND	69,354	0	0
11	Overhead Conductors and Devices	365	64,837	DEMAND	64,837	0	0
12	Underground Conduit	366	8,127	DEMAND	8,127	0	0
13	Underground Conductors & Devices	367	12,586	DEMAND	12,586	0	0
14	Line Transformers	368	0	DEMAND	0	0	0
15	Services	369	72,382	CUST	0	0	72,382
16	Meters	370	0	None	0	0	0
17	Installations on Cust. Prem./ARO	371/374	0	None	0	0	0
18	Street Lighting & Signal Systems	373	52,924	CUST	0	0	52,924
19	Subtotal - DISTRIBUTION PLANT	360-373	280,210		154,904	0	125,306
20							
21	**C. GENERAL PLANT**						
22	Land and Land Rights	389	163	SECLABOR	110	0	52
23	Structures and Improvements	390	4,018	SECLABOR	2,720	0	1,298
24	Office Furniture and Equipment	391	147	SECLABOR	99	0	47
25	Passenger Cars - Transp Equipment	392	110	SECLABOR	75	0	36
26	Stores Equipment	393	78	SECLABOR	52	0	25
27	Tools, Shop & Garage Equipment	394	457	SECLABOR	310	0	148
28	Laboratory Equipment	395	325	SECLABOR	220	0	105
29	Communications Equipment	396	4,401	SECLABOR	2,979	0	1,421
30	Miscellaneous Equipment	397/399.1	21	SECLABOR	14	0	7
31	Subtotal - GENERAL PLANT	389-399	9,719		6,580	0	3,139
32							
33	**TOTAL UTILITY PLANT**		289,929		161,484	0	128,445
34							
35	**II. DEPRECIATION RESERVE**						
36	Production	108.3	0	None	0	0	0
37	Distribution	108.5	(116,802)	SEC_DiPT	(64,570)	0	(52,232)
38	General	108.6	(4,197)	SECLABOR	(2,842)	0	(1,356)
39	TOTAL DEPREC. RESERVE	108	(120,999)		(67,411)	0	(53,588)

Class Cost of Service Study ($000s)
CLASSIFICATION

	Account Description	Account No.	Secondary Dist Dollars	Allocator	Secondary Dist Demand	Secondary Dist Energy	Secondary Dist Customer
40							
41	**III. OTHER RATE BASE ITEMS**						
42	Property Held for Future Use	131	48	SEC_DiPT	27	0	21
43	Contributions in Aid of Construction	255	(24)	SEC_DiPT	(13)	0	(11)
44	Materials and Supplies	255	1,500	SEC_DiPT	829	0	671
45	Loss on Reacquired Debt	255	1,080	SEC_DiPT	597	0	483
45	Cash Working Capital		3,067	SEC_EXP	2,153	0	914
46	Accumulated Deferred FIT	154	(26,597)	SECPT	(14,814)	0	(11,783)
47	Customer Deposits	182	0	SECPT	0	0	0
48	Injuries and Damages Reserve		(1,120)	SECPT	(624)	0	(496)
49	Total - OTHER RATE BASE ITEMS	131-283	(22,046)		(11,846)	0	(10,200)
50							
51	**TOTAL RATE BASE**		146,883		82,227	0	64,657
52							
53	**I. OPERATING AND MAINTENANCE EXPENSES**						
54	**A. DISTRIBUTION EXPENSE**						
55	Purchased Power- Borderline	555	0	SECLABOR	0	0	0
56	Operation Supervision & Engineering	580	315	SEC-DxLABOR	214	0	102
57	Load Dispatching	581	0	None	0	0	0
58	Station Expenses	582	0	None	0	0	0
59	Overhead Line Expenses	583	1,582	DEMAND	1,582	0	0
60	Underground Line Expenses	584	171	DEMAND	171	0	0
61	Street Light and Signal Systems	585	530	CUST	0	0	530
62	Meter Expenses	586	0	None	0	0	0
63	Customer Installation Expenses	587	587	DEMAND	587	0	0
64	Misc. Distribution Expenses	588	2,661	SEC-DxLABOR	1,801	0	859
65	Rents	589	26	SEC_DiPT	14	0	12
66	Maint Supervision & Engineering	590	9	SEC-DxLABOR	6	0	3
67	Maint of Structures	591	0	None	0	0	0
68	Maintenance of Station Equipment	592	0	None	0	0	0
69	Maintenance of Overhead Lines	593	5,567	DEMAND	5,567	0	0
70	Maintenance of Underground Lines	594	101	DEMAND	101	0	0
71	Maintenance of Line Transformers	595	0	CUST	0	0	0
72	Maintenance of Street Lights	596	1,652	CUST	0	0	1,652
73	Maintenance of Meters	597	0	SEC_DiPT	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	13,202		10,045	0	3,158
75							

Class Cost of Service Study ($000s)
CLASSIFICATION

	Account Description	Account No.	Secondary Dist Dollars	Allocator	Secondary Dist Demand	Secondary Dist Energy	Secondary Dist Customer
76	**B. CUSTOMER ACCOUNTS AND SERVICE**						
77	Supervision	901	0	None	0	0	0
78	Meter Reading Expenses	902	0	None	0	0	0
79	Customer Records & Collection Expense	903	0	None	0	0	0
80	Uncollectible Accounts- Delivery	904	0	None	0	0	0
81	Uncollectible Accounts- Commodity	904Com	0	None	0	0	0
82	Misc Customer Accounts Expenses	905	0	None	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0
84							
85	Supervision	907	0	None	0	0	0
86	Customer Assistance Exp Electric	908-909	0	None	0	0	0
85	Customer Assistance Expenses	910	0	None	0	0	0
86	Subtotal - Customer Service & Info.	907-913	0		0	0	0
87							
88	Total - CUST. ACCT. & SERV. EXP.	901-919	0		0	0	0
89							
90	**C. ADMINISTRATIVE AND GENERAL**						
91	GENERAL EXPENSES						
92	A&G-Salaries	920	1,575	SECLABOR	1,066	0	509
93	A&G-Office Supplies	921	1,622	SECLABOR	1,098	0	524
94	A&G-Outside Services Employed	923	325	SECLABOR	220	0	105
95	Property Insurance	924	244	SECPT	136	0	108
96	Injuries & Damages Insurance	925	1,600	SECPT	891	0	709
97	Employee Pensions & Benefits	926	3,918	SECLABOR	2,653	0	1,265
98	Regulatory Comm Expenses	928	1,197	SEC_RB	670	0	527
99	A&G-Misc Expenses	930,200	910	SECPT	507	0	403
100	A&G-Research & Development	930,210	29	SEC_RB	16	0	13
101	A&G-Rents	931	784	SECLABOR	531	0	253
101	A&G Maint-General Plant-Elec	935	43	SECLABOR	29	0	14
102	TOTAL A&G EXPENSES	920-932	12,246		7,817	0	4,429
103							
104	TOTAL OPERATING EXPENSES		25,448		17,861	0	7,587
105							
106	**II. DEPRECIATION EXPENSE**						
107	Depreciation Expense	403	9,752	SECPT	5,432	0	4,321
108	TOTAL DEPREC. EXPENSE	403	9,752		5,432	0	4,321
109							

Class Cost of Service Study ($000s)
CLASSIFICATION

	Account Description	Account No.	Secondary Dist Dollars	Allocator	Secondary Dist Demand	Secondary Dist Energy	Secondary Dist Customer
110	**III. TAXES and OTHER**						
111	**A. GENERAL TAXES**						
112	Municipal taxes	408	4,724	SECPT	2,631	0	2,093
113	Payroll taxes	408	632	SECLABOR	428	0	204
114	Other taxes	408	65	SECPT	36	0	29
115	Subtotal - General Taxes		5,420		3,095	0	2,325
116							
117	**B. FEDERAL / STATE INCOME TAXES**						
118	Amort. ITC		(115)	SECPT	(64)	0	(51)
119	Federal Income Tax Expense		(753)	SEC_RB	(421)	0	(331)
120	Subtotal - Federal / State Income Taxes	409-411	(868)		(485)	0	(382)
121							
122	TOTAL TAXES	408-411	4,553		2,609	0	1,943
123							
124	**C. OTHER**						
125	Merger / Synergy Benefits		(200)	SECPT	(111)	0	(89)
126	Amortization of Loss on Reacq Debt		161	SECPT	90	0	71
127	Interest on Customer deposits		0	CUST	0	0	0
128	Subtotal- Other		(39)		(22)	0	(17)
129							
130	TOTAL EXPENSES		39,715		25,881	0	13,834
131				SEC_RevReq_PF			
132	**IV. OPERATING REVENUES at Current Rates**						
133	Distribution charge revenue	440	41,921	SECPT	23,349	0	18,572
134	Forfeited discounts	450-451	0	None	0	0	0
135	Rent from Utility property	451Misc	990	DEMAND	990	0	0
136	Other revenue	454	574	SECPT	320	0	254
137	Total Operating Revenues		43,485		24,659	0	18,826
138							
139	TOTAL EXPENSES		39,715		25,881	0	13,834
140							
141	**V. NET INCOME at Current Rates**		3,770		(1,222)	0	4,993
142							

Class Cost of Service Study ($000s)
CLASSIFICATION

	Account Description	Account No.	Secondary Dist Dollars	Allocator	Secondary Dist Demand	Secondary Dist Energy	Secondary Dist Customer
143	**SUMMARY REPORT**						
144	OPERATING REVENUES						
145	Utility Revenues	440-446	41,921		23,349	0	18,572
146	Other Operating Revenues	450-456	1,564		1,309	0	254
147	Total Operating Revenues		43,485		24,659	0	18,826
148							
149	OPERATING EXPENSES						
150	Distribution	580-599	13,202		10,045	0	3,158
151	Customer Acctg & Service	901-919	0		0	0	0
152	Admin & General	920-932	12,246		7,817	0	4,429
153	Total Operating Expenses		25,448		17,861	0	7,587
154							
155	Depreciation Expense	403	9,752		5,432	0	4,321
156	Taxes Other Than Income Tax / Other	408	5,381		3,073	0	2,308
157	INCOME BEFORE INCOME TAXES		2,903		(1,708)	0	4,610
158	Income Taxes	409-411	(868)		(485)	0	(382)
159	NET INCOME		3,770		(1,222)	0	4,993
160							
161	RATE BASE		146,883		82,227	0	64,657
162	Return on Rate Base						
163							
164	**REVENUE REQUIREMENTS**						
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%
166	Rate Base		146,883		82,227	0	64,657
167							
168	Operating expenses		25,448		17,861	0	7,587
169	Additional uncollectibles expense		0	SECPT	0	0	0
170	Depreciation expense		9,752		5,432	0	4,321
171	General taxes / Other		5,381		3,073	0	2,308
172	Subtotal- Operating Costs to recover		40,582		26,366	0	14,216
173							
174	Target Return on Rate Base- After taxes		13,190		7,384	0	5,806
175							
176	Income taxes to recover		4,473	SEC_RB	2,504	0	1,969
177							
178	**TOTAL REVENUE REQUIREMENT**		58,245		36,254	0	21,991
179							
180	Revenue at Current rates		43,485		24,659	0	18,826
181	Revenue Excess (Deficiency)		(14,760)		(11,596)	0	(3,164)

Class Cost of Service Study ($000s)
SUBTRANSMISSION DEMAND - CLASS ALLOCATION

	Account Description	Account No.	SubTransmiss Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	**I. ELECTRIC PLANT IN SERVICE**										
2	**A. PRODUCTION PLANT**										
3	Production Plant		3,127	MWh-Gen	1,261	229	569	806	223	28	10
4	Subtotal - PRODUCTION PLANT	350-359	3,127		1,261	229	569	806	223	28	10
5											
6	**B. DISTRIBUTION PLANT**										
7	Land and Land Rights	360	0	None	0	0	0	0	0	0	0
8	Structures and Improvements	361	0	None	0	0	0	0	0	0	0
9	Station Equipment	362	0	None	0	0	0	0	0	0	0
10	Poles, Towers and Fixtures	364	6,613	NCP_at_115	2,977	569	1,151	1,397	413	60	47
11	Overhead Conductors and Devices	365	17,753	NCP_at_115	7,991	1,527	3,091	3,749	1,108	161	125
12	Underground Conduit	366	4,419	NCP_at_115	1,989	380	769	933	276	40	31
13	Underground Conductors & Devices	367	10,119	NCP_at_115	4,555	870	1,762	2,137	632	92	71
14	Line Transformers	368	0	None	0	0	0	0	0	0	0
15	Services	369	0	None	0	0	0	0	0	0	0
16	Meters	370	0	None	0	0	0	0	0	0	0
17	Installations on Cust. Prem./ARO	371/374	0	None	0	0	0	0	0	0	0
18	Street Lighting & Signal Systems	373	0	None	0	0	0	0	0	0	0
19	Subtotal - DISTRIBUTION PLANT	360-373	38,905		17,512	3,347	6,774	8,217	2,428	353	275
20											
21	**C. GENERAL PLANT**										
22	Land and Land Rights	389	115	SUBT-LAB-D	47	9	21	29	8	1	0
23	Structures and Improvements	390	2,851	SUBT-LAB-D	1,174	216	515	711	199	26	11
24	Office Furniture and Equipment	391	104	SUBT-LAB-D	43	8	19	26	7	1	0
25	Passenger Cars - Transp Equipment	392	78	SUBT-LAB-D	32	6	14	20	5	1	0
26	Stores Equipment	393	55	SUBT-LAB-D	23	4	10	14	4	0	0
27	Tools, Shop & Garage Equipment	394	324	SUBT-LAB-D	134	25	59	81	23	3	1
28	Laboratory Equipment	395	231	SUBT-LAB-D	95	17	42	58	16	2	1
29	Communications Equipment	396	3,123	SUBT-LAB-D	1,285	236	564	779	218	28	12
30	Miscellaneous Equipment	397/399.1	15	SUBT-LAB-D	6	1	3	4	1	0	0
31	Subtotal - GENERAL PLANT	389-399	6,897	None	2,839	521	1,245	1,720	481	63	27
32											
33	**TOTAL UTILITY PLANT**		48,929		21,612	4,097	8,588	10,743	3,133	443	312
34											
35	**II. DEPRECIATION RESERVE**										
36	Production	108.3	(3,120)	SUBT-PrPT-D	(1,258)	(229)	(568)	(804)	(223)	(28)	(10)
37	Distribution	108.5	(16,217)	SUBT-DxPT-D	(7,300)	(1,395)	(2,824)	(3,425)	(1,012)	(147)	(114)
38	General	108.6	(2,979)	SUBT-LAB-D	(1,226)	(225)	(538)	(743)	(208)	(27)	(12)
39	TOTAL DEPREC. RESERVE	108	(22,316)		(9,783)	(1,849)	(3,929)	(4,972)	(1,443)	(202)	(136)

Class Cost of Service Study ($000s)

SUBTRANSMISSION DEMAND - CLASS ALLOCATION

	Account Description	Account No.	SubTransmiss Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40											
41	**III. OTHER RATE BASE ITEMS**										
42	Property Held for Future Use	131	8	SUBT-PT-D	4	1	1	2	1	0	0
43	Contributions in Aid of Construction	255	(4)	SUBT-PT-D	(2)	(0)	(1)	(1)	(0)	(0)	(0)
44	Materials and Supplies	255	253	SUBT-PT-D	112	21	44	56	16	2	2
45	Loss on Reacquired Debt	255	182	SUBT-PT-D	81	15	32	40	12	2	1
45	Cash Working Capital		1,523	SUBT-EXP-D	635	117	274	371	104	15	6
46	Accumulated Deferred FIT	154	(4,489)	SUBT-PT-D	(1,983)	(376)	(788)	(986)	(287)	(41)	(29)
47	Customer Deposits	182	0	None	0	0	0	0	0	0	0
48	Injuries and Damages Reserve		(189)	SUBT-PT-D	(83)	(16)	(33)	(42)	(12)	(2)	(1)
49	Total - OTHER RATE BASE ITEM	131-283	(2,715)		(1,237)	(238)	(470)	(559)	(167)	(24)	(21)
50											
51	**TOTAL RATE BASE**		23,898		10,591	2,011	4,189	5,212	1,523	218	155
52											
53	**I. OPERATING AND MAINTENANCE EXPENSES**										
54	**A. DISTRIBUTION EXPENSE**										
55	Purchased Power- Borderline	555	38	MWh-Gen	15	3	7	10	3	0	0
56	Operation Supervision & Engineerin	580	224	SUBT-DxLAB-D	92	17	40	56	16	2	1
57	Load Dispatching	581	2,372	MWh-Gen	956	174	432	612	169	22	8
58	Station Expenses	582	0	None	0	0	0	0	0	0	0
59	Overhead Line Expenses	583	287	NCP_at_115	129	25	50	61	18	3	2
60	Underground Line Expenses	584	138	NCP_at_115	62	12	24	29	9	1	1
61	Street Light and Signal Systems	585	0	None	0	0	0	0	0	0	0
62	Meter Expenses	586	0	None	0	0	0	0	0	0	0
63	Customer Installation Expenses	587	56	NCP_at_115	25	5	10	12	3	1	0
64	Misc. Distribution Expenses	588	1,888	SUBT-DxLAB-D	777	143	341	471	132	17	7
65	Rents	589	4	SUBT-PT-D	2	0	1	1	0	0	0
66	Maint Supervision & Engineering	590	6	SUBT-DxLAB-D	3	0	1	2	0	0	0
67	Maint of Structures	591	0	None	0	0	0	0	0	0	0
68	Maintenance of Station Equipment	592	0	None	0	0	0	0	0	0	0
69	Maintenance of Overhead Lines	593	1,011	NCP_at_115	455	87	176	213	63	9	7
70	Maintenance of Underground Lines	594	81	NCP_at_115	37	7	14	17	5	1	1
71	Maintenance of Line Transformers	595	0	None	0	0	0	0	0	0	0
72	Maintenance of Street Lights	596	0	None	0	0	0	0	0	0	0
73	Maintenance of Meters	597	0	SUBT-PT-D	0	0	0	0	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	6,105		2,553	472	1,096	1,483	418	55	27
75											

Class Cost of Service Study ($000s)
SUBTRANSMISSION DEMAND - CLASS ALLOCATION

	Account Description	Account No.	SubTransmiss Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**										
77	Supervision	901	0	None	0	0	0	0	0	0	0
78	Meter Reading Expenses	902	0	None	0	0	0	0	0	0	0
79	Customer Records & Collection Exp	903	0	None	0	0	0	0	0	0	0
80	Uncollectible Accounts- Delivery	904	0	None	0	0	0	0	0	0	0
81	Uncollectible Accounts- Commodity	904Com	0	None	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	0	None	0	0	0	0	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0	0
84											
85	Supervision	907	0	None	0	0	0	0	0	0	0
86	Customer Assistance Exp Electric	908-909	0	None	0	0	0	0	0	0	0
85	Customer Assistance Expenses	910	0	None	0	0	0	0	0	0	0
86	Subtotal - Customer Service & Info.	907-913	0		0	0	0	0	0	0	0
87											
88	Total - CUST. ACCT. & SERV. EX	901-919	0		0	0	0	0	0	0	0
89											
90	**C. ADMINISTRATIVE AND GENERAL**										
91	GENERAL EXPENSES										
92	A&G-Salaries	920	1,118	SUBT-LAB-D	460	84	202	279	78	10	4
93	A&G-Office Supplies	921	1,151	SUBT-LAB-D	474	87	208	287	80	10	5
94	A&G-Outside Services Employed	923	230	SUBT-LAB-D	95	17	42	57	16	2	1
95	Property Insurance	924	41	SUBT-PT-D	18	3	7	9	3	0	0
96	Injuries & Damages Insurance	925	270	SUBT-PT-D	119	23	47	59	17	2	2
97	Employee Pensions & Benefits	926	2,780	SUBT-LAB-D	1,144	210	502	694	194	25	11
98	Regulatory Comm Expenses	928	195	RateBase	99	18	32	27	8	10	1
99	A&G-Misc Expenses	930200	154	MWh-Gen	62	11	28	40	11	1	1
100	A&G-Research & Development	930210	5	RateBase	2	0	1	1	0	0	0
101	A&G-Rents	931	556	SUBT-LAB-D	229	42	100	139	39	5	2
101	A&G Maint-General Plant-Elec	935	31	SUBT-LAB-D	13	2	6	8	2	0	0
102	TOTAL A&G EXPENSES	920-932	6,530		2,715	499	1,174	1,599	448	68	27
103											
104	TOTAL OPERATING EXPENSES		12,635		5,268	972	2,270	3,082	867	123	54
105											
106	**II. DEPRECIATION EXPENSE**										
107	Depreciation Expense	403	1,646	SUBT-PT-D	727	138	289	361	105	15	10
108	TOTAL DEPREC. EXPENSE	403	1,646		727	138	289	361	105	15	10
109											

Class Cost of Service Study ($000s)
SUBTRANSMISSION DEMAND - CLASS ALLOCATION

	Account Description	Account No.	SubTransmiss Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**										
111	**A. GENERAL TAXES**										
112	Municipal taxes	408	797	SUBT-PT-D	352	67	140	175	51	7	5
113	Payroll taxes	408	448	SUBT-LAB-D	185	34	81	112	31	4	2
114	Other taxes	408	11	SUBT-PT-D	5	1	2	2	1	0	0
115	Subtotal - General Taxes		1,256		541	102	223	289	83	11	7
116											
117	**B. FEDERAL / STATE INCOME TAXES**										
118	Amort. ITC		(19)	SUBT-PT-D	(9)	(2)	(3)	(4)	(1)	(0)	(0)
119	Federal Income Tax Expense		(122)	RATEBASE	(62)	(11)	(20)	(17)	(5)	(6)	(0)
120	Subtotal - Federal / State Income Ta:	409-411	(142)		(71)	(13)	(24)	(21)	(6)	(7)	(1)
121											
122	TOTAL TAXES	408-411	1,115		471	89	199	268	77	5	6
123											
124	**C. OTHER**										
125	Merger / Synergy Benefits		(33)	RATEBASE	(17)	(3)	(5)	(5)	(1)	(2)	(0)
126	Amortization of Loss on Reacq Debt		27	SUBT-PT-D	12	2	5	6	2	0	0
127	Interest on Customer deposits		0	None	0	0	0	0	0	0	0
128	Subtotal- Other		(5)		(4)	(1)	(1)	1	0	(1)	0
129											
130	TOTAL EXPENSES		15,390		6,461	1,197	2,758	3,713	1,049	142	71
131											
132	**IV. OPERATING REVENUES at Current Rates**										
133	Distribution charge revenue	440	15,027	Total_Del_Rev	7,890	1,621	2,212	2,320	354	616	14
134	Forfeited discounts	450-451	0	None	0	0	0	0	0	0	0
135	Rent from Utility property	451Misc	94	NCP_at_115	42	8	16	20	6	1	1
136	Other revenue	454	206	Total_Del_Rev	108	22	30	32	5	8	0
137	Total Operating Revenues		15,327		8,040	1,651	2,258	2,371	365	626	15
138											
139	TOTAL EXPENSES		15,390		6,461	1,197	2,758	3,713	1,049	142	71
140											
141	**V. NET INCOME at Current Rates**		(64)		1,579	454	(499)	(1,341)	(684)	484	(56)
142											

Class Cost of Service Study ($000s)
SUBTRANSMISSION DEMAND - CLASS ALLOCATION

	Account Description	Account No.	SubTransmiss Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**										
144	OPERATING REVENUES										
145	Utility Revenues	440-446	15,027		7,890	1,621	2,212	2,320	354	616	14
146	Other Operating Revenues	450-456	300		150	30	47	52	11	9	1
147	Total Operating Revenues		15,327		8,040	1,651	2,258	2,371	365	626	15
148											
149	OPERATING EXPENSES										
150	Distribution	580-599	6,105		2,553	472	1,096	1,483	418	55	27
151	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0
152	Admin & General	920-932	6,530		2,715	499	1,174	1,599	448	68	27
153	Total Operating Expenses		12,635		5,268	972	2,270	3,082	867	123	54
154											
155	Depreciation Expense	403	1,646		727	138	289	361	105	15	10
156	Taxes Other Than Income Tax / Oth	408	1,251		537	101	222	291	83	10	7
157	INCOME BEFORE INCOME TAX		(206)		1,508	441	(523)	(1,362)	(690)	477	(57)
158	Income Taxes	409-411	(142)		(71)	(13)	(24)	(21)	(6)	(7)	(1)
159	NET INCOME		(64)		1,579	454	(499)	(1,341)	(684)	484	(56)
160											
161	RATE BASE		23,898		10,591	2,011	4,189	5,212	1,523	218	155
162	Return on Rate Base										
163											
164	**REVENUE REQUIREMENTS**										
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		23,898		10,591	2,011	4,189	5,212	1,523	218	155
167											
168	Operating expenses		12,635		5,268	972	2,270	3,082	867	123	54
169	Additional uncollectibles expense		0	None	0	0	0	0	0	0	0
170	Depreciation expense		1,646		727	138	289	361	105	15	10
171	General taxes / Other		1,251		537	101	222	291	83	10	7
172	Subtotal- Operating Costs to recover		15,532		6,532	1,210	2,781	3,734	1,055	148	71
173											
174	Target Return on Rate Base- After ta		2,146		951	181	376	468	137	20	14
175											
176	Income taxes to recover		728		322	61	128	159	46	7	5
177											
178	**TOTAL REVENUE REQUIREMENT**		18,406		7,806	1,452	3,285	4,360	1,239	174	90
179											
180	Revenue at Current rates		15,327		8,040	1,651	2,258	2,371	365	626	15
181	Revenue Excess (Deficiency)		(3,079)		234	199	(1,026)	(1,989)	(873)	451	(75)

Class Cost of Service Study ($000s)
PRIMARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Primary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	**I. ELECTRIC PLANT IN SERVICE**										
2	**A. PRODUCTION PLANT**										
3	Production Plant		0	None	0	0	0	0	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	0		0	0	0	0	0	0	0
5											
6	**B. DISTRIBUTION PLANT**										
7	Land and Land Rights	360	9,586	NCP_at_Pri	4,315	825	1,669	2,025	598	87	68
8	Structures and Improvements	361	7,196	NCP_at_Pri	3,239	619	1,253	1,520	449	65	51
9	Station Equipment	362	171,209	NCP_at_Pri	77,067	14,728	29,811	36,159	10,685	1,551	1,208
10	Poles, Towers and Fixtures	364	109,288	NCP_at_Pri	49,194	9,401	19,029	23,081	6,821	990	771
11	Overhead Conductors and Devices	365	182,924	NCP_at_Pri	82,340	15,736	31,850	38,633	11,417	1,658	1,291
12	Underground Conduit	366	49,988	NCP_at_Pri	22,501	4,300	8,704	10,557	3,120	453	353
13	Underground Conductors & Devices	367	113,255	NCP_at_Pri	50,979	9,742	19,720	23,919	7,068	1,026	799
14	Line Transformers	368	160,299	Xfmr (DIV 18-1)	87,603	16,735	33,695	17,184	5,081	0	0
15	Services	369	0	None	0	0	0	0	0	0	0
16	Meters	370	0	None	0	0	0	0	0	0	0
17	Installations on Cust. Prem./ARO	371/374	0	None	0	0	0	0	0	0	0
18	Street Lighting & Signal Systems	373	0	NCP_at_Pri	0	0	0	0	0	0	0
19	Subtotal - DISTRIBUTION PLANT	360-373	803,746		377,239	72,086	145,731	153,079	45,240	5,831	4,541
20											
21	**C. GENERAL PLANT**										
22	Land and Land Rights	389	380	PRI-LAB-D	172	33	66	80	24	3	3
23	Structures and Improvements	390	9,403	PRI-LAB-D	4,247	812	1,643	1,971	582	84	65
24	Office Furniture and Equipment	391	343	PRI-LAB-D	155	30	60	72	21	3	2
25	Passenger Cars - Transp Equipment	392	258	PRI-LAB-D	117	22	45	54	16	2	2
26	Stores Equipment	393	181	PRI-LAB-D	82	16	32	38	11	2	1
27	Tools, Shop & Garage Equipment	394	1,070	PRI-LAB-D	483	92	187	224	66	10	7
28	Laboratory Equipment	395	761	PRI-LAB-D	344	66	133	160	47	7	5
29	Communications Equipment	396	10,299	PRI-LAB-D	4,651	889	1,799	2,159	638	92	72
30	Miscellaneous Equipment	397/399.1	49	PRI-LAB-D	22	4	9	10	3	0	0
31	Subtotal - GENERAL PLANT	389-399	22,747		10,273	1,963	3,973	4,767	1,409	203	158
32											
33	**TOTAL UTILITY PLANT**		826,492		387,512	74,049	149,704	157,846	46,649	6,033	4,699
34											
35	**II. DEPRECIATION RESERVE**										
36	Production	108.3	0	None	0	0	0	0	0	0	0
37	Distribution	108.5	(335,032)	PRI-PT-D	(157,084)	(30,017)	(60,685)	(63,985)	(18,910)	(2,446)	(1,905)
38	General	108.6	(9,823)	PRI-LAB-D	(4,437)	(848)	(1,716)	(2,059)	(608)	(88)	(68)
39	TOTAL DEPREC. RESERVE	108	(344,855)		(161,521)	(30,865)	(62,401)	(66,044)	(19,518)	(2,533)	(1,973)

Class Cost of Service Study ($000s)
PRIMARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Primary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40											
41	**III. OTHER RATE BASE ITEMS**										
42	Property Held for Future Use	131	137	PRI-PT-D	64	12	25	26	8	1	1
43	Contributions in Aid of Construction	255	(69)	PRI-PT-D	(32)	(6)	(13)	(13)	(4)	(1)	(0)
44	Materials and Supplies	255	4,276	PRI-PT-D	2,005	383	775	817	241	31	24
45	Loss on Reacquired Debt	255	3,079	PRI-PT-D	1,443	276	558	588	174	22	18
45	Cash Working Capital		7,652	PRI-EXP-D	3,474	661	1,338	1,579	465	86	50
46	Accumulated Deferred FIT	154	(75,820)	PRI-PT-D	(35,549)	(6,793)	(13,733)	(14,480)	(4,279)	(553)	(431)
47	Customer Deposits	182	0	None	0	0	0	0	0	0	0
48	Injuries and Damages Reserve		(3,193)	PRI-PT-D	(1,497)	(286)	(578)	(610)	(180)	(23)	(18)
49	Total - OTHER RATE BASE ITEM	131-283	(63,938)		(30,092)	(5,753)	(11,629)	(12,094)	(3,576)	(437)	(357)
50											
51	**TOTAL RATE BASE**		417,699		195,899	37,431	75,674	79,708	23,555	3,063	2,369
52											
53	**I. OPERATING AND MAINTENANCE EXPENSES**										
54	**A. DISTRIBUTION EXPENSE**										
55	Purchased Power- Borderline	555	0	PRI-LAB-D	0	0	0	0	0	0	0
56	Operation Supervision & Engineerin	580	738	PRI-DxLAB-D	333	64	129	155	46	7	5
57	Load Dispatching	581	0	None	0	0	0	0	0	0	0
58	Station Expenses	582	3,174	NCP_at_PRI	1,429	273	553	670	198	29	22
59	Overhead Line Expenses	583	3,445	NCP_at_PRI	1,551	296	600	728	215	31	24
60	Underground Line Expenses	584	1,540	NCP_at_PRI	693	132	268	325	96	14	11
61	Street Light and Signal Systems	585	0	None	0	0	0	0	0	0	0
62	Meter Expenses	586	0	None	0	0	0	0	0	0	0
63	Customer Installation Expenses	587	926	NCP_at_PRI	417	80	161	195	58	8	7
64	Misc. Distribution Expenses	588	6,227	PRI-DxLAB-D	2,812	537	1,088	1,305	386	56	43
65	Rents	589	75	PRI-PT-D	35	7	14	14	4	1	0
66	Maint Supervision & Engineering	590	21	PRI-DxLAB-D	9	2	4	4	1	0	0
67	Maint of Structures	591	25	NCP_at_PRI	11	2	4	5	2	0	0
68	Maintenance of Station Equipment	592	3,332	NCP_at_PRI	1,500	287	580	704	208	30	24
69	Maintenance of Overhead Lines	593	12,123	NCP_at_PRI	5,457	1,043	2,111	2,560	757	110	86
70	Maintenance of Underground Lines	594	912	NCP_at_PRI	411	78	159	193	57	8	6
71	Maintenance of Line Transformers	595	263	Xfmr (DIV 18-1)	144	27	55	28	8	0	0
72	Maintenance of Street Lights	596	0	None	0	0	0	0	0	0	0
73	Maintenance of Meters	597	0	PRI-PT-D	0	0	0	0	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	32,802		14,802	2,829	5,725	6,887	2,035	294	229
75											

Class Cost of Service Study ($000s)
PRIMARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Primary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**										
77	Supervision	901	0	None	0	0	0	0	0	0	0
78	Meter Reading Expenses	902	0	None	0	0	0	0	0	0	0
79	Customer Records & Collection Exp	903	0	None	0	0	0	0	0	0	0
80	Uncollectible Accounts- Delivery	904	0	None	0	0	0	0	0	0	0
81	Uncollectible Accounts- Commodity	904Com	0	None	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	0	None	0	0	0	0	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0	0
84											
85	Supervision	907	0	None	0	0	0	0	0	0	0
86	Customer Assistance Exp Electric	908-909	0	None	0	0	0	0	0	0	0
85	Customer Assistance Expenses	910	0	None	0	0	0	0	0	0	0
86	Subtotal - Customer Service & Info.	907-913	0		0	0	0	0	0	0	0
87											
88	Total - CUST. ACCT. & SERV. EX	901-919	0		0	0	0	0	0	0	0
89											
90	**C. ADMINISTRATIVE AND GENERAL**										
91	GENERAL EXPENSES										
92	A&G-Salaries	920	3,686	PRI-LAB-D	1,664	318	644	772	228	33	26
93	A&G-Office Supplies	921	3,795	PRI-LAB-D	1,714	328	663	795	235	34	26
94	A&G-Outside Services Employed	923	760	PRI-LAB-D	343	66	133	159	47	7	5
95	Property Insurance	924	695	PRI-PT-D	326	62	126	133	39	5	4
96	Injuries & Damages Insurance	925	4,562	PRI-PT-D	2,139	409	826	871	257	33	26
97	Employee Pensions & Benefits	926	9,169	PRI-LAB-D	4,141	791	1,602	1,922	568	82	64
98	Regulatory Comm Expenses	928	3,403	RateBase	1,727	314	560	471	137	179	14
99	A&G-Misc Expenses	930200	2,595	MWh-Gen	1,046	190	472	669	185	24	8
100	A&G-Research & Development	930210	84	RateBase	42	8	14	12	3	4	0
101	A&G-Rents	931	1,834	PRI-LAB-D	828	158	320	384	114	16	13
101	A&G Maint-General Plant-Elec	935	101	PRI-LAB-D	45	9	18	21	6	1	1
102	TOTAL A&G EXPENSES	920-932	30,683		14,017	2,653	5,378	6,210	1,821	418	187
103											
104	TOTAL OPERATING EXPENSES		63,485		28,819	5,482	11,103	13,097	3,856	712	416
105											
106	**II. DEPRECIATION EXPENSE**										
107	Depreciation Expense	403	27,801	PRI-PT-D	13,035	2,491	5,036	5,309	1,569	203	158
108	TOTAL DEPREC. EXPENSE	403	27,801		13,035	2,491	5,036	5,309	1,569	203	158
109											

Class Cost of Service Study ($000s)
PRIMARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Primary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**										
111	**A. GENERAL TAXES**										
112	Municipal taxes	408	13,466	PRI-PT-D	6,314	1,206	2,439	2,572	760	98	77
113	Payroll taxes	408	1,479	PRI-LAB-D	668	128	258	310	92	13	10
114	Other taxes	408	184	PRI-PT-D	86	17	33	35	10	1	1
115	Subtotal - General Taxes		15,129	None	7,068	1,351	2,731	2,917	862	113	88
116											
117	**B. FEDERAL / STATE INCOME TAXES**										
118	Amort. ITC		(327)	PRI-PT-D	(153)	(29)	(59)	(62)	(18)	(2)	(2)
119	Federal Income Tax Expense		(2,141)	RATEBASE	(1,087)	(198)	(353)	(296)	(86)	(113)	(9)
120	Subtotal - Federal / State Income Ta:	409-411	(2,468)		(1,240)	(227)	(412)	(359)	(105)	(115)	(11)
121											
122	TOTAL TAXES	408-411	12,661		5,828	1,124	2,319	2,558	757	(2)	77
123											
124	**C. OTHER**										
125	Merger / Synergy Benefits		(569)	RATEBASE	(289)	(53)	(94)	(79)	(23)	(30)	(2)
126	Amortization of Loss on Reacq Debt		460	PRI-PT-D	216	41	83	88	26	3	3
127	Interest on Customer deposits		0	None	0	0	0	0	0	0	0
128	Subtotal- Other		(109)		(73)	(11)	(10)	9	3	(27)	0
129											
130	TOTAL EXPENSES		103,837		47,609	9,085	18,447	20,974	6,185	886	651
131											
132	**IV. OPERATING REVENUES at Current Rates**										
133	Distribution charge revenue	440	110,851	Total_Del_Rev	58,202	11,957	16,316	17,113	2,614	4,546	103
134	Forfeited discounts	450-451	0	None	0	0	0	0	0	0	0
135	Rent from Utility property	451Misc	1,560	NCP_at_Pri	702	134	272	329	97	14	11
136	Other revenue	454	1,517	Total_Del_Rev	796	164	223	234	36	62	1
137	Total Operating Revenues		113,928		59,700	12,255	16,811	17,677	2,747	4,622	116
138											
139	TOTAL EXPENSES		103,837		47,609	9,085	18,447	20,974	6,185	886	651
140											
141	**V. NET INCOME at Current Rates**		10,091		12,091	3,170	(1,636)	(3,297)	(3,438)	3,736	(536)
142											

Class Cost of Service Study ($000s)
PRIMARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Primary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**										
144	OPERATING REVENUES										
145	Utility Revenues	440-446	110,851		58,202	11,957	16,316	17,113	2,614	4,546	103
146	Other Operating Revenues	450-456	3,077		1,499	298	495	564	133	76	12
147	Total Operating Revenues		113,928		59,700	12,255	16,811	17,677	2,747	4,622	116
148											
149	OPERATING EXPENSES										
150	Distribution	580-599	32,802		14,802	2,829	5,725	6,887	2,035	294	229
151	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0
152	Admin & General	920-932	30,683		14,017	2,653	5,378	6,210	1,821	418	187
153	Total Operating Expenses		63,485		28,819	5,482	11,103	13,097	3,856	712	416
154											
155	Depreciation Expense	403	27,801		13,035	2,491	5,036	5,309	1,569	203	158
156	Taxes Other Than Income Tax / Oth	408	15,020		6,995	1,339	2,720	2,926	865	86	88
157	INCOME BEFORE INCOME TAX		7,622		10,851	2,943	(2,048)	(3,656)	(3,543)	3,621	(546)
158	Income Taxes	409-411	(2,468)		(1,240)	(227)	(412)	(359)	(105)	(115)	(11)
159	NET INCOME		10,091		12,091	3,170	(1,636)	(3,297)	(3,438)	3,736	(536)
160											
161	RATE BASE		417,699		195,899	37,431	75,674	79,708	23,555	3,063	2,369
162	Return on Rate Base										
163											
164	**REVENUE REQUIREMENTS**										
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		417,699		195,899	37,431	75,674	79,708	23,555	3,063	2,369
167											
168	Operating expenses		63,485		28,819	5,482	11,103	13,097	3,856	712	416
169	Additional uncollectibles expense		0	None	0	0	0	0	0	0	0
170	Depreciation expense		27,801		13,035	2,491	5,036	5,309	1,569	203	158
171	General taxes / Other		15,020		6,995	1,339	2,720	2,926	865	86	88
172	Subtotal- Operating Costs to recover		106,305		48,849	9,312	18,859	21,333	6,290	1,001	662
173											
174	Target Return on Rate Base- After ta		37,509		17,592	3,361	6,796	7,158	2,115	275	213
175											
176	Income taxes to recover		12,719		5,965	1,140	2,304	2,427	717	93	72
177											
178	**TOTAL REVENUE REQUIREMENT**		156,534		72,406	13,813	27,959	30,917	9,123	1,370	947
179											
180	Revenue at Current rates		113,928		59,700	12,255	16,811	17,677	2,747	4,622	116
181	Revenue Excess (Deficiency)		(42,606)		(12,706)	(1,558)	(11,148)	(13,241)	(6,375)	3,253	(831)

Class Cost of Service Study ($000s)
SECONDARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential A16 / A60	Small C&I C6	General C&I G2 / E40	200 kW Demand B32 / G32	3000 kW Demand B62 / G62	Lighting S10 / S14	Propulsion X1
1	**I. ELECTRIC PLANT IN SERVICE**										
2	**A. PRODUCTION PLANT**										
3	Production Plant		0	None	0	0	0	0	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	0	None	0	0	0	0	0	0	0
5											
6	**B. DISTRIBUTION PLANT**										
7	Land and Land Rights	360	0	None	0	0	0	0	0	0	0
8	Structures and Improvements	361	0	None	0	0	0	0	0	0	0
9	Station Equipment	362	0	None	0	0	0	0	0	0	0
10	Poles, Towers and Fixtures	364	69,354	NCP_at_Sec	43,499	8,313	16,666	0	0	876	0
11	Overhead Conductors and Devices	365	64,837	NCP_at_Sec	40,666	7,772	15,581	0	0	819	0
12	Underground Conduit	366	8,127	NCP_at_Sec	5,097	974	1,953	0	0	103	0
13	Underground Conductors & Devices	367	12,586	NCP_at_Sec	7,894	1,509	3,025	0	0	159	0
14	Line Transformers	368	0	Xfmr (DIV 18-1)	0	0	0	0	0	0	0
15	Services	369	0	None	0	0	0	0	0	0	0
16	Meters	370	0	None	0	0	0	0	0	0	0
17	Installations on Cust. Prem./ARO	371/374	0	None	0	0	0	0	0	0	0
18	Street Lighting & Signal Systems	373	0	None	0	0	0	0	0	0	0
19	Subtotal - DISTRIBUTION PLANT	360-373	154,904		97,157	18,567	37,224	0	0	1,956	0
20											
21	**C. GENERAL PLANT**										
22	Land and Land Rights	389	110	SEC-LAB-D	69	13	26	0	0	1	0
23	Structures and Improvements	390	2,720	SEC-LAB-D	1,706	326	654	0	0	34	0
24	Office Furniture and Equipment	391	99	SEC-LAB-D	62	12	24	0	0	1	0
25	Passenger Cars - Transp Equipment	392	75	SEC-LAB-D	47	9	18	0	0	1	0
26	Stores Equipment	393	52	SEC-LAB-D	33	6	13	0	0	1	0
27	Tools, Shop & Garage Equipment	394	310	SEC-LAB-D	194	37	74	0	0	4	0
28	Laboratory Equipment	395	220	SEC-LAB-D	138	26	53	0	0	3	0
29	Communications Equipment	396	2,979	SEC-LAB-D	1,869	357	716	0	0	38	0
30	Miscellaneous Equipment	397/399.1	14	SEC-LAB-D	9	2	3	0	0	0	0
31	Subtotal - GENERAL PLANT	389-399	6,580		4,127	789	1,581	0	0	83	0
32											
33	**TOTAL UTILITY PLANT**		161,484		101,284	19,356	38,805	0	0	2,039	0
34											
35	**II. DEPRECIATION RESERVE**										
36	Production	108.3	0	None	0	0	0	0	0	0	0
37	Distribution	108.5	(64,570)	SEC-PT-D	(40,499)	(7,739)	(15,516)	0	0	(815)	0
38	General	108.6	(2,842)	SEC-LAB-D	(1,782)	(341)	(683)	0	0	(36)	0
39	TOTAL DEPREC. RESERVE	108	(67,411)		(42,281)	(8,080)	(16,199)	0	0	(851)	0

Class Cost of Service Study ($000s)
SECONDARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40											
41	**III. OTHER RATE BASE ITEMS**										
42	Property Held for Future Use	131	27	SEC-PT-D	17	3	6	0	0	0	0
43	Contributions in Aid of Construction	255	(13)	SEC-PT-D	(8)	(2)	(3)	0	0	(0)	0
44	Materials and Supplies	255	829	SEC-PT-D	520	99	199	0	0	10	0
45	Loss on Reacquired Debt	255	597	SEC-PT-D	374	72	143	0	0	8	0
45	Cash Working Capital		2,153	SEC-EXP-D	1,327	253	508	27	8	30	1
46	Accumulated Deferred FIT	154	(14,814)	SEC-PT-D	(9,291)	(1,776)	(3,560)	0	0	(187)	0
47	Customer Deposits	182	0	None	0	0	0	0	0	0	0
48	Injuries and Damages Reserve		(624)	SEC-PT-D	(391)	(75)	(150)	0	0	(8)	0
49	Total - OTHER RATE BASE ITEM	131-283	(11,846)		(7,453)	(1,425)	(2,856)	27	8	(146)	1
50											
51	**TOTAL RATE BASE**		82,227		51,550	9,851	19,750	27	8	1,041	1
52											
53	**I. OPERATING AND MAINTENANCE EXPENSES**										
54	**A. DISTRIBUTION EXPENSE**										
55	Purchased Power- Borderline	555	0	None	0	0	0	0	0	0	0
56	Operation Supervision & Engineerin	580	214	SEC-DxLAB-D	134	26	51	0	0	3	0
57	Load Dispatching	581	0	None	0	0	0	0	0	0	0
58	Station Expenses	582	0	None	0	0	0	0	0	0	0
59	Overhead Line Expenses	583	1,582	NCP_at_Sec	992	190	380	0	0	20	0
60	Underground Line Expenses	584	171	NCP_at_Sec	107	21	41	0	0	2	0
61	Street Light and Signal Systems	585	0	None	0	0	0	0	0	0	0
62	Meter Expenses	586	0	None	0	0	0	0	0	0	0
63	Customer Installation Expenses	587	587	NCP_at_Sec	368	70	141	0	0	7	0
64	Misc. Distribution Expenses	588	1,801	SEC-DxLAB-D	1,130	216	433	0	0	23	0
65	Rents	589	14	SEC-PT-D	9	2	3	0	0	0	0
66	Maint Supervision & Engineering	590	6	SEC-DxLAB-D	4	1	1	0	0	0	0
67	Maint of Structures	591	0	None	0	0	0	0	0	0	0
68	Maintenance of Station Equipment	592	0	None	0	0	0	0	0	0	0
69	Maintenance of Overhead Lines	593	5,567	NCP_at_Sec	3,492	667	1,338	0	0	70	0
70	Maintenance of Underground Lines	594	101	NCP_at_Sec	64	12	24	0	0	1	0
71	Maintenance of Line Transformers	595	0	Xfmr (DIV 18-1)	0	0	0	0	0	0	0
72	Maintenance of Street Lights	596	0	None	0	0	0	0	0	0	0
73	Maintenance of Meters	597	0	SEC-PT-D	0	0	0	0	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	10,045		6,300	1,204	2,414	0	0	127	0
75											

Class Cost of Service Study ($000s)
SECONDARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**										
77	Supervision	901	0	None	0	0	0	0	0	0	0
78	Meter Reading Expenses	902	0	None	0	0	0	0	0	0	0
79	Customer Records & Collection Exp	903	0	None	0	0	0	0	0	0	0
80	Uncollectible Accounts- Delivery	904	0	None	0	0	0	0	0	0	0
81	Uncollectible Accounts- Commodity	904Com	0	None	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	0	None	0	0	0	0	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0	0
84											
85	Supervision	907	0	None	0	0	0	0	0	0	0
86	Customer Assistance Exp Electric	908-909	0	None	0	0	0	0	0	0	0
85	Customer Assistance Expenses	910	0	None	0	0	0	0	0	0	0
86	Subtotal - Customer Service & Info.	907-913	0		0	0	0	0	0	0	0
87											
88	Total - CUST. ACCT. & SERV. EX	901-919	0		0	0	0	0	0	0	0
89											
90	**C. ADMINISTRATIVE AND GENERAL**										
91	GENERAL EXPENSES										
92	A&G-Salaries	920	1,066	SEC-LAB-D	669	128	256	0	0	13	0
93	A&G-Office Supplies	921	1,098	SEC-LAB-D	689	132	264	0	0	14	0
94	A&G-Outside Services Employed	923	220	SEC-LAB-D	138	26	53	0	0	3	0
95	Property Insurance	924	136	SEC-PT-D	85	16	33	0	0	2	0
96	Injuries & Damages Insurance	925	891	SEC-PT-D	559	107	214	0	0	11	0
97	Employee Pensions & Benefits	926	2,653	SEC-LAB-D	1,664	318	637	0	0	33	0
98	Regulatory Comm Expenses	928	670	RateBase	340	62	110	93	27	35	3
99	A&G-Misc Expenses	930200	507	MWh-Gen	204	37	92	131	36	5	2
100	A&G-Research & Development	930210	16	RateBase	8	2	3	2	1	1	0
101	A&G-Rents	931	531	SEC-LAB-D	333	64	128	0	0	7	0
101	A&G Maint-General Plant-Elec	935	29	SEC-LAB-D	18	3	7	0	0	0	0
102	TOTAL A&G EXPENSES	920-932	7,817		4,707	894	1,797	226	64	124	4
103											
104	TOTAL OPERATING EXPENSES		17,861		11,007	2,098	4,211	226	64	251	4
105											
106	**II. DEPRECIATION EXPENSE**										
107	Depreciation Expense	403	5,432	SEC-PT-D	3,407	651	1,305	0	0	69	0
108	TOTAL DEPREC. EXPENSE	403	5,432		3,407	651	1,305	0	0	69	0
109											

Class Cost of Service Study ($000s)
SECONDARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**										
111	**A. GENERAL TAXES**										
112	Municipal taxes	408	2,631	SEC-PT-D	1,650	315	632	0	0	33	0
113	Payroll taxes	408	428	SEC-LAB-D	268	51	103	0	0	5	0
114	Other taxes	408	36	SEC-PT-D	23	4	9	0	0	0	0
115	Subtotal - General Taxes		3,095	None	1,941	371	744	0	0	39	0
116											
117	**B. FEDERAL / STATE INCOME TAXES**										
118	Amort. ITC		(64)	SEC-PT-D	(40)	(8)	(15)	0	0	(1)	0
119	Federal Income Tax Expense		(421)	RATEBASE	(214)	(39)	(69)	(58)	(17)	(22)	(2)
120	Subtotal - Federal / State Income Ta:	409-411	(485)		(254)	(47)	(85)	(58)	(17)	(23)	(2)
121											
122	TOTAL TAXES	408-411	2,609		1,687	324	659	(58)	(17)	16	(2)
123											
124	**C. OTHER**										
125	Merger / Synergy Benefits		(111)	RATEBASE	(57)	(10)	(18)	(15)	(4)	(6)	(0)
126	Amortization of Loss on Reacq Debt		90	SEC-PT-D	56	11	22	0	0	1	0
127	Interest on Customer deposits		0	None	0	0	0	0	0	0	0
128	Subtotal- Other		(22)		(0)	0	3	(15)	(4)	(5)	(0)
129											
130	TOTAL EXPENSES		25,881		16,101	3,074	6,178	152	42	331	2
131											
132	**IV. OPERATING REVENUES at Current Rates**										
133	Distribution charge revenue	440	23,349	Total_Del_Rev	12,259	2,519	3,437	3,605	551	958	22
134	Forfeited discounts	450-451	0	None	0	0	0	0	0	0	0
135	Rent from Utility property	451Misc	990	NCP_at_Sec	621	119	238	0	0	12	0
136	Other revenue	454	320	Total_Del_Rev	168	34	47	49	8	13	0
137	Total Operating Revenues		24,659		13,048	2,672	3,722	3,654	558	983	22
138											
139	TOTAL EXPENSES		25,881		16,101	3,074	6,178	152	42	331	2
140											
141	**V. NET INCOME at Current Rates**		(1,222)		(3,053)	(403)	(2,457)	3,502	516	652	20
142											

Class Cost of Service Study ($000s)
SECONDARY DEMAND - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**										
144	OPERATING REVENUES										
145	Utility Revenues	440-446	23,349		12,259	2,519	3,437	3,605	551	958	22
146	Other Operating Revenues	450-456	1,309		789	153	285	49	8	26	0
147	Total Operating Revenues		24,659		13,048	2,672	3,722	3,654	558	983	22
148											
149	OPERATING EXPENSES										
150	Distribution	580-599	10,045		6,300	1,204	2,414	0	0	127	0
151	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0
152	Admin & General	920-932	7,817		4,707	894	1,797	226	64	124	4
153	Total Operating Expenses		17,861		11,007	2,098	4,211	226	64	251	4
154											
155	Depreciation Expense	403	5,432		3,407	651	1,305	0	0	69	0
156	Taxes Other Than Income Tax / Oth	408	3,073		1,941	371	747	(15)	(4)	34	(0)
157	INCOME BEFORE INCOME TAX		(1,708)		(3,307)	(449)	(2,541)	3,444	499	629	18
158	Income Taxes	409-411	(485)		(254)	(47)	(85)	(58)	(17)	(23)	(2)
159	NET INCOME		(1,222)		(3,053)	(403)	(2,457)	3,502	516	652	20
160											
161	RATE BASE		82,227		51,550	9,851	19,750	27	8	1,041	1
162	Return on Rate Base										
163											
164	**REVENUE REQUIREMENTS**										
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		82,227		51,550	9,851	19,750	27	8	1,041	1
167											
168	Operating expenses		17,861		11,007	2,098	4,211	226	64	251	4
169	Additional uncollectibles expense		0	None	0	0	0	0	0	0	0
170	Depreciation expense		5,432		3,407	651	1,305	0	0	69	0
171	General taxes / Other		3,073		1,941	371	747	(15)	(4)	34	(0)
172	Subtotal- Operating Costs to recover		26,366		16,355	3,121	6,263	210	59	354	4
173											
174	Target Return on Rate Base- After ta		7,384		4,629	885	1,774	2	1	94	0
175											
176	Income taxes to recover		2,504		1,570	300	601	1	0	32	0
177											
178	**TOTAL REVENUE REQUIREMENT**		36,254		22,554	4,305	8,638	213	60	479	4
179											
180	Revenue at Current rates		24,659		13,048	2,672	3,722	3,654	558	983	22
181	Revenue Excess (Deficiency)		(11,596)		(9,506)	(1,634)	(4,916)	3,440	498	504	18

Class Cost of Service Study ($000s)

SECONDARY CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	**I. ELECTRIC PLANT IN SERVICE**										
2	**A. PRODUCTION PLANT**										
3	Production Plant		0	None	0	0	0	0	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	0	None	0	0	0	0	0	0	0
5											
6	**B. DISTRIBUTION PLANT**										
7	Land and Land Rights	360	0	None	0	0	0	0	0	0	0
8	Structures and Improvements	361	0	None	0	0	0	0	0	0	0
9	Station Equipment	362	0	None	0	0	0	0	0	0	0
10	Poles, Towers and Fixtures	364	0	None	0	0	0	0	0	0	0
11	Overhead Conductors and Devices	365	0	None	0	0	0	0	0	0	0
12	Underground Conduit	366	0	None	0	0	0	0	0	0	0
13	Underground Conductors & Devices	367	0	None	0	0	0	0	0	0	0
14	Line Transformers	368	0	Xfmr_Cost	0	0	0	0	0	0	0
15	Services	369	72,382	Services_Cost	62,666	8,094	1,537	85	1	0	0
16	Meters	370	0	None	0	0	0	0	0	0	0
17	Installations on Cust. Prem./ARO	371/374	0	None	0	0	0	0	0	0	0
18	Street Lighting & Signal Systems	373	52,924	Light-Fixtures	0	0	0	0	0	52,924	0
19	Subtotal - DISTRIBUTION PLANT	360-373	125,306		62,666	8,094	1,537	85	1	52,924	0
20											
21	**C. GENERAL PLANT**										
22	Land and Land Rights	389	52	SEC-LAB-C	0	0	0	0	0	52	0
23	Structures and Improvements	390	1,298	SEC-LAB-C	0	0	0	0	0	1,298	0
24	Office Furniture and Equipment	391	47	SEC-LAB-C	0	0	0	0	0	47	0
25	Passenger Cars - Transp Equipment	392	36	SEC-LAB-C	0	0	0	0	0	36	0
26	Stores Equipment	393	25	SEC-LAB-C	0	0	0	0	0	25	0
27	Tools, Shop & Garage Equipment	394	148	SEC-LAB-C	0	0	0	0	0	148	0
28	Laboratory Equipment	395	105	SEC-LAB-C	0	0	0	0	0	105	0
29	Communications Equipment	396	1,421	SEC-LAB-C	0	0	0	0	0	1,421	0
30	Miscellaneous Equipment	397/399.1	7	SEC-LAB-C	0	0	0	0	0	7	0
31	Subtotal - GENERAL PLANT	389-399	3,139		0	0	0	0	0	3,139	0
32											
33	**TOTAL UTILITY PLANT**		128,445		62,666	8,094	1,537	85	1	56,063	0
34											
35	**II. DEPRECIATION RESERVE**										
36	Production	108.3	0	None	0	0	0	0	0	0	0
37	Distribution	108.5	(52,232)	SEC-DxPT-C	(26,121)	(3,374)	(641)	(35)	(0)	(22,061)	0
38	General	108.6	(1,356)	SEC-LAB-C	0	0	0	0	0	(1,356)	0
39	TOTAL DEPREC. RESERVE	108	(53,588)		(26,121)	(3,374)	(641)	(35)	(0)	(23,416)	0

Class Cost of Service Study ($000s)
SECONDARY CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40											
41	**III. OTHER RATE BASE ITEMS**										
42	Property Held for Future Use	131	21	SEC-DxPT-C	11	1	0	0	0	9	0
43	Contributions in Aid of Construction	255	(11)	SEC-DxPT-C	(5)	(1)	(0)	(0)	(0)	(5)	0
44	Materials and Supplies	255	671	SEC-DxPT-C	335	43	8	0	0	283	0
45	Loss on Reacquired Debt	255	483	SEC-DxPT-C	242	31	6	0	0	204	0
45	Cash Working Capital		914	SEC-EXP-C	101	16	21	22	6	748	0
46	Accumulated Deferred FIT	154	(11,783)	SEC-PT-C	(5,749)	(743)	(141)	(8)	(0)	(5,143)	0
47	Customer Deposits	182	0	None	0	0	0	0	0	0	0
48	Injuries and Damages Reserve		(496)	SEC-PT-C	(242)	(31)	(6)	(0)	(0)	(217)	0
49	Total - OTHER RATE BASE ITEM	131-283	(10,200)		(5,307)	(683)	(112)	14	6	(4,119)	0
50											
51	**TOTAL RATE BASE**		64,657		31,237	4,037	784	64	6	28,527	0
52											
53	**I. OPERATING AND MAINTENANCE EXPENSES**										
54	**A. DISTRIBUTION EXPENSE**										
55	Purchased Power- Borderline	555	0	SEC-LAB-C	0	0	0	0	0	0	0
56	Operation Supervision & Engineerin	580	102	SEC-DxLAB-C	0	0	0	0	0	102	0
57	Load Dispatching	581	0	None	0	0	0	0	0	0	0
58	Station Expenses	582	0	None	0	0	0	0	0	0	0
59	Overhead Line Expenses	583	0	None	0	0	0	0	0	0	0
60	Underground Line Expenses	584	0	None	0	0	0	0	0	0	0
61	Street Light and Signal Systems	585	530	Light-Fixtures	0	0	0	0	0	530	0
62	Meter Expenses	586	0	None	0	0	0	0	0	0	0
63	Customer Installation Expenses	587	0	None	0	0	0	0	0	0	0
64	Misc. Distribution Expenses	588	859	SEC-DxLAB-C	0	0	0	0	0	859	0
65	Rents	589	12	SEC-DxPT-C	6	1	0	0	0	5	0
66	Maint Supervision & Engineering	590	3	SEC-DxLAB-C	0	0	0	0	0	3	0
67	Maint of Structures	591	0	None	0	0	0	0	0	0	0
68	Maintenance of Station Equipment	592	0	None	0	0	0	0	0	0	0
69	Maintenance of Overhead Lines	593	0	None	0	0	0	0	0	0	0
70	Maintenance of Underground Lines	594	0	None	0	0	0	0	0	0	0
71	Maintenance of Line Transformers	595	0	Xfmr (DIV 18-1)	0	0	0	0	0	0	0
72	Maintenance of Street Lights	596	1,652	Light-Fixtures	0	0	0	0	0	1,652	0
73	Maintenance of Meters	597	0	SEC-DxPT-C	0	0	0	0	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	3,158		6	1	0	0	0	3,151	0
75											

Class Cost of Service Study ($000s)
SECONDARY CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**										
77	Supervision	901	0	None	0	0	0	0	0	0	0
78	Meter Reading Expenses	902	0	None	0	0	0	0	0	0	0
79	Customer Records & Collection Exp	903	0	None	0	0	0	0	0	0	0
80	Uncollectible Accounts- Delivery	904	0	None	0	0	0	0	0	0	0
81	Uncollectible Accounts- Commodity	904Com	0	None	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	0	None	0	0	0	0	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	0		0	0	0	0	0	0	0
84											
85	Supervision	907	0	None	0	0	0	0	0	0	0
86	Customer Assistance Exp Electric	908-909	0	None	0	0	0	0	0	0	0
85	Customer Assistance Expenses	910	0	None	0	0	0	0	0	0	0
86	Subtotal - Customer Service & Info.	907-913	0		0	0	0	0	0	0	0
87											
88	Total - CUST. ACCT. & SERV. EX	901-919	0		0	0	0	0	0	0	0
89											
90	**C. ADMINISTRATIVE AND GENERAL**										
91	GENERAL EXPENSES										
92	A&G-Salaries	920	509	SEC-LAB-C	0	0	0	0	0	509	0
93	A&G-Office Supplies	921	524	SEC-LAB-C	0	0	0	0	0	524	0
94	A&G-Outside Services Employed	923	105	SEC-LAB-C	0	0	0	0	0	105	0
95	Property Insurance	924	108	SEC-PT-C	53	7	1	0	0	47	0
96	Injuries & Damages Insurance	925	709	SEC-PT-C	346	45	8	0	0	309	0
97	Employee Pensions & Benefits	926	1,265	SEC-LAB-C	0	0	0	0	0	1,265	0
98	Regulatory Comm Expenses	928	527	RateBase	267	49	87	73	21	28	2
99	A&G-Misc Expenses	930200	403	MWh-Gen	163	30	73	104	29	4	1
100	A&G-Research & Development	930210	13	RateBase	7	1	2	2	1	1	0
101	A&G-Rents	931	253	SEC-LAB-C	0	0	0	0	0	253	0
101	A&G Maint-General Plant-Elec	935	14	SEC-LAB-C	0	0	0	0	0	14	0
102	TOTAL A&G EXPENSES	920-932	4,429		835	131	172	179	51	3,058	4
103											
104	TOTAL OPERATING EXPENSES		7,587		841	132	172	179	51	6,209	4
105											
106	**II. DEPRECIATION EXPENSE**										
107	Depreciation Expense	403	4,321	SEC-PT-C	2,108	272	52	3	0	1,886	0
108	TOTAL DEPREC. EXPENSE	403	4,321		2,108	272	52	3	0	1,886	0
109											

Class Cost of Service Study ($000s)
SECONDARY CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**										
111	**A. GENERAL TAXES**										
112	Municipal taxes	408	2,093	SEC-PT-C	1,021	132	25	1	0	913	0
113	Payroll taxes	408	204	SEC-LAB-C	0	0	0	0	0	204	0
114	Other taxes	408	29	SEC-PT-C	14	2	0	0	0	13	0
115	Subtotal - General Taxes		2,325		1,035	134	25	1	0	1,130	0
116											
117	**B. FEDERAL / STATE INCOME TAXES**										
118	Amort. ITC		(51)	SEC-PT-C	(25)	(3)	(1)	(0)	(0)	(22)	0
119	Federal Income Tax Expense		(331)	RATEBASE	(168)	(31)	(55)	(46)	(13)	(17)	(1)
120	Subtotal - Federal / State Income Ta:	409-411	(382)		(193)	(34)	(55)	(46)	(13)	(40)	(1)
121											
122	TOTAL TAXES	408-411	1,943		842	100	(30)	(44)	(13)	1,090	(1)
123											
124	**C. OTHER**										
125	Merger / Synergy Benefits		(89)	RATEBASE	(45)	(8)	(15)	(12)	(4)	(5)	(0)
126	Amortization of Loss on Reacq Debt		71	SEC-PT-C	35	5	1	0	0	31	0
127	Interest on Customer deposits		0	CustDep	0	0	0	0	0	0	0
128	Subtotal- Other		(17)		(10)	(4)	(14)	(12)	(4)	27	(0)
129											
130	TOTAL EXPENSES		13,834		3,781	500	180	125	34	9,212	2
131					13,834						
132	**IV. OPERATING REVENUES at Current Rates**										
133	Distribution charge revenue	440	18,572	Total_Del_Rev	9,751	2,003	2,734	2,867	438	762	17
134	Forfeited discounts	450-451	0	None	0	0	0	0	0	0	0
135	Rent from Utility property	451Misc	0	None	0	0	0	0	0	0	0
136	Other revenue	454	254	Total_Del_Rev	133	27	37	39	6	10	0
137	Total Operating Revenues		18,826		9,885	2,031	2,771	2,906	444	772	18
138											
139	TOTAL EXPENSES		13,834		3,781	500	180	125	34	9,212	2
140											
141	**V. NET INCOME at Current Rates**		4,993		6,104	1,531	2,591	2,781	410	(8,440)	16
142											

Class Cost of Service Study ($000s)
SECONDARY CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**										
144	OPERATING REVENUES										
145	Utility Revenues	440-446	18,572		9,751	2,003	2,734	2,867	438	762	17
146	Other Operating Revenues	450-456	254		133	27	37	39	6	10	0
147	Total Operating Revenues		18,826		9,885	2,031	2,771	2,906	444	772	18
148											
149	OPERATING EXPENSES										
150	Distribution	580-599	3,158		6	1	0	0	0	3,151	0
151	Customer Acctg & Service	901-919	0		0	0	0	0	0	0	0
152	Admin & General	920-932	4,429		835	131	172	179	51	3,058	4
153	Total Operating Expenses		7,587		841	132	172	179	51	6,209	4
154											
155	Depreciation Expense	403	4,321		2,108	272	52	3	0	1,886	0
156	Taxes Other Than Income Tax / Oth	408	2,308		1,025	130	12	(11)	(4)	1,156	(0)
157	INCOME BEFORE INCOME TAX		4,610		5,911	1,497	2,536	2,735	397	(8,479)	14
158	Income Taxes	409-411	(382)		(193)	(34)	(55)	(46)	(13)	(40)	(1)
159	NET INCOME		4,993		6,104	1,531	2,591	2,781	410	(8,440)	16
160											
161	RATE BASE		64,657		31,237	4,037	784	64	6	28,527	0
162	Return on Rate Base										
163											
164	**REVENUE REQUIREMENTS**										
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		64,657		31,237	4,037	784	64	6	28,527	0
167											
168	Operating expenses		7,587		841	132	172	179	51	6,209	4
169	Additional uncollectibles expense		0	None	0	0	0	0	0	0	0
170	Depreciation expense		4,321		2,108	272	52	3	0	1,886	0
171	General taxes / Other		2,308		1,025	130	12	(11)	(4)	1,156	(0)
172	Subtotal- Operating Costs to recover		14,216		3,974	534	235	171	47	9,251	3
173											
174	Target Return on Rate Base- After ta		5,806		2,805	363	70	6	1	2,562	0
175											
176	Income taxes to recover		1,969		951	123	24	2	0	869	0
177											
178	**TOTAL REVENUE REQUIREMENT**		21,991		7,730	1,019	330	179	48	12,682	3
179											
180	Revenue at Current rates		18,826		9,885	2,031	2,771	2,906	444	772	18
181	Revenue Excess (Deficiency)		(3,164)		2,155	1,011	2,441	2,727	396	(11,910)	14

Class Cost of Service Study ($000s)
BILLING CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential A16 / A60	Small C&I C6	General C&I G2 / E40	200 kW Demand B32 / G32	3000 kW Demand B62 / G62	Lighting S10 / S14	Propulsion X1
1	**I. ELECTRIC PLANT IN SERVICE**										
2	**A. PRODUCTION PLANT**										
3	Production Plant		0	None	0	0	0	0	0	0	0
4	Subtotal - PRODUCTION PLANT	350-359	0	None	0	0	0	0	0	0	0
5											
6	**B. DISTRIBUTION PLANT**										
7	Land and Land Rights	360	0	None	0	0	0	0	0	0	0
8	Structures and Improvements	361	0	None	0	0	0	0	0	0	0
9	Station Equipment	362	0	None	0	0	0	0	0	0	0
10	Poles, Towers and Fixtures	364	0	None	0	0	0	0	0	0	0
11	Overhead Conductors and Devices	365	0	None	0	0	0	0	0	0	0
12	Underground Conduit	366	0	None	0	0	0	0	0	0	0
13	Underground Conductors & Devices	367	0	None	0	0	0	0	0	0	0
14	Line Transformers	368	0	None	0	0	0	0	0	0	0
15	Services	369	0	None	0	0	0	0	0	0	0
16	Meters	370	49,671	Meter_Cost	33,809	8,204	5,814	1,834	9	0	0
17	Installations on Cust. Prem./ARO	371/374	165	Meter_Cost	112	27	19	6	0	0	0
18	Street Lighting & Signal Systems	373	0	None	0	0	0	0	0	0	0
19	Subtotal - DISTRIBUTION PLANT	360-373	49,836		33,922	8,231	5,834	1,840	9	0	0
20											
21	**C. GENERAL PLANT**										
22	Land and Land Rights	389	294	BILL-LAB-C	228	37	21	7	0	0	0
23	Structures and Improvements	390	7,259	BILL-LAB-C	5,646	905	511	185	1	11	0
24	Office Furniture and Equipment	391	265	BILL-LAB-C	206	33	19	7	0	0	0
25	Passenger Cars - Transp Equipment	392	199	BILL-LAB-C	155	25	14	5	0	0	0
26	Stores Equipment	393	140	BILL-LAB-C	109	17	10	4	0	0	0
27	Tools, Shop & Garage Equipment	394	826	BILL-LAB-C	643	103	58	21	0	1	0
28	Laboratory Equipment	395	588	BILL-LAB-C	457	73	41	15	0	1	0
29	Communications Equipment	396	7,951	BILL-LAB-C	6,184	991	560	203	1	13	0
30	Miscellaneous Equipment	397/399.1	38	BILL-LAB-C	30	5	3	1	0	0	0
31	Subtotal - GENERAL PLANT	389-399	17,560		13,657	2,189	1,237	448	2	28	0
32											
33	**TOTAL UTILITY PLANT**		67,396		47,579	10,420	7,071	2,288	11	28	0
34											
35	**II. DEPRECIATION RESERVE**										
36	Production	108.3	0	None	0	0	0	0	0	0	0
37	Distribution	108.5	(20,774)	BILL-DxPT-C	(14,140)	(3,431)	(2,432)	(767)	(4)	0	0
38	General	108.6	(7,584)	BILL-LAB-C	(5,898)	(945)	(534)	(194)	(1)	(12)	(0)
39	TOTAL DEPREC. RESERVE	108	(28,357)		(20,038)	(4,376)	(2,966)	(960)	(5)	(12)	(0)

Class Cost of Service Study ($000s)
BILLING CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
40											
41	**III. OTHER RATE BASE ITEMS**										
42	Property Held for Future Use	131	11	BILL-PT-C	8	2	1	0	0	0	0
43	Contributions in Aid of Construction	255	(6)	BILL-DxPT-C	(4)	(1)	(1)	(0)	(0)	0	0
44	Materials and Supplies	255	349	BILL-DxPT-C	237	58	41	13	0	0	0
45	Loss on Reacquired Debt	255	251	BILL-DxPT-C	171	41	29	9	0	0	0
45	Cash Working Capital		5,547	BILL-EXP-C	4,045	719	438	274	36	34	1
46	Accumulated Deferred FIT	154	(6,183)	BILL-PT-C	(4,365)	(956)	(649)	(210)	(1)	(3)	(0)
47	Customer Deposits	182	(3,283)	CustDep	(24)	(1,563)	(1,565)	(131)	0	(0)	0
48	Injuries and Damages Reserve		(260)	BILL-PT-C	(184)	(40)	(27)	(9)	(0)	(0)	(0)
49	Total - OTHER RATE BASE ITEM	131-283	(3,574)		(115)	(1,741)	(1,732)	(53)	36	31	1
50											
51	**TOTAL RATE BASE**		35,465		27,426	4,303	2,372	1,275	42	46	1
52											
53	**I. OPERATING AND MAINTENANCE EXPENSES**										
54	**A. DISTRIBUTION EXPENSE**										
55	Purchased Power- Borderline	555	0	BILL-LAB-C	0	0	0	0	0	0	0
56	Operation Supervision & Engineerin	580	204	BILL-DxLAB-C	139	34	24	8	0	0	0
57	Load Dispatching	581	0	None	0	0	0	0	0	0	0
58	Station Expenses	582	0	None	0	0	0	0	0	0	0
59	Overhead Line Expenses	583	0	None	0	0	0	0	0	0	0
60	Underground Line Expenses	584	0	None	0	0	0	0	0	0	0
61	Street Light and Signal Systems	585	0	None	0	0	0	0	0	0	0
62	Meter Expenses	586	2,842	Meter_Cost	1,934	469	333	105	1	0	0
63	Customer Installation Expenses	587	0	Customers	0	0	0	0	0	0	0
64	Misc. Distribution Expenses	588	1,719	BILL-DxLAB-C	1,170	284	201	63	0	0	0
65	Rents	589	5	BILL-DxPT-C	3	1	1	0	0	0	0
66	Maint Supervision & Engineering	590	6	BILL-DxLAB-C	4	1	1	0	0	0	0
67	Maint of Structures	591	0	None	0	0	0	0	0	0	0
68	Maintenance of Station Equipment	592	0	None	0	0	0	0	0	0	0
69	Maintenance of Overhead Lines	593	0	None	0	0	0	0	0	0	0
70	Maintenance of Underground Lines	594	0	None	0	0	0	0	0	0	0
71	Maintenance of Line Transformers	595	0	None	0	0	0	0	0	0	0
72	Maintenance of Street Lights	596	0	None	0	0	0	0	0	0	0
73	Maintenance of Meters	597	318	BILL-DxPT-C	216	53	37	12	0	0	0
74	Total - OPER. AND MAINT. EXP.	500-599	5,093		3,466	841	596	188	1	0	0
75											

Class Cost of Service Study ($000s)
BILLING CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
76	**B. CUSTOMER ACCOUNTS AND SERVICE**										
77	Supervision	901	1,197	Acct903	1,026	107	39	21	0	4	0
78	Meter Reading Expenses	902	1,626	Meter_Cost	1,107	269	190	60	0	0	0
79	Customer Records & Collection Exp	903	11,449	Acct903	9,813	1,019	373	205	0	39	0
80	Uncollectible Accounts- Delivery	904	4,301	Total_Del_Rev	2,258	464	633	664	101	176	4
81	Uncollectible Accounts- Commodity	904Com	0	Write-Offs-Comm	0	0	0	0	0	0	0
82	Misc Customer Accounts Expenses	905	1,074	Customers	950	103	19	2	0	0	0
83	Subtotal - Customer Accounts Exp.	901-905	19,647		15,154	1,961	1,254	953	102	219	4
84											
85	Supervision	907	88	Acct908	40	38	8	2	0	0	0
86	Customer Assistance Exp Electric	908-909	1,860	Acct908	846	812	160	36	5	1	0
85	Customer Assistance Expenses	910	3,460	Acct910	1,898	341	431	604	166	18	2
86	Subtotal - Customer Service & Info.	907-913	5,408		2,784	1,191	599	642	171	19	2
87											
88	Total - CUST. ACCT. & SERV. EX	901-919	25,055		17,939	3,152	1,853	1,595	273	238	6
89											
90	**C. ADMINISTRATIVE AND GENERAL**										
91	GENERAL EXPENSES										
92	A&G-Salaries	920	2,845	BILL-LAB-C	2,213	355	200	73	0	4	0
93	A&G-Office Supplies	921	2,930	BILL-LAB-C	2,279	365	206	75	0	5	0
94	A&G-Outside Services Employed	923	587	BILL-LAB-C	456	73	41	15	0	1	0
95	Property Insurance	924	57	BILL-PT-C	40	9	6	2	0	0	0
96	Injuries & Damages Insurance	925	372	BILL-PT-C	263	58	39	13	0	0	0
97	Employee Pensions & Benefits	926	7,079	BILL-LAB-C	5,505	882	499	181	1	11	0
98	Regulatory Comm Expenses	928	289	RateBase	147	27	48	40	12	15	1
99	A&G-Misc Expenses	930200	212	MWh-Gen	85	16	38	55	15	2	1
100	A&G-Research & Development	930210	7	RateBase	4	1	1	1	0	0	0
101	A&G-Rents	931	1,416	BILL-LAB-C	1,101	176	100	36	0	2	0
101	A&G Maint-General Plant-Elec	935	78	BILL-LAB-C	60	10	5	2	0	0	0
102	TOTAL A&G EXPENSES	920-932	15,871		12,153	1,971	1,184	491	29	41	2
103											
104	TOTAL OPERATING EXPENSES		46,018		33,558	5,964	3,633	2,274	303	279	8
105											
106	**II. DEPRECIATION EXPENSE**										
107	Depreciation Expense	403	2,267	BILL-PT-C	1,600	351	238	77	0	1	0
108	TOTAL DEPREC. EXPENSE	403	2,267		1,600	351	238	77	0	1	0
109											

Class Cost of Service Study ($000s)
BILLING CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
110	**III. TAXES and OTHER**										
111	**A. GENERAL TAXES**										
112	Municipal taxes	408	1,098	BILL-PT-C	775	170	115	37	0	0	0
113	Payroll taxes	408	1,141	BILL-LAB-C	888	142	80	29	0	2	0
114	Other taxes	408	15	BILL-PT-C	11	2	2	1	0	0	0
115	Subtotal - General Taxes		2,255	None	1,674	314	197	67	0	2	0
116											
117	**B. FEDERAL / STATE INCOME TAXES**										
118	Amort. ITC		(27)	BILL-PT-C	(19)	(4)	(3)	(1)	(0)	(0)	(0)
119	Federal Income Tax Expense		(182)	RATEBASE	(92)	(17)	(30)	(25)	(7)	(10)	(1)
120	Subtotal - Federal / State Income Ta:	409-411	(208)		(111)	(21)	(33)	(26)	(7)	(10)	(1)
121											
122	TOTAL TAXES	408-411	2,046		1,562	293	164	41	(7)	(7)	(1)
123											
124	**C. OTHER**										
125	Merger / Synergy Benefits		(48)	RATEBASE	(25)	(4)	(8)	(7)	(2)	(3)	(0)
126	Amortization of Loss on Reacq Debt		38	BILL-PT-C	26	6	4	1	0	0	0
127	Interest on Customer deposits		75	CustDep	1	36	36	3	0	0	0
128	Subtotal- Other		64		2	37	32	(2)	(2)	(3)	(0)
129											
130	TOTAL EXPENSES		50,396		36,724	6,645	4,067	2,389	294	270	7
131											
132	**IV. OPERATING REVENUES at Current Rates**										
133	Distribution charge revenue	440	47,621	Total_Del_Rev	25,003	5,137	7,009	7,352	1,123	1,953	44
134	Forfeited discounts	450-451	2,230	Write-Offs	1,752	170	174	134	0	1	0
135	Rent from Utility property	451Misc	0	None	0	0	0	0	0	0	0
136	Other revenue	454	652	Total_Del_Rev	342	70	96	101	15	27	1
137	Total Operating Revenues		50,503		27,097	5,377	7,279	7,586	1,138	1,980	45
138											
139	TOTAL EXPENSES		50,396		36,724	6,645	4,067	2,389	294	270	7
140											
141	**V. NET INCOME at Current Rates**		107		(9,627)	(1,268)	3,212	5,197	844	1,710	38
142											

Class Cost of Service Study ($000s)
BILLING CUSTOMER - CLASS ALLOCATION

	Account Description	Account No.	Secondary Dollars	Allocator	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
					A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
143	**SUMMARY REPORT**										
144	OPERATING REVENUES										
145	Utility Revenues	440-446	47,621		25,003	5,137	7,009	7,352	1,123	1,953	44
146	Other Operating Revenues	450-456	2,882		2,094	240	270	234	15	27	1
147	Total Operating Revenues		50,503		27,097	5,377	7,279	7,586	1,138	1,980	45
148											
149	OPERATING EXPENSES										
150	Distribution	580-599	5,093		3,466	841	596	188	1	0	0
151	Customer Acctg & Service	901-919	25,055		17,939	3,152	1,853	1,595	273	238	6
152	Admin & General	920-932	15,871		12,153	1,971	1,184	491	29	41	2
153	Total Operating Expenses		46,018		33,558	5,964	3,633	2,274	303	279	8
154											
155	Depreciation Expense	403	2,267		1,600	351	238	77	0	1	0
156	Taxes Other Than Income Tax / Oth	408	2,319		1,676	351	229	64	(2)	(0)	(0)
157	INCOME BEFORE INCOME TAX		(101)		(9,738)	(1,289)	3,180	5,171	837	1,701	37
158	Income Taxes	409-411	(208)		(111)	(21)	(33)	(26)	(7)	(10)	(1)
159	NET INCOME		107		(9,627)	(1,268)	3,212	5,197	844	1,710	38
160											
161	RATE BASE		35,465		27,426	4,303	2,372	1,275	42	46	1
162	Return on Rate Base										
163											
164	**REVENUE REQUIREMENTS**										
165	Target Rate of Return		8.980%		8.980%	8.980%	8.980%	8.980%	8.980%	8.980%	8.980%
166	Rate Base		35,465		27,426	4,303	2,372	1,275	42	46	1
167											
168	Operating expenses		46,018		33,558	5,964	3,633	2,274	303	279	8
169	Additional uncollectibles expense		719	Write-Offs	565	55	56	43	0	0	0
170	Depreciation expense		2,267		1,600	351	238	77	0	1	0
171	General taxes / Other		2,319		1,676	351	229	64	(2)	(0)	(0)
172	Subtotal- Operating Costs to recover		51,323		37,399	6,720	4,156	2,458	301	280	8
173											
174	Target Return on Rate Base- After ta		3,185		2,463	386	213	114	4	4	0
175											
176	Income taxes to recover		1,080		835	131	72	39	1	1	0
177											
178	**TOTAL REVENUE REQUIREMENT**		55,588		40,697	7,238	4,441	2,612	306	286	8
179											
180	Revenue at Current rates		50,503		27,097	5,377	7,279	7,586	1,138	1,980	45
181	Revenue Excess (Deficiency)		(5,085)		(13,600)	(1,861)	2,838	4,974	832	1,695	37

Class Cost of Service Study ($000s) Allocators Assigned

	Account Description	Account No.	Dollars	Functional Allocator	SubTransmission	Primary Dist	Secondary Dist			Billing
					Demand Allocator	Demand Allocator	Classification Allocator	Demand Allocator	Customer Allocator	Customer Allocator
1	**I. ELECTRIC PLANT IN SERVICE**									
2	**A. PRODUCTION PLANT**									
3	Production Plant		3,127	SUBT	MWh-Gen	-	-	-	-	-
4	Subtotal - PRODUCTION PLANT	350-359	3,127							
5										
6	**B. DISTRIBUTION PLANT**									
7	Land and Land Rights	360	9,586	STATIONS	-	NCP_at_Pri	-	-	-	-
8	Structures and Improvements	361	7,196	STATIONS	-	NCP_at_Pri	-	-	-	-
9	Station Equipment	362	171,209	STATIONS	-	NCP_at_Pri	-	-	-	-
10	Poles, Towers and Fixtures	364	185,255	Func-364	NCP_at_115	NCP_at_Pri	DEMAND	NCP_at_Sec	-	-
11	Overhead Conductors and Devices	365	265,515	Func-365	NCP_at_115	NCP_at_Pri	DEMAND	NCP_at_Sec	-	-
12	Underground Conduit	366	62,534	Func-366	NCP_at_115	NCP_at_Pri	DEMAND	NCP_at_Sec	-	-
13	Underground Conductors & Devices	367	135,960	Func-367	NCP_at_115	NCP_at_Pri	DEMAND	NCP_at_Sec	-	-
14	Line Transformers	368	160,299	PRIM	-	Xfmr (DIV 18-1)	-	-	-	-
15	Services	369	72,382	SEC	-	-	CUST	-	Services_Cost	-
16	Meters	370	49,671	BILL	-	-	-	-	-	Meter_Cost
17	Installations on Cust. Prem./ARO	371/374	165	BILL	-	-	-	-	-	Meter_Cost
18	Street Lighting & Signal Systems	373	52,924	SEC	-	-	CUST	-	Light-Fixtures	-
19	Subtotal - DISTRIBUTION PLANT	360-373	1,172,696							
20										
21	**C. GENERAL PLANT**									
22	Land and Land Rights	389	952	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
23	Structures and Improvements	390	23,532	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
24	Office Furniture and Equipment	391	859	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
25	Passenger Cars - Transp Equipment	392	646	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
26	Stores Equipment	393	454	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
27	Tools, Shop & Garage Equipment	394	2,678	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
28	Laboratory Equipment	395	1,905	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
29	Communications Equipment	396	25,774	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
30	Miscellaneous Equipment	397/399.1	123	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
31	Subtotal - GENERAL PLANT	389-399	56,923							
32										
33	**TOTAL UTILITY PLANT**									
34										
35	**II. DEPRECIATION RESERVE**									
36	Production	108.3	(3,120)	SUBT	SUBT-PrPT-D	-	-	-	-	-
37	Distribution	108.5	(488,824)	DISTPT	SUBT-DxPT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-DxPT-C
38	General	108.6	(24,583)	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
39	TOTAL DEPREC. RESERVE	108	(516,527)							

Class Cost of Service Study ($000s) Allocators Assigned

	Account Description	Account No.	Dollars	Functional Allocator	SubTransmission Demand Allocator	Primary Dist Demand Allocator	Secondary Dist Classification Allocator	Secondary Dist Demand Allocator	Secondary Dist Customer Allocator	Billing Customer Allocator
40										
41	**III. OTHER RATE BASE ITEMS**									
42	Property Held for Future Use	131	204	PLANT	SUBT-PT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-PT-C
43	Contributions in Aid of Construction	255	(103)	PLANT	SUBT-PT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-DxPT-C
44	Materials and Supplies	255	6,378	PLANT	SUBT-PT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-DxPT-C
45	Loss on Reacquired Debt	255	4,592	PLANT	SUBT-PT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-DxPT-C
45	Cash Working Capital		17,789	OPEXP	SUBT-EXP-D	PRI-EXP-D	SEC_EXP	SEC-EXP-D	SEC-EXP-C	BILL-EXP-C
46	Accumulated Deferred FIT	154	(113,088)	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
47	Customer Deposits	182	(3,283)	BILL	-	-	-	-	-	CustDep
48	Injuries and Damages Reserve		(4,762)	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
49	Total - OTHER RATE BASE ITEMS	131-283	(92,273)							
50										
51	**TOTAL RATE BASE**									
52										
53	**I. OPERATING AND MAINTENANCE EXPENSES**									
54	**A. DISTRIBUTION EXPENSE**									
55	Purchased Power- Borderline	555	38	SUBT	MWh-Gen	-	-	-	-	-
56	Operation Supervision & Engineering	580	1,481	Dist-LABOR	SUBT-DxLAB-D	PRI-DxLAB-D	SEC-DxLABOR	SEC-DxLAB-D	SEC-DxLAB-C	BILL-DxLAB-C
57	Load Dispatching	581	2,372	SUBT	MWh-Gen	-	-	-	-	-
58	Station Expenses	582	3,174	STATIONS	-	NCP_at_PRI	-	-	-	-
59	Overhead Line Expenses	583	5,315	OH_Total	NCP_at_115	NCP_at_PRI	DEMAND	NCP_at_Sec	-	-
60	Underground Line Expenses	584	1,849	Func-367	NCP_at_115	NCP_at_PRI	DEMAND	NCP_at_Sec	-	-
61	Street Light and Signal Systems	585	530	SEC	-	-	CUST	-	Light-Fixtures	-
62	Meter Expenses	586	2,842	BILL	-	-	-	-	-	Meter_Cost
63	Customer Installation Expenses	587	1,569	Func-364	NCP_at_115	NCP_at_PRI	DEMAND	NCP_at_Sec	-	-
64	Misc. Distribution Expenses	588	12,495	Dist-LABOR	SUBT-DxLAB-D	PRI-DxLAB-D	SEC-DxLABOR	SEC-DxLAB-D	SEC-DxLAB-C	BILL-DxLAB-C
65	Rents	589	109	DISTPT	SUBT-PT-D	PRI-PT-D	SEC_DiPT	SEC-PT-D	SEC-DxPT-C	BILL-DxPT-C
66	Maint Supervision & Engineering	590	42	Dist-LABOR	SUBT-DxLAB-D	PRI-DxLAB-D	SEC-DxLABOR	SEC-DxLAB-D	SEC-DxLAB-C	BILL-DxLAB-C
67	Maint of Structures	591	25	STATIONS	-	NCP_at_PRI	-	-	-	-
68	Maintenance of Station Equipment	592	3,332	STATIONS	-	NCP_at_PRI	-	-	-	-
69	Maintenance of Overhead Lines	593	18,701	OH_Total	NCP_at_115	NCP_at_PRI	DEMAND	NCP_at_Sec	-	-
70	Maintenance of Underground Lines	594	1,095	Func-367	NCP_at_115	NCP_at_PRI	DEMAND	NCP_at_Sec	-	-
71	Maintenance of Line Transformers	595	263	PRIM	-	Xfmr (DIV 18-1)	-	-	-	-
72	Maintenance of Street Lights	596	1,652	SEC	-	-	CUST	-	Light-Fixtures	-
73	Maintenance of Meters	597	318	BILL	-	-	-	-	-	BILL-DxPT-C
74	Total - OPER. AND MAINT. EXP.	500-599	57,202							
75										

Class Cost of Service Study ($000s) Allocators Assigned

	Account Description	Account No.	Dollars	Functional Allocator	SubTransmission Demand Allocator	Primary Dist Demand Allocator	Secondary Dist Classification Allocator	Secondary Dist Demand Allocator	Secondary Dist Customer Allocator	Billing Customer Allocator
76	**B. CUSTOMER ACCOUNTS AND SERVICE**									
77	Supervision	901	1,197	BILL	-	-	-	-	-	Acct903
78	Meter Reading Expenses	902	1,626	BILL	-	-	-	-	-	Meter_Cost
79	Customer Records & Collection Expense	903	11,449	BILL	-	-	-	-	-	Acct903
80	Uncollectible Accounts- Delivery	904	4,301	BILL	-	-	-	-	-	Total_Del_Rev
81	Uncollectible Accounts- Commodity	904Com		-	-	-	-	-	-	-
82	Misc Customer Accounts Expenses	905	1,074	BILL	-	-	-	-	-	Customers
83	Subtotal - Customer Accounts Exp.	901-905	19,647							
84										
85	Supervision	907	88	BILL	-	-	-	-	-	Acct908
86	Customer Assistance Exp Electric	908-909	1,860	BILL	-	-	-	-	-	Acct908
85	Customer Assistance Expenses	910	3,460	BILL	-	-	-	-	-	Acct910
86	Subtotal - Customer Service & Info.	907-913	5,408							
87										
88	Total - CUST. ACCT. & SERV. EXP.	901-919	25,055							
89										
90	**C. ADMINISTRATIVE AND GENERAL**									
91	GENERAL EXPENSES									
92	A&G-Salaries	920	9,223	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
93	A&G-Office Supplies	921	9,498	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
94	A&G-Outside Services Employed	923	1,902	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
95	Property Insurance	924	1,037	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
96	Injuries & Damages Insurance	925	6,804	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
97	Employee Pensions & Benefits	926	22,946	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
98	Regulatory Comm Expenses	928	5,083	RATEBASE	RateBase	RateBase	SEC_RB	RateBase	RateBase	RateBase
99	A&G-Misc Expenses	930200	3,870	PLANT	MWh-Gen	MWh-Gen	SECPT	MWh-Gen	MWh-Gen	MWh-Gen
100	A&G-Research & Development	930210	125	RATEBASE	RateBase	RateBase	SEC_RB	RateBase	RateBase	RateBase
101	A&G-Rents	931	4,590	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
101	A&G Maint-General Plant-Elec	935	252	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
102	TOTAL A&G EXPENSES	920-932								
103										
104	TOTAL OPERATING EXPENSES									
105										
106	**II. DEPRECIATION EXPENSE**									
107	Depreciation Expense	403	41,466	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
108	TOTAL DEPREC. EXPENSE	403								
109										

Class Cost of Service Study ($000s) Allocators Assigned

	Account Description	Account No.	Dollars	Functional Allocator	SubTransmission Demand Allocator	Primary Dist Demand Allocator	Secondary Dist Classification Allocator	Secondary Dist Demand Allocator	Secondary Dist Customer Allocator	Billing Customer Allocator
110	**III. TAXES and OTHER**									
111	**A. GENERAL TAXES**									
112	Municipal taxes	408	20,085	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
113	Payroll taxes	408	3,700	LABOR	SUBT-LAB-D	PRI-LAB-D	SECLABOR	SEC-LAB-D	SEC-LAB-C	BILL-LAB-C
114	Other taxes	408	275	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
115	Subtotal - General Taxes									
116										
117	**B. FEDERAL / STATE INCOME TAXES**									
118	Amort. ITC		(488)	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
119	Federal Income Tax Expense		(3,198)	RATEBASE	RATEBASE	RATEBASE	SEC_RB	RATEBASE	RATEBASE	RATEBASE
120	Subtotal - Federal / State Income Taxes	409-411								
121										
122	TOTAL TAXES	408-411	20,374							
123										
124	C. OTHER									
125	Merger / Synergy Benefits		(850)	RATEBASE	RATEBASE	RATEBASE	SECPT	RATEBASE	RATEBASE	RATEBASE
126	Amortization of Loss on Reacq Debt		686	PLANT	SUBT-PT-D	PRI-PT-D	SECPT	SEC-PT-D	SEC-PT-C	BILL-PT-C
127	Interest on Customer deposits		75	BILL	-	-	-	-	-	CustDep
128	Subtotal- Other									
129										
130	TOTAL EXPENSES		209,338							
131										
132	**IV. OPERATING REVENUES at Current Rate**									
133	Distribution charge revenue	440	215,420	RevReq_PF	Total_Del_Rev	Total_Del_Rev	SECPT	Total_Del_Rev	Total_Del_Rev	Total_Del_Rev
134	Forfeited discounts	450-451	2,230	BILL	-	-	-	-	-	Write-Offs
135	Rent from Utility property	451Misc	2,644	Func-364	NCP_at_115	NCP_at_Pri	DEMAND	NCP_at_Sec	-	-
136	Other revenue	454	2,948	RevReq_PF	Total_Del_Rev	Total_Del_Rev	SECPT	Total_Del_Rev	Total_Del_Rev	Total_Del_Rev
137	Total Operating Revenues									
138										
139										
140										
141	**V. NET INCOME at Current Rate**									
163										
164										

Class Cost of Service Study ($000s)
UNITIZED REVENUE REQUIREMENTS, RATE BASE AND COSTS

	Unit Cost Component	Units	System Average		Residential A16 / A60	Small C&I C6	General C&I G2 / E40	200 kW Demand B32 / G32	3000 kW Demand B62 / G62	Lighting S10 / S14	Propulsion X1
	UNITIZED REVENUE REQUIREMENTS										
1	SubTransmission Demand (kW-Month) (includes Hydro Production)	NCP_at_115	0.78	#	0.73	0.72	0.80	0.87	0.84	0.81	0.54
2	Primary Dist Demand (kW-Month)	NCP_at_Pri	6.88	#	7.07	7.06	7.06	6.44	6.43	6.64	5.90
3	Secondary Dist Demand (kW-Month)	NCP_at_Sec	2.33	#	2.31	2.31	2.31	-	-	2.44	-
4	Secondary Dist Customer (Cust-Mth)	Cust-Months	3.94	#	1.57	1.90	3.36	14.83	663.24	-	266.47
5	Billing Customer (Cust-Mth)	Cust-Months	9.96	#	8.25	13.52	45.18	216.55	4,256.93	-	648.30
6	Total Demand-related (kW-Month)	NCP_at_115	8.95		9.67	9.64	9.70	7.12	7.07	9.46	6.25
7	Total Customer-related (Cust-Mth)	Cust-Months	13.90		9.81	15.42	48.54	231.38	4,920.18	-	914.77
	UNITIZED RATE BASE										
8	SubTransmission Demand (kW-Month) (includes Hydro Production)	NCP_at_115	1.01		1.00	0.99	1.02	1.05	1.03	1.02	0.93
9	Primary Dist Demand (kW-Month)	NCP_at_Pri	18.36		19.13	19.13	19.11	16.59	16.59	14.86	14.76
10	Secondary Dist Demand (kW-Month)	NCP_at_Sec	5.29		5.29	5.29	5.29	-	-	5.31	-
11	Secondary Dist Customer (Cust-Mth)	Cust-Months	11.58		6.33	7.54	7.98	5.30	88.11	-	35.21
12	Billing Customer (Cust-Mth)	Cust-Months	6.35		5.56	8.04	24.13	105.70	583.17	-	79.55
13	Total Demand-related (kW-Month)	NCP_at_115	22.19		24.28	24.27	24.23	17.04	17.03	20.20	15.15
14	Total Customer-related (Cust-Mth)	Cust-Months	17.94		11.89	15.58	32.11	111.00	671.27	-	114.76
	UNITIZED COSTS										
15	SubTransmission Demand (kW-Month) (includes Hydro Production)	NCP_at_115	0.66		0.61	0.60	0.68	0.75	0.72	0.69	0.43
16	Primary Dist Demand (kW-Month)	NCP_at_Pri	4.67		4.77	4.76	4.76	4.44	4.43	4.86	4.12
17	Secondary Dist Demand (kW-Month)	NCP_at_Sec	1.70		1.68	1.68	1.68	-	-	1.81	-
18	Secondary Dist Customer (Cust-Mth)	Cust-Months	2.55		0.81	1.00	2.40	14.20	652.65	-	262.23
19	Billing Customer (Cust-Mth)	Cust-Months	9.20		7.58	12.55	42.28	203.84	4,186.81	-	638.74
20	Total Demand-related (kW-Month)	NCP_at_115	6.28		6.75	6.72	6.79	5.07	5.03	7.03	4.43
21	Total Customer-related (Cust-Mth)	Cust-Months	11.74		8.38	13.55	44.68	218.04	4,839.45	-	900.97

Class Cost of Service Study ($000s)
FUNCTIONAL CLASIFIED REVENUE REQUIREMENTS, RATE BASE AND COSTS

	Unit Cost Component	Total	Residential A16 / A60	Small C&I C6	General C&I G2 / E40	200 kW Demand B32 / G32	3000 kW Demand B62 / G62	Lighting S10 / S14	Propulsion X1
	FUNCTIONAL CLASSIFIED REVENUE REQUIREMENT								
1	SubTransmission Demand (includes Hydro Production)	18,406	7,806	1,452	3,285	4,360	1,239	174	90
2	Primary Dist Demand	156,534	72,406	13,813	27,959	30,917	9,123	1,370	947
3	Secondary Dist Demand	36,254	22,554	4,305	8,638	213	60	479	4
4	Secondary Dist Customer	21,991	7,730	1,019	330	179	48	12,682	3
5	Billing Customer	55,588	40,697	7,238	4,441	2,612	306	286	8
6	Total Demand-related	211,194	102,765	19,570	39,881	35,491	10,421	2,023	1,041
7	Total Customer-related	77,579	48,427	8,257	4,771	2,790	354	12,967	11
8		288,772	151,192	27,828	44,652	38,282	10,776	14,991	1,052
	FUNCTIONAL CLASSIFIED RATE BASE								
9	SubTransmission Demand (includes Hydro Production)	23,898	10,591	2,011	4,189	5,212	1,523	218	155
10	Primary Dist Demand	417,699	195,899	37,431	75,674	79,708	23,555	3,063	2,369
11	Secondary Dist Demand	82,227	51,550	9,851	19,750	27	8	1,041	1
12	Secondary Dist Customer	64,657	31,237	4,037	784	64	6	28,527	0
13	Billing Customer	35,465	27,426	4,303	2,372	1,275	42	46	1
14	Total Demand-related	523,824	258,040	49,292	99,613	84,947	25,085	4,322	2,525
15	Total Customer-related	100,122	58,663	8,341	3,156	1,339	48	28,573	1
16		623,946	316,703	57,633	102,769	86,285	25,134	32,896	2,526
	FUNCTIONAL CLASSIFIED EXPENSES								
17	SubTransmission Demand (includes Hydro Production)	15,532	6,532	1,210	2,781	3,734	1,055	148	71
18	Primary Dist Demand	106,305	48,849	9,312	18,859	21,333	6,290	1,001	662
19	Secondary Dist Demand	26,366	16,355	3,121	6,263	210	59	354	4
20	Secondary Dist Customer	14,216	3,974	534	235	171	47	9,251	3
21	Billing Customer	51,323	37,399	6,720	4,156	2,458	301	280	8
22	Total Demand-related	148,204	71,736	13,643	27,903	25,276	7,405	1,504	737
23	Total Customer-related	65,539	41,373	7,254	4,391	2,630	348	9,531	11
24		213,743	113,109	20,897	32,294	27,906	7,753	11,035	748

Class Cost of Service Study ($000s)
METER-RELATED COMPONENT OF REVENUE REQUIREMENT

	Account Description	Total Dollars	Residential	Small C&I	General C&I	200 kW Demand	3000 kW Demand	Lighting	Propulsion
			A16 / A60	C6	G2 / E40	B32 / G32	B62 / G62	S10 / S14	X1
1	Meter Cost	49,671	33,809	8,204	5,814	1,834	9	0	0
2	Other Rate Base items	(25,219)	(17,170)	(4,164)	(2,947)	(933)	(5)	0	0
3	Meter-Related Rate Base	24,452	16,639	4,040	2,867	901	5	0	0
4	Rate of Return on Rate Base	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%	8.98%
5	Return on Rate Base	2,196	1,494	363	257	81	0	0	0
6	Income Tax Gross-up	745	507	123	87	27	0	0	0
7	Return Component of Revenue Requirement	2,940	2,001	486	345	108	1	0	0
8									
9	Meter Expenses	2,842	1,934	469	333	105	1	0	0
10	Meter Reading Expenses	1,626	1,107	269	190	60	0	0	0
11	O&M Costs	4,468	3,041	738	523	165	1	0	0
12	A&G Expense	3,707	2,476	621	458	151	1	0	0
13	Meter Depreciation Expense	1,759	1,199	290	204	65	0	0	0
14	Cost Component of Revenue Requirement	9,933	6,717	1,649	1,185	381	2	0	0
15									
16	Meter-Related Revenue Requirement	12,874	8,718	2,135	1,530	489	3	0	0
17									
18	Number of Meters	499,717	441,304	48,516	8,776	1,106	15	0	0
19									
20	**Monthly Revenue Requirement per Meter**	**$2.15**	**$1.65**	**$3.67**	**$14.53**	**$36.84**	**$14.04**	**#DIV/0!**	**#DIV/0!**
21									
22	Distribution Plant in Service- Cost	1,172,696	588,495	110,325	197,099	163,220	47,678	61,063	4,815
23	Meter % of Distribution Plant	4.2%	5.7%	7.4%	3.0%	1.1%	0.0%	0.0%	0.0%
24									
25	Materials and Supplies	6,378	3,210	605	1,067	886	258	327	26
26	Accumulated Depreciation	(488,824)	(245,144)	(45,956)	(82,097)	(68,213)	(19,926)	(25,469)	(2,019)
27	ADIT	(113,088)	(56,937)	(10,643)	(18,871)	(15,684)	(4,568)	(5,927)	(460)
28		(595,534)	(298,870)	(55,995)	(99,900)	(83,011)	(24,236)	(31,068)	(2,453)
29									
30	Distribution O&M	57,202	27,128	5,347	9,831	8,558	2,455	3,627	256
31	Customer Accounts	19,647	15,154	1,961	1,254	953	102	219	4
32		76,849	42,282	7,308	11,085	9,511	2,557	3,846	260
33	Meter % of Operating Costs	5.81%	7.19%	10.10%	4.72%	1.73%	0.03%	0.00%	0.00%
34									
35	A&G Costs	65,330	34,427	6,148	9,705	8,704	2,412	3,710	223
36									
37	Distribution Depreciation Expense	41,466	20,877	3,902	6,919	5,751	1,675	2,173	169
38									
39	Effective Tax Rate		25.32%	25.32%	25.32%	25.32%	25.32%	25.32%	25.32%

Class Cost of Service Study ($000s)
LINE-TRANSFORMER COMPONENT OF REVENUE REQUIREMENT

	Account Description	Amount
1	Line Transformers Cost	160,299
2	Other Rate Base items	(81,405)
3	Line Transformers-Related Rate Base	78,894
4	Rate of Return on Rate Base	8.98%
5	Return on Rate Base	7,085
6	Income Tax Gross-up	2,402
7	Return Component of Revenue Requirement	9,487
8		
9	Maintenance of Line Transformers	263
10	A&G Expense	224
11	Line Transformers Depreciation Expense	5,668
12	Cost Component of Revenue Requirement	6,155
13		
14	Transformer-Related Revenue Requirement	15,642
15		
16	Demand Units	1,294,694
17		
18	Monthly Revenue Requirement per kW	$1.01
19	Annual Demand Units- B32/G32/B62/G62	3,733,444
20	Annual Billing Demand Units- B32/G32/B62/G62	7,203,195
21	**Monthly Transformer Billing Credit per kW**	**$0.52**
22	Distribution Plant in Service- Cost	1,172,696
23	Line Transformer % of Distribution Plant	13.7%
24		
25	Materials and Supplies	6,378
26	Accumulated Depreciation	(488,824)
27	ADIT	(113,088)
28		(595,534)
29		
30	Distribution O&M	57,202
31	Customer Accounts	19,647
32		76,849
33	Line Transformer % of Operating Costs	0.34%
34		
35	A&G Costs	65,330
36		
37	Distribution Depreciation Expense	41,466
38		
39	Effective Tax Rate	25.32%

Division Data Request 18-3

Request:

Regarding the ACOSS in Schedule NG-HSG-1, please explain why no line transformer plant in Account 368 and no maintenance of line transformer expenses in Account 595 are allocated to customers in the Lighting and Propulsion rate classes.

Response:

The effect of Lighting classes on the sizing of line transformers is very small. Propulsion is offered at high voltage and does not require line transformers.

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

Division Data Request 18-4

Request:

Please provide for each rate class in the Company's ACOSS the sum of individual diversified customer maximum demands at secondary and primary voltage levels.

Response:

The Company does not monitor or track individual customer demands except for demand-metered customers. Schedule NG-HSG-2, page 31 shows class non-coincident peak demands at secondary and primary voltage levels.

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