
PUC 9-2

Request:

Is the cost of the A-60 customer discount currently allocated to all customers? If not, to who are they allocated? Please identify the appropriate schedule(s).

Response:

The electric low income discount provided to Rate A-60 customers is recovered from all customers. Narragansett Electric's base distribution rates for all customers include recovery of the rate year electric low income discount of $6,446,453 determined in its last rate case in Docket No. 4323. The calculation of this low income discount is presented on Page 1 of Attachment PUC 9-2, which is the Page 2 of Compliance Attachment D (Schedule JAL-4), Proposed Distribution Rate Design, from the Company's January 24, 2013 Compliance Filing in Docket No. 4323. The allocation of this low income discount is presented on Page 2 of Attachment PUC 9-2, which is Compliance Attachment 3B (Schedule JAL-1), the Compliance Revenue Allocation. Lines 29 and 30 present the reallocation of the low income subsidy of $6.446 million to Narragansett Electric's residential and non-residential rate classes.

Prepared by or under the supervision of: Scott McCabe

The Narragansett Electric Company
Rate Design for Residential Rates A-16 / A-60

Line		Billing Units	Rates Before Low Income Discount	Revenue Before Low Income Subsidy	Rate Adjustment for Low Income Subsidy	Rates Including Low Income Subsidy	Compliance Rates Including Reallocation of Capped Classes Rate Rev	Revenue
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Revenue Allocation			**$133,620,023**				**$133,808,673**
2								
3	Customer Charge:							
4	Monthly Bills- A-16	4,669,275	$5.00	$23,346,374		$5.00	$5.00	$23,346,374
5	Monthly Bills- A-60	502,672	$5.00	2,513,358		$0.00	$0.00	0
6								
7	**Customer Charge Revenue**	5,171,946		**25,859,732**				**23,346,374**
8								
9	Energy-based Charge:							
10	kWh Sales- A-16	2,830,141,506	$0.03451	97,668,183	$0.00103	$0.03554	$0.03664	103,696,385
11	kWh Sales- A-60	291,989,246	$0.03451	10,076,549		$0.02207	$0.02317	6,765,391
12		3,122,130,751		107,744,732				110,461,776
13								
14	**Distribution Charge Revenue**			**107,744,732**				**110,461,776**
15								
16	Rate A-16 Rev			121,014,558				127,042,759
17	Rate A-60 Rev			12,589,907				6,765,391
18								
19	**Total Revenue**			**$133,604,464**				**$133,808,150**
20								
21	Difference			($15,559)				($523)
22								
23								
24	Subsidy:							
25	Rate A-16 Customer Chg	$5.00						
26	Rate A-60 Customer Chg	$0.00						
27	Difference	($5.00)						
28								
29	Billing Units	502,672						
30	Subsidy - Customer Chg	($2,513,358)						
31								
32	Rate A-16 kWh Chg	$0.03554						
33	Rate A-60 kWh Chg	$0.02207						
34	Difference	($0.01347)						
35								
36	Billing Units	291,989,246						
37	Subsidy - kWh Chg	($3,933,095)						
38								
39	Total Subsidy	($6,446,453)						
40								
41								

Line		
42	Notes:	
43	Line (4), Column (a): Page 13, Column (a), Line (10)	Line (4), Column (f): Column (e)
44	Line (5), Column (a): Page 13, Column (a), Line (11)	Line (5), Column (f): Column (e)
45	Line (7), Column (a): Line (4) + Line (5)	Line (10), Column (f): Column (e) + $0.00110 per kWh, reallocation of capped classes shortfall
46	Line (10), Column (a): Page 13, Column (h), Line (10)	Line (11), Column (f): Column (e) + $0.00110 per kWh, reallocation of capped classes shortfall
47	Line (11), Column (a): Page 13, Column (h), Line (11)	Line (1), Column (g): Compliance Att 3B (Schedule JAL-1-C Page 1, Line (45) Column (b) x 1,000)
48	Line (12), Column (a): Line (10) + Line (11)	Line (4), Column (g): Column (a) x Column (f)
49	Line (4), Column (b): Compliance	Line (5), Column (g): Column (a) x Column (f)
50	Line (5), Column (b): Line (4)	Line (7), Column (g): Line (4) + Line (5)
51	Line (10), Column (b): Compliance	Line (10), Column (g): Column (a) x Column (f)
52	Line (11), Column (b): Line (10)	Line (11), Column (g): Column (a) x Column (f)
53	Line (1), Column (c): Compliance Att 3B (Schedule JAL-1-S Page 1, Line (27)	Line (12), Column (g): Line (10) + Line (11)
54	Line (4), Column (c): Column (a) x Column (b)	Line (14), Column (g): Line (12)
55	Line (5), Column (c): Column (a) x Column (b)	Line (16), Column (g): Line (4) + Line (10)
56	Line (7), Column (c): Line (4) + Line (5)	Line (17), Column (g): Line (5) + Line (11)
57	Line (10), Column (c): Column (a) x Column (b)	Line (19), Column (g): Line (16) + Line (17)
58	Line (11), Column (c): Column (a) x Column (b)	Line (21), Column (g): Line (19) - Line (1)
59	Line (12), Column (c): Line (10) + Line (11)	Line (25), Column (a): Line (4), Column (b)
60	Line (14), Column (c): Line (12)	Line (26), Column (a): Line (5), Column (f)
61	Line (16), Column (c): Line (4) + Line (10)	Line (27), Column (a): Line (26)- Line (25)
62	Line (17), Column (c): Line (5) + Line (11)	Line (29), Column (a): Line (5), Column (a)
63	Line (19), Column (c): Line (16) + Line (17)	Line (30), Column (a): Line (27) x Line (29)
64	Line (21), Column (c): Line (19) - Line (1)	Line (32), Column (a): Line (10), Column (e)
65	Line (10), Column (d): Subsidy ÷ kWh less A-60 kWh	Line (33), Column (a): Line (11), Column (e)
66	Line (4), Column (e): Column (b)	Line (34), Column (a): Line (33) - Line (32)
67	Line (5), Column (e): Compliance	Line (36), Column (a): Line (11), Column (a)
68	Line (10), Column (e): Column (b) + Column (d)	Line (37), Column (a): Line (34) x Line (36)
69	Line (11), Column (e): Compliance	Line (39), Column (a): Line (30) + Line (37)

X:\2012 neco\General Rate Case (4323)\Compliance Filing (Debt issuance)\Electric ACOS & Rate Design\Attachment 3\Sch JAL 1_3_4-S (Compliance).xls

The Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4323
Compliance Attachment 3B
(Schedule JAL-1)
Page 1 of 1

The Narragansett Electric Company
RESULTS OF ALLOCATED COST OF SERVICE STUDY AND REVENUE ALLOCATION

Line		Total	Residential Rate A-16/ A-60	Small C&I Rate C-06	General C&I Rate G-02	200 kW Demand Rate G-32	3000 kW Demand Rate G-62	Lighting Rates S-10/S-14	Propulsion Rate X-01
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	SECTION 1. SUMMARY OF RESULTS OF ALLOCATED COST OF SERVICE STUDY								
1	Rate Base	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
2									
3	Compliance Rate of Return	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%	7.17%
4									
5	Return on Rate Base	$40,277	$21,258	$3,911	$5,912	$5,568	$1,401	$2,100	$126
6									
7	Operating Expenses (including taxes)	$219,670	$115,917	$21,697	$31,234	$29,954	$7,436	$12,842	$590
8									
9	Total Distribution Revenue Requirement	$259,947	$137,175	$25,607	$37,146	$35,522	$8,837	$14,942	$717
10									
11	less: Other revenue	$8,163	$3,555	$1,318	$1,593	$935	$477	$269	$15
12									
13	Distribution Rate Revenue Requirement	$251,784	$133,620	$24,289	$35,554	$34,587	$8,360	$14,673	$702
14									
15	Present Total Distribution Revenue	$239,023	$123,070	$25,514	$38,676	$35,317	$5,527	$10,426	$494
16									
17	Present Other Revenue	$8,147	$3,547	$1,317	$1,591	$933	$477	$268	$15
18									
19	Present Distribution Rate Revenue	$230,876	$119,523	$24,198	$37,085	$34,384	$5,050	$10,158	$479
20									
21	Increase/(Decrease) - Total Dist Revenue	$20,924	$14,106	$93	-$1,529	$205	$3,310	$4,516	$223
22									
23	**Percentage Increase/(Decrease)**	8.8%	11.5%	0.4%	-4.0%	0.6%	59.9%	43.3%	45.1%
24									
25	**SECTION 2. COMPLIANCE REVENUE ALLOCATION**								
26									
27	Revenue Requirement @ Equal ROR	$251,784	$133,620	$24,289	$35,554	$34,587	$8,360	$14,673	$702
28									
29	A-60 Rate Design Subsidy	-$6,446	-$6,446						
30	A-60 subsidy Re-allocated on Dist Rev Req Basis	$6,446	$3,421	$622	$910	$886	$214	$376	$18
31	Reallocation of Total A-60 Subsidy	$0	-$3,025	$622	$910	$886	$214	$376	$18
32									
33	Revenue Requirement w/ Low Income Subsidy	$251,784	$130,595	$24,911	$36,464	$35,472	$8,574	$15,048	$720
34	Increase/(Decrease) incl. Low Income Subsidy	$20,908	$11,072	$713	-$621	$1,089	$3,524	$4,891	$241
35									
36	Rev Req (Unconstrained Classes)	$227,442	$130,595	$24,911	$36,464	$35,472			
37	% of Unconstrained Rev Req		57.42%	10.95%	16.03%	15.60%			
38									
39	Increase Constraint- 2 x system average						13.1%	17.5%	17.5%
40	Apply Constraint						$724	$1,825	$86
41									
42	Shortfall from Constrained Classes	-$6,020					-$2,800	-$3,066	-$154
43	Re-allocation of Shortfall on Rev Req	$6,020	$3,457	$659	$965	$939			
44	Energy Efficiency Uncollectibles	-$611	-$243	-$47	-$101	-$180	-$34	-$5	-$2
45	**Revenue Requirement**	$251,173	$133,809	$25,524	$37,328	$36,232	$5,740	$11,977	$564
46									
47	Increase/(Decrease) - Dist Rate Revenue	$20,297	$14,286	$1,326	$243	$1,848	$690	$1,819	$85
48									
49	Increase in Other Revenue	$16	$8	$2	$2	$2	$1	$1	$0
50	Recovery of Egy Eff Uncollectibles thru EE rates	$611	$243	$47	$101	$180	$34	$5	$2
51									
52	Increase/(Decrease) - Total Dist Revenue	$20,924	$14,537	$1,374	$346	$2,030	$725	$1,825	$86
53									
54	**Percentage Increase/(Decrease)**	8.8%	11.8%	5.4%	0.9%	5.7%	13.1%	17.5%	17.5%
55									
56	Return on Rate Base at Compliance Rates	7.17%	7.32%	9.52%	9.44%	9.52%	(6.06%)	(2.02%)	(0.55%)
57									
58									

59 Notes:
60 Line (1): Compliance Attachment 3A, Page 1, Line (10)
61 Line (3): Compliance Attachment 3A, Page 1, Line (32)
62 Line (5): Line (1) x Line (3)
63 Line (7): Compliance Attachment 3A, Page 1, Line (27) + Line (29)
64 Line (9): Line (5) + Line (7)
65 Line (11): Compliance Attachment 3A, Page 1, Line (17) + Line (18) + Line (19)
66 Line (13): Line (9) - Line (11)
67 Line (15): Compliance Attachment 3A, Page 1, Line (1)
68 Line (17): Compliance Attachment 3A, Page 1, Line (2)
69 Line (19): Line (15) - Line (17)
70 Line (21): Line (9) - Line (15)
71 Line (23): Line (15) ÷ Line (21)
72 Line (27): Line (13)
73 Line (29): (Compliance Attachment 3D: Page 2, Line (39))
74 Line (30): - Line (29) allocated by Distribution Revenue Requirement on Line (13)
75 Line (31): Line (29) + Line (30)

Line (33): Line (27) + Line (31)
Line (34): Line (33) - Line (19)
Line (36): Line (33) for unconstrained classes
Line (37): Line (36) ÷ Line (36) Total
Line (39): Constraint: Column (f) Line (23) Total x 1.5, Columns (g) and (h) Line (23) Total x 2
Line(40): Line (15) x Line (39) for constrained classes
Line (42): Line (40) - Line (34)
Line (43): Line (37) x Line (42) Total for unconstrained classes
Line (44): Energy Efficiency Uncollectibles per Compliance Attachment 1, page 3
Line (45): Line (33) + Line (42) + Line (43) + Line (44)
Line (47): Line (45) - Line (19)
Line (49): Line (11) - Line (17)
Line (50): Line (44)
Line (52): Line (47) + Line (49) + Line (50)
Line (54): Line (52) ÷ Line (15)
Line (56): [Line (45) + Line (11) - Operating Expense - Inc Taxes] ÷ Line (1)

PUC 9-3

Request:

Are the costs of the low income discounted rate on gas currently allocated to all customers? If not, to whom are they allocated? Please identify the appropriate schedule(s).

Response:

Narragansett Gas implemented its current low income discounted rates effective December 1, 2008 as part of its 2008 rate case in Docket No. 3943. Attachment PUC 9-3-1 includes a copy of Attachment NG-Compliance RD-1, Page 1, from Docket No. 3943-National Grid Request for Change of Gas Distribution Rates Compliance filing dated November 26, 2008. In Attachment PUC 9-3-1, Narragansett Gas allocated the low income subsidy to all other non-discounted residential and Commercial and Industrial (C&I) rate classes based each class's annual usage as a percent of total company annual usage.

In Narragansett Gas' subsequent rate case, Docket No. 4323, Narragansett Gas did not present the rate design schedules in the same format as the prior filing, as reflected in Attachment PUC 9-3-2. In Docket No. 4323, Narragansett Gas' approach to revenue allocation was to move towards equalized rates of return for all rate classes; however, Narragansett Gas recognized that this approach would result in very large bill increases for the residential rate classes and bill decreases for many of its C&I rate classes. Therefore, Narragansett Gas imposed limits on all revenue increases, which ranged from a minimum increase of 4 percent to a maximum increase of 11.72 percent (1.67 times the overall system average increase of 8.07 percent). See Attachment PUC 9-3-2 Page 2 Column (Z) for the preliminary percent distribution revenue increase applied to the current revenues and Page 4 Column (Z) for the final percent distribution revenue increase resulting from the implementation of new base distribution rates. This range of revenue increases was applied to all firm rate classes including Rate 11 (Residential Non Heating Low Income) and Rate 13 (Residential Heating Low Income). Therefore, the schedules provided for Docket No. 4323 do not specifically identify the low income discount and how it was allocated to all other rate classes. However, because the increases were applied to the current rate class revenues, which included the recovery of the low income discount as shown in Attachment PUC 9-3-1, the rate class revenue requirements in Docket No. 4323 inherently include recovery of the low income discount from all other rate classes. Consequently, since Narragansett Gas increased the distribution revenue for each rate class based upon increases ranging from 4 percent to 11.72 percent, it is impossible to separately identify how much of the overall revenue increase is due solely to the recovery of the low income discount.

Prepared by or under the supervision of: Ann Leary

NationalGrid RI
Docket No.3943
Proposed Revenue Spread - Compliance

Attachment NG-Compliance RD-1
Page 1 of 1

Line No.	Rate Schedule	Current Distribution Revenue	Proposed Increase	Proposed Distr. Rev. before LI Discount	Percentage Increase	Low Income Full Rate Reallocation	Low Income Discount Revenue $ 792,453	Total Proposed Distribution Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Non-Heat	$ 5,133,293	$ 781,903	$ 5,915,196	15.23%	$ (485,600)	$ 12,037	$ 5,441,633
2	Residential Non-Heat Discount	-	-	-	0.00%	485,600	(48,565)	437,035
3	Residential Heat	82,164,785	8,939,534	91,104,319	10.88%	(7,439,952)	379,512	84,043,878
4	Residential Heat Discount	-	-	-	0.00%	7,439,952	(743,888)	6,696,064
5	Small C/I	10,491,164	1,426,798	11,917,962	13.60%		54,238	11,972,200
6	Medium C/I	14,650,241	1,155,611	15,805,852	7.89%		120,912	15,926,764
7	Large Low	6,730,933	530,936	7,261,869	7.89%		60,898	7,322,767
8	Large High	1,812,681	172,370	1,985,051	9.51%		23,720	2,008,771
9	X-Large Low	1,108,782	156,826	1,265,608	14.14%		27,671	1,293,279
10	X-Large High	3,473,673	491,316	3,964,989	14.14%		113,465	4,078,454
11	NGV	22,738	2,474	25,212	10.88%			25,212
12	Gas Lights	18,423	2,004	20,427	10.88%			20,427
13	Total	$ 125,606,713	$ 13,659,773	$ 139,266,486	10.88%	$ -	$ 0	$ 139,266,486
14	Percent Increase		10.88%					

NG RI PROPOSED GAS RATE DESIGN

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Weather Normalized Sales											
Rate	CURRENT RATES	Annual Customers	Existing Customer Charge	Sales (therms)	Transp (therms)		Total Therms	Annual Proposed Blocking Therms	First Block % usage	First Block Therms	Tail Block Therms	MADQ Demand Therms	Dist Chrg Head Per Therms	Dist Chrg Tail Per Therms	Demand Per Therms
80	Gas Lights	2,434	$7.93												
10	Residential, Non-Heat	284,065	$10.00	4,947,155	0		4,947,155	NA	100.00%	4,947,155	0		$0.4029		
11	Residential, Low Income Non-Heat	3,667	$9.00	165,924	0		165,924	NA	100.00%	165,924	0		$0.3626		
	Total Non Heat	287,732		5,113,079	0		5,113,079			5,113,079	0				
12	Residential, Heat Peak	1,100,431	$12.00	124,505,636	0		124,505,636	125	24.45%	91,785,725	32,719,911		$0.3881	$0.2500	
12	Residential, Heat Off-Peak	1,081,105	$12.00	28,986,365	0		28,986,365	30	24.45%	23,453,171	5,533,193		$0.3881	$0.2500	
13	Residential, Low Income Heat Peak	129,392	$10.80	14,202,286	0		14,202,286	125	24.27%	11,216,073	2,986,214		$0.3493	$0.2250	
13	Residential, Low Inc Heat Off-Peak	127,120	$10.80	4,142,494	0		4,142,494	30	24.27%	3,158,282	984,212		$0.3493	$0.2250	
	Total Heating	2,438,049		171,836,781	0		171,836,781			129,613,251	42,223,530				
21	Comm & Indust Small Peak	111,565	$18.60	20,503,114	0		20,503,114	135	13.83%	8,898,615	11,604,499		$0.4845	$0.2000	
21	Comm & Indust Small Off-Peak	108,374	$18.60	4,273,848	0		4,273,848	20	13.83%	1,415,022	2,858,826		$0.4845	$0.2000	
	Total Comm & Ind Small	219,939		24,776,962	0		24,776,962			10,313,637	14,463,325				
22	Comm & Indust Medium Sales	34,336	$60.00	31,970,336	0		31,970,336	NA	100.00%	31,970,336	0	2,218,498	$0.1603		$1.20
22	Comm & Indust Medium FT-1	5,404	$60.00	0	8,171,900		8,171,900	NA	100.00%	8,171,900	0	492,199	$0.1603		$1.20
22	Comm & Indust Medium FT-2	15,442	$60.00	0	16,239,343		16,239,343	NA	100.00%	16,239,343	0	1,162,604	$0.1603		$1.20
22	Total Comm & Indust Medium	55,182		31,970,336	24,411,242		56,381,579			56,381,579	0	3,873,301			
33	Comm & Indust Large LLF Sales	1,513	$120.00	7,242,539	0		7,242,539	NA	100.00%	7,242,539	0	518,728	$0.1638		$1.20
33	Comm & Indust Large LLF FT-1	1,791	$120.00	0	9,529,039		9,529,039	NA	100.00%	9,529,039	0	775,412	$0.1638		$1.20
33	Comm & Indust Large LLF FT-2	1,612	$120.00	0	9,127,229		9,127,229	NA	100.00%	9,127,229	0	611,461	$0.1638		$1.20
33	Total Comm & Ind Large LLF	4,916		7,242,539	18,656,268		25,898,807			25,898,807	0	1,905,602			
23	Comm & Indust Large HLF Sales	550	$120.00	2,746,868	0		2,746,868	NA	100.00%	2,746,868	0	138,000	$0.0894		$1.66
23	Comm & Indust Large HLF FT-1	828	$120.00	0	6,461,986		6,461,986	NA	100.00%	6,461,986	0	253,936	$0.0894		$1.66
23	Comm & Indust Large HLF FT-2	528	$120.00	0	3,120,146		3,120,146	NA	100.00%	3,120,146	0	147,528	$0.0894		$1.66
23	Total Comm & Ind Large HLF	1,906		2,746,868	9,582,132		12,329,000			12,329,000	0	539,464			
34	Comm & Ind Extra Large LLF Sales	24	$300.00	385,991	0		385,991	NA	100.00%	385,991	0	21,976	$0.0348		$1.20
34	Comm & Ind Extra Large LLF FT-1	288	$300.00	0	6,893,020		6,893,020	NA	100.00%	6,893,020	0	663,988	$0.0348		$1.20
34	Comm & Ind Extra Large LLF FT-2	60	$300.00	0	1,036,515		1,036,515	NA	100.00%	1,036,515	0	57,563	$0.0348		$1.20
34	Tot Com & Ind Extra Large LLF	372		385,991	7,929,534		8,315,525			8,315,525	0	743,527			
24	Comm & Ind Extra Large HLF Sales	72	$300.00	1,837,861	0		1,837,861	NA	100.00%	1,837,861	0	83,025	$0.0268		$1.66
24	Comm & Ind Extra Large HLF FT-1	779	$300.00	0	48,118,084		48,118,084	NA	100.00%	48,118,084	0	2,062,207	$0.0268		$1.66
24	Comm & Ind Extra Large HLF FT-2	96	$300.00	0	2,173,045		2,173,045	NA	100.00%	2,173,045	0	92,496	$0.0268		$1.66
24	Tot Com & Ind Extra Large HLF	947		1,837,861	50,291,129		52,128,989			52,128,989	0	2,237,728			
	Total	3,009,043		245,910,417	110,870,305		356,780,722			300,093,867	56,686,855	9,299,622			
		Excl Lghts									356,780,722				

The Narragansett Electric Company
d/b/a National Grid
R.I.P.U.C. Docket No. 4323
Compliance Attachment 8C
(Schedule PMN-7)
Page 2 of 5

NG RI PROPOSED GAS RATE DESIGN

		(A)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)
1					------------- Cost of Service Results	--------------		Proposed					Prelim
2					Equalized	Revenue	Percent	Increases	Shortfall $	Prelim			Base
3		**CURRENT RATES**	Existing	Existing	ROR	Increase	Increase	Capped @	Allocation on	Class	Target Rev		Percent
4	Rate		Revenues	ROR	7.54% Rev Req	to Equalize	Equal ROR	8.07%	Equal ROR REV	Increase	Req for Class		Increase
5													
6	80	Gas Lights	$19,303		$29,160	$9,857	51.06%	$2,263		$2,263	$21,566		11.72%
7	10	Residential, Non-Heat	$5,247,710		$7,927,320	$2,679,610	51.06%	$615,086		$615,086	$5,862,796		11.72%
8	11	Residential, Low Income Non-Heat	$107,046		$161,707	$54,660	51.06%	$12,547		$12,547	$119,593		11.72%
9		Total Non Heat	$5,374,059	-5.29%	$8,118,186	$2,744,127	51.06%	$629,895		$629,895	$6,003,954		11.72%
10													
11	12	Residential, Heat Peak	$62,044,701		$67,838,481	$5,793,780	9.34%	$5,007,856		$5,007,856	$67,052,557		8.07%
12	12	Residential, Heat Off-Peak	$24,631,530		$26,931,641	$2,300,110	9.34%	$1,988,101		$1,988,101	$26,619,632		8.07%
13	13	Residential, Low Income Heat Peak	$6,561,737		$7,174,477	$612,740	9.34%	$529,622		$529,622	$7,091,359		8.07%
14	13	Residential, Low Inc Heat Off-Peak	$2,865,138		$3,132,687	$267,549	9.34%	$231,256		$231,256	$3,096,394		8.07%
15		Total Heating	$96,103,106	5.00%	$105,077,285	$8,974,179	9.34%	$7,756,835		$7,756,835	$103,859,941		8.07%
16													
17	21	Comm & Indust Small Peak	$9,484,822		$10,036,290	$551,468	5.81%	$551,468		$551,468	$10,036,290		5.81%
18	21	Comm & Indust Small Off-Peak	$3,435,155		$3,634,882	$199,727	5.81%	$199,727		$199,727	$3,634,882		5.81%
19		Total Comm & Ind Small	$12,919,977	5.94%	$13,671,172	$751,195	5.81%	$751,195		$751,195	$13,671,172		5.81%
20													
21	22	Comm & Indust Medium Sales	$10,816,843		$10,268,632	($548,211)	-5.07%	$432,674	($44,253)	$388,421	$11,205,264		3.59%
22	22	Comm & Indust Medium FT-1	$2,472,714		$2,347,393	($125,320)	-5.07%	$98,909	($10,116)	$88,792	$2,561,506		3.59%
23	22	Comm & Indust Medium FT-2	$5,417,366		$5,142,807	($274,559)	-5.07%	$216,695	($22,163)	$194,531	$5,611,897		3.59%
24	22	Total Comm & Indust Medium	$18,706,922	8.76%	$17,758,833	($948,090)	-5.07%	$748,277	($76,533)	$671,744	$19,378,667		3.59%
25							Minimum	4.00%					
26	33	Comm & Indust Large LLF Sales	$2,104,184		$2,048,854	($55,330)	-2.63%	$84,167	($8,830)	$75,338	$2,179,522		3.58%
27	33	Comm & Indust Large LLF FT-1	$2,856,028		$2,780,928	($75,100)	-2.63%	$114,241	($11,985)	$102,257	$2,958,284		3.58%
28	33	Comm & Indust Large LLF FT-2	$2,565,676		$2,498,211	($67,465)	-2.63%	$102,627	($10,766)	$91,861	$2,657,536		3.58%
29	33	Total Comm & Ind Large LLF	$7,525,888	8.11%	$7,327,993	($197,895)	-2.63%	$301,036	($31,580)	$269,455	$7,795,343		3.58%
30							Minimum	4.00%					
31	23	Comm & Indust Large HLF Sales	$569,495		$687,513	$118,018	20.72%	$45,966		$45,966	$615,461		8.07%
32	23	Comm & Indust Large HLF FT-1	$1,166,451		$1,408,178	$241,727	20.72%	$94,149		$94,149	$1,260,600		8.07%
33	23	Comm & Indust Large HLF FT-2	$619,962		$748,439	$128,477	20.72%	$50,039		$50,039	$670,001		8.07%
34	23	Total Comm & Ind Large HLF	$2,355,908	3.92%	$2,844,130	$488,222	20.72%	$190,154		$190,154	$2,546,062		8.07%
35													
36	34	Comm & Ind Extra Large LLF Sales	$49,727		$35,516	($14,211)	-28.58%	$1,989	($153)	$1,836	$51,563		3.69%
37	34	Comm & Ind Extra Large LLF FT-1	$1,171,698		$836,855	($334,843)	-28.58%	$46,868	($3,606)	$43,261	$1,214,960		3.69%
38	34	Comm & Ind Extra Large LLF FT-2	$130,460		$93,177	($37,282)	-28.58%	$5,218	($402)	$4,817	$135,276		3.69%
39	34	Tot Com & Ind Extra Large LLF	$1,351,885	16.30%	$965,549	($386,336)	-28.58%	$54,075	($4,161)	$49,914	$1,401,799		3.69%
40							Minimum	4.00%					
41	24	Comm & Ind Extra Large HLF Sales	$215,314		$180,495	($34,819)	-16.17%	$8,613	($778)	$7,835	$223,149		3.64%
42	24	Comm & Ind Extra Large HLF FT-1	$5,120,312		$4,292,285	($828,027)	-16.17%	$204,812	($18,498)	$186,315	$5,306,627		3.64%
43	24	Comm & Ind Extra Large HLF FT-2	$248,429		$208,255	($40,175)	-16.17%	$9,937	($897)	$9,040	$257,469		3.64%
44	24	Tot Com & Ind Extra Large HLF	$5,584,055	11.71%	$4,681,035	($903,021)	-16.17%	$223,362	($20,173)	$203,189	$5,787,244		3.64%
45							Minimum	4.00%					
46		Total	$149,921,801	5.70%	$160,444,182	$10,522,382	7.02%	$10,654,829	-$132,447	$10,522,382	$160,444,182		7.02%
47						115% cap	1.15	-$132,447					
48					Capped Incr. on Base $$		8.07%	$ Rev shortfall due to cap		11.72%	**1.67times sys avg**		
49						50% min	3.51%						
50						Minumum Incr. on Base $$	4.00%	56.99%					

NG RI PROPOSED GAS RATE DESIGN

Row		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
52																
53					Cost Study	1.20										
54		**CURRENT & PROPOSED RATES**		Existing	@ Equalized	Proposed	Existing Dist Charges		Proposed Charges				Final Adjust.			
55			Annual	Customer	ROR	Customer	Head Per	Tail Per	Therm Blocks			Average	Increase	Proposed	Equal %	Existing
56			Customers	Charge	Cust $ (1)	Charges	Therms	Therms	First	Second	MDD	Rate	col(V) x	RORs	Block	
57	80	Gas Lights	2,434	$7.93	$24.28	$9.52							0.001800		Increase	
58	10	Residential, Non-Heat	284,065	$10.00	$24.28	$13.00	$0.4029		$0.4386			$0.4386				-5.29%
59	11	Residential, Low Income Non-Heat	3,667	$9.00	$24.28	$11.70	$0.3626		$0.3947			$0.4622				-5.29%
60		Total Non Heat	287,732						$0.4391			$0.4391		-2.39%		-5.29%
61																
62	12	Residential, Heat Peak	1,100,431	$12.00	$25.47	$13.00	$0.3881	$0.2500	$0.4672	$0.3010		$0.4237				5.00%
63	12	Residential, Heat Off-Peak	1,081,105	$12.00	$25.47	$13.00	$0.3881	$0.2500	$0.4672	$0.3010		$0.4335				5.00%
64		Total Residential Heat	2,181,536	$12.00	$25.47	$13.00	$0.3881	$0.2500	$0.4672	$0.3010		$0.4255		7.19%	1.2038	5.00%
65															20.38%	
66	13	Residential, Low Income Heat Peak	129,392	$10.80	$25.47	$11.70	$0.3493	$0.2250	$0.4205	$0.2709		$0.3927				5.00%
67	13	Residential, Low Inc Heat Off-Peak	127,120	$10.80	$25.47	$11.70	$0.3493	$0.2250	$0.4205	$0.2709		$0.3884				5.00%
68		Total Heating Low Income	256,513	$10.80	$25.47	$11.70	$0.3493	$0.2250	$0.4205	$0.2709		$0.3917		7.19%		5.00%
69																
70	21	Comm & Indust Small Peak	111,565	$18.60	$34.25	$22.00	$0.4845	$0.2000	$0.5431	$0.2242		$0.3698				5.94%
71	21	Comm & Indust Small Off-Peak	108,374	$18.60	$34.25	$22.00	$0.4845	$0.2000	$0.5431	$0.2242		$0.2926				5.94%
72		Total Comm & Ind Small	219,939	$18.60	$34.25	$22.00	$0.4845	$0.2000	$0.5431	$0.2242	$0.3189	$0.3565		7.56%	1.1210	5.94%
73								Demand			Prop Dem				12.10%	
74	22	Comm & Indust Medium Sales	34,336	$60.00	$82.68	$70.00	$0.1603	$1.20	$0.1865		$1.30					8.76%
75	22	Comm & Indust Medium FT-1	5,404	$60.00	$82.68	$70.00	$0.1603	$1.20	$0.1865		$1.30					8.76%
76	22	Comm & Indust Medium FT-2	15,442	$60.00	$82.68	$70.00	$0.1603	$1.20	$0.1865		$1.30					8.76%
77	22	Total Comm & Indust Medium	55,182	$60.00	$82.68	$70.00	$0.1603	$1.20	$0.1865		$1.30	$0.0200	$34,882	9.66%		8.76%
78																
79	33	Comm & Indust Large LLF Sales	1,513	$120.00	$194.27	$175.00	$0.1638	$1.20	$0.1727		$1.30					8.11%
80	33	Comm & Indust Large LLF FT-1	1,791	$120.00	$194.27	$175.00	$0.1638	$1.20	$0.1727		$1.30					8.11%
81	33	Comm & Indust Large LLF FT-2	1,612	$120.00	$194.27	$175.00	$0.1638	$1.20	$0.1727		$1.30					8.11%
82	33	Total Comm & Ind Large LLF	4,916	$120.00	$194.27	$175.00	$0.1638	$1.20	$0.1727		$1.30		$14,032	8.93%		8.11%
83																
84	23	Comm & Indust Large HLF Sales	550	$120.00	$168.74	$175.00	$0.0894	$1.66	$0.1007		$1.80					3.92%
85	23	Comm & Indust Large HLF FT-1	828	$120.00	$168.74	$175.00	$0.0894	$1.66	$0.1007		$1.80					3.92%
86	23	Comm & Indust Large HLF FT-2	528	$120.00	$168.74	$175.00	$0.0894	$1.66	$0.1007		$1.80					3.92%
87	23	Total Comm & Ind Large HLF	1,906	$120.00	$168.74	$175.00	$0.0894	$1.66	$0.1007		$1.80	$0.0200		5.33%		3.92%
88																
89	34	Comm & Ind Extra Large LLF Sales	24	$300.00	$407.87	$425.00	$0.0348	$1.20	$0.0328		$1.30					16.30%
90	34	Comm & Ind Extra Large LLF FT-1	288	$300.00	$407.87	$425.00	$0.0348	$1.20	$0.0328		$1.30					16.30%
91	34	Comm & Ind Extra Large LLF FT-2	60	$300.00	$407.87	$425.00	$0.0348	$1.20	$0.0328		$1.30					16.30%
92	34	Tot Com & Ind Extra Large LLF	372	$300.00	$407.87	$425.00	$0.0348	$1.20	$0.0328		$1.30		-$4,000	17.34%		16.30%
93																
94	24	Comm & Ind Extra Large HLF Sales	72	$300.00	$463.52	$425.00	$0.0268	$1.66	$0.0256		$1.80					11.71%
95	24	Comm & Ind Extra Large HLF FT-1	779	$300.00	$463.52	$425.00	$0.0268	$1.66	$0.0256		$1.80					11.71%
96	24	Comm & Ind Extra Large HLF FT-2	96	$300.00	$463.52	$425.00	$0.0268	$1.66	$0.0256		$1.80					11.71%
97	24	Tot Com & Ind Extra Large HLF	947	$300.00	$463.52	$425.00	$0.0268	$1.66	$0.0256		$1.80		-$24,000	12.54%		11.71%
98											Increase @					
99		Total	3,009,043								system avg.		$20,913	7.54%		5.70%
		(1) Schedule PMN-5, Page 5, Line 20									107.02%					

NG RI PROPOSED GAS RATE DESIGN

51		(A)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)
52													
53													Final
54		**CURRENT & PROPOSED RATES**	Proposed Revenue Recovery					Total		$ Variance	Final		Base
55			Customer		Therms	Therms		Revenues	Class Target	to target with	Class		Percent
56			Charges		First Block	Second Block	MDD	@ Prop Rates	Rev Req	& Discount	Increase		Increase
57	80	Gas Lights	$23,164					$23,164	$21,566	$1,598	$3,861		20.00%
58	10	Residential, Non-Heat	$3,692,847		2,169,822	$0		$5,862,669	$5,862,796	-$127	$614,959		11.72%
59	11	Residential, Low Income Non-Heat	$42,902		65,490	$0		$108,393	$119,593	-$11,200	$1,346		1.26%
60		Total Non Heat	$3,758,913		$2,235,313	$0		$5,994,225	$6,003,954	-$9,729	$620,166		11.58%
61													
62	12	Residential, Heat Peak	$14,305,603		$42,882,291	$9,848,693		$67,036,587	$67,052,557	-$15,969	$4,991,886		8.05%
63	12	Residential, Heat Off-Peak	$14,054,370		$10,957,322	$1,665,491		$26,677,183	$26,619,632	$57,552	$2,045,653		8.31%
64		Total Residential Heat	$28,359,974		$53,839,612	$11,514,185		$93,713,771	$93,672,188	$41,582	$7,037,539		8.12%
65													
66	13	Residential, Low Income Heat Peak	$1,513,892		$4,716,359	$808,965		$7,039,216	$7,091,359	-$52,143	$477,479		7.28%
67	13	Residential, Low Inc Heat Off-Peak	$1,487,305		$1,328,058	$266,623		$3,081,986	$3,096,394	-$14,408	$216,847		7.57%
68		Total Heating Low Income	$3,001,197		$6,044,416	$1,075,588		$10,121,201	$10,187,753	-$66,552	$694,326		7.37%
69													
70	21	Comm & Indust Small Peak	$2,454,430		$4,832,838	$2,601,729		$9,888,996	$10,036,290	-$147,293	$404,175		4.26%
71	21	Comm & Indust Small Off-Peak	$2,384,228		$768,499	$640,949		$3,793,675	$3,634,882	$158,793	$358,520		10.44%
72		Total Comm & Ind Small	$4,838,658		$5,601,336	$3,242,677		$13,682,672	$13,671,172	$11,500	$762,695		5.90%
73													
74	22	Comm & Indust Medium Sales	$2,403,497		$5,962,468		$2,884,048	$11,250,012	$11,205,264	$44,748	$433,169		4.00%
75	22	Comm & Indust Medium FT-1	$378,309		$1,524,059		$639,859	$2,542,228	$2,561,506	-$19,278	$69,514		2.81%
76	22	Comm & Indust Medium FT-2	$1,080,958		$3,028,637		$1,511,385	$5,620,980	$5,611,897	$9,083	$203,614		3.76%
77	22	Total Comm & Indust Medium	$3,862,763		$10,515,164		$5,035,292	$19,413,220	$19,378,667	$34,553	$706,297		3.78%
78													
79	33	Comm & Indust Large LLF Sales	$264,775		$1,250,786		$674,347	$2,189,908	$2,179,522	$10,386	$85,724		4.07%
80	33	Comm & Indust Large LLF FT-1	$313,425		$1,645,665		$1,008,036	$2,967,126	$2,958,284	$8,841	$111,098		3.89%
81	33	Comm & Indust Large LLF FT-2	$282,100		$1,576,272		$794,899	$2,653,272	$2,657,536	-$4,264	$87,596		3.41%
82	33	Total Comm & Ind Large LLF	$860,300		$4,472,724		$2,477,282	$7,810,306	$7,795,343	$14,963	$284,418		3.78%
83													
84	23	Comm & Indust Large HLF Sales	$96,250		$276,610		$248,400	$621,260	$615,461	$5,799	$51,765		9.09%
85	23	Comm & Indust Large HLF FT-1	$144,900		$650,722		$457,085	$1,252,707	$1,260,600	-$7,893	$86,255		7.39%
86	23	Comm & Indust Large HLF FT-2	$92,400		$314,199		$265,551	$672,149	$670,001	$2,148	$52,188		8.42%
87	23	Total Comm & Ind Large HLF	$333,550		$1,241,530		$971,036	$2,546,116	$2,546,062	$54	$190,208		8.07%
88													
89	34	Comm & Ind Extra Large LLF Sales	$10,200		$12,661		$28,569	$51,429	$51,563	-$134	$1,702		3.42%
90	34	Comm & Ind Extra Large LLF FT-1	$122,400		$226,091		$863,184	$1,211,675	$1,214,960	-$3,284	$39,977		3.41%
91	34	Comm & Ind Extra Large LLF FT-2	$25,500		$33,998		$74,832	$134,329	$135,276	-$947	$3,870		2.97%
92	34	Tot Com & Ind Extra Large LLF	$158,100		$272,749		$966,585	$1,397,434	$1,401,799	-$4,365	$45,549		3.37%
93													
94	24	Comm & Ind Extra Large HLF Sales	$30,600		$47,049		$149,445	$227,094	$223,149	$3,946	$11,780		5.47%
95	24	Comm & Ind Extra Large HLF FT-1	$331,075		$1,231,823		$3,711,973	$5,274,871	$5,306,627	-$31,756	$154,559		3.02%
96	24	Comm & Ind Extra Large HLF FT-2	$40,800		$55,630		$166,493	$262,923	$257,469	$5,454	$14,494		5.83%
97	24	Tot Com & Ind Extra Large HLF	$402,475		$1,334,502		$4,027,911	$5,764,888	$5,787,244	-$22,356	$180,833		3.24%
98													
99		Total	$45,575,930		$85,557,347	$15,832,450	$13,478,105	$160,443,832	$160,444,182	-$350	$10,522,032		7.02%

(1) Schedule PMN-5, Page 5, Line 20

NG RI PROPOSED GAS RATE DESIGN

Non-Firm Volumetric Rates

Line No.	Rate Class (A)	Revenues: Demand (B)	Revenues: Distribution (C)	Revenues: Total (D)	20% Discount (E)	Discounted Revenue (F)	Distribution Throughput (G)	Rate per Therm (I)	Current Rate per Therm (I)	Percent Increase (J)	Cap Increase (K)	Cap Rates (L)	Final Rates per Therm (M)
1	Medium C&I	$ 5,035,292	$ 10,515,164	$ 15,550,456	$ (3,110,091)	$ 12,440,365	56,381,579	$ 0.2206	0.1923	15%	19%	$ 0.2288	$ 0.2206
2	Large Low Load Factor C&I	$ 2,477,282	$ 4,472,724	$ 6,950,006	$ (1,390,001)	$ 5,560,005	25,898,807	$ 0.2147	0.2015	7%	19%	$ 0.2398	$ 0.2147
3	Large High Load Factor C&I	$ 971,036	$ 1,241,530	$ 2,212,566	$ (442,513)	$ 1,770,053	12,329,000	$ 0.1436	0.1372	5%	19%	$ 0.1633	$ 0.1436
4	Extra Large Low Load Factor C&I	$ 966,585	$ 272,749	$ 1,239,334	$ (247,867)	$ 991,467	8,315,525	$ 0.1192	0.0766	56%	19%	$ 0.0912	$ 0.0912
5	Extra Large High Load Factor C&I	$ 4,027,911	$ 1,334,502	$ 5,362,413	$ (1,072,483)	$ 4,289,930	52,128,989	$ 0.0823	0.0616	34%	19%	$ 0.0733	$ 0.0733

PUC 9-4

Request:

Please clarify the Company's proposal for the recovery of costs related to the proposed low-income discounts for electric and gas. Please identify the appropriate schedule(s).

Response:

As described in the joint pre-filed direct testimony of Company Witnesses Ann E. Leary and Scott M. McCabe on Bates Page 23 of Book 15, the Company is proposing to offer a 15 percent total bill discount to all of its low income customers and to eliminate the current discount reflected by lower base distribution rates for these customers.[1] Specifically, the Company is proposing to set the low income rate class's base distribution rates equal to the corresponding non-discounted residential rates. For Narragansett Electric, the base distribution rates for Rate A-60 will equal those of Rate A-16; for Narragansett Gas, the base distribution rates for Rate 11 will equal those of Rate 10, and the base distribution rates of Rate 13 will equal those of Rate 12. The Company will provide discount based on the total bill by multiplying the total monthly bill by 15 percent. The Company proposes to show the amount of the discount as a line item on customers' bills.

As described in the pre-filed direct testimony of Ms. Leary and Mr. McCabe on Bates Pages 27 and 28 of Book 15, the Company proposes to recover the discount through a Low Income Discount Recovery Factor assessed to all retail delivery service customers except low income customers (customers on Rate A-60, Rate 11, and Rate 13). The Low Income Discount Recovery Factor will be calculated in accordance with the provisions of the proposed Residential Assistance Provision, RIPUC No. 2195 for Narragansett Electric and RIPUC No. 101, Section 7, Schedule C, Item 9.0, for Narragansett Gas. As provided in these tariffs, the discount provided to low income customers will be recovered concurrently based on the estimated annual low income discount. On an annual basis, the actual amount of the discount applied to customer bills will be compared to the amount billed to all other customers through the Low Income Discount Recovery Factor, and any over/under recovery of the discount will credited to or recovered from all other customers through the subsequent year's Low Income Discount Recovery Factor. For Narragansett Electric, the Low Income Discount Recovery Factor will be a uniform per kWh factor included with the distribution kWh rate for billing purposes. For Narragansett Gas, the Low Income Discount Recovery Factor will be a uniform per-therm factor included in the Distribution Adjustment Charge factor for billing purposes. Discounts provided to Rate A-60 customers would be recovered from Narragansett Electric's other customers, and discounts

[1] The Company is also proposing to eliminate the Company's LIHEAP Matching program that is currently available to low income gas heating customers on Rate 13.

provided to Rate 11 and Rate 13 customers would be recovered from Narragansett Gas’s other customers.

PUC 9-5

Request:

The Company has proposed to phase-in the customer charge on the A-60 rate. Please explain how the annual increases to the A-60 customers would be credited to the other applicable customer class(es).

Response:

Pursuant to Narragansett Electric's Revenue Decoupling Mechanism (RDM) Provision, RIPUC No. 2073, Narragansett Electric reconciles actual billed distribution revenue to the annual target revenue approved by the Rhode Island Public Utilities Commission during each 12-month period beginning April 1 (RDM Year), and any difference (either positive or negative) is either recovered from, or returned to, customers through the RDM Adjustment Factor. "Actual Billed Distribution Revenue" includes the amounts Narragansett Electric billed during the applicable RDM Year for customer charges, distribution demand charges, distribution energy charges, Second Feeder Service charges, and any other charges or discounts that Narragansett Electric records as distribution revenue. Thus, any increase in the Rate A-60 customer charge would be reflected in the annual RDM reconciliation, resulting in a lower under-recovered (or higher over-recovered) balance, and in the RDM Adjustment Factor assessed to all customers.

Prepared by or under the supervision of: Scott M. McCabe

PUC 9-6

Request:

If the A-60 rate were designed such that there were still no customer charge and the remaining charges were discounted by 15%, what would be the cost of the discount under the same set of assumptions in the Company proposal compared to the costs included in the Company's proposal? Please include the costs separated by rate year and phase-in years.

Response:

Based upon a scenario where Rate A-60 customers would not be assessed a customer charge, but all other elements of Narragansett Electric's low income discount and rate design proposals are the same (*i.e.*, a 15 percent total bill discount and a distribution energy charge of $0.04159 per kWh per Schedule HSG-4 (REV-1)), the cost of the discount would be less than Narragansett Electric's proposal; however, the amount of the forgone customer charge revenue (i.e., revenue Narragansett Electric would not bill because there would be no customer charge) would be reflected in Narragansett Electric's Revenue Decoupling Mechanism (RDM). This forgone revenue would be permanently reflected in the RDM reconciliation as less revenue that would be paid for by all customers, while Narragansett Electric's phase-in proposal for a Rate A-60 customer charge is a temporary use of the RDM to gradually bring the Rate A-60 customer charge to the same level as that of Rate A-16.

Attachment PUC 9-6 presents the analysis, which compares an estimate of the estimated total cost that customers would see under the scenario posed in this data request and the estimated total cost based on Narragansett Electric's proposal.

Prepared by or under the supervision of: Scott M. McCabe

The Narragansett Electric Company
Comparison of Estimated Low Income Discount Based on
An Illustrative $0 Rate A-60 Customer Charge and the Proposed Rate A-16 Distribiton kWh Charge
And Narragansett Electric's Low Income Discount & Rate Design Proposals

		Rate Year 1 (a)	Year 2 (b)	Year 3 (c)	3-Year Total (d)
(1)	Estimated Annual Low Income Discount Based on Illustrative $0 Customer Charge	$5,940,406	$5,940,406	$5,940,406	
(2)	Estimated Forgone Annual Customer Charge Revenue via RDM	$3,715,955	$3,715,955	$3,715,955	
(3)	Total Estimated Rate A-60 Bill Benefits	$9,656,361	$9,656,361	$9,656,361	$28,969,083
(4)	Estimated Annual Low Income Discount Based on Company's Proposal	$6,120,739	$6,301,072	$6,497,799	
(5)	Estimated Annual Value of Customer Charge Phase-In via RDM	$2,513,734	$1,311,514	$0	
(6)	Total Estimated Rate A-60 Bill Benefits	$8,634,473	$7,612,586	$6,497,799	$22,744,859
(7)	Higher (Lower) Low Income Benefits Paid by All Other Customers	$1,021,888	$2,043,775	$3,158,562	$6,224,225

(1) Page 2, Line (24)
(2) Page 3, Line (1), Column (g)
(3) Line (1) + Line (2)
(4) Page 3, Line (24)
(5) (a): Page 3, Line (1), Column (g) - Column (c)
(b): Page 3, Line (1), Column (g) - Column (e)
(6) Line (4) + Line (5)

The Narragansett Electric Company
Illustrative Calculation of Estimated Rate Year Electric Low Income Discount and Low Income Discount Recovery Factor (LIDRF)
Assuming a $0 Rate A-60 Customer Charge and the Proposed Rate A-16 Distribiton kWh Charge

			Rate Year	
		Rate Year Rate A-60 Units	Illustrative Rate A-60 Rate	Charges
		(a)	(b)	(c)
(1)	Customer Charge	437,171	$0.00	$0
(2)	RE Growth Factor	437,171	$0.78	$340,993
(3)	LIHEAP Enhancement Surcharge	437,171	$0.81	$354,109
(4)	Distribution kWh Charge	223,496,800	$0.04159	$9,295,232
(5)	ISR CapEx Factor	223,496,800	$0.00000	$0
(6)	ISR CapEx Reconciliation Factor	223,496,800	($0.00135)	($301,721)
(7)	ISR O&M Factor	223,496,800	$0.00163	$364,300
(8)	ISR O&M Reconciliation Factor	223,496,800	($0.00001)	($2,235)
(9)	Pension/PBOP Factor	223,496,800	($0.00085)	($189,972)
(10)	Revenue Decoupling Mechanism Adjustment Factor	223,496,800	$0.00118	$263,726
(11)	Storm Fund Replenishment Factor	223,496,800	$0.00288	$643,671
(12)	Low Income Discount Recovery Factor	223,496,800	$0.00000	$0
(13)	Subtotal Distribution Energy Charge			$10,073,001
(14)	Transmission Charge	223,496,800	$0.03180	$7,107,198
(15)	Transition Charge	223,496,800	$0.00057	$127,393
(16)	Energy Efficiency Program Charge	223,496,800	$0.01154	$2,579,153
(17)	Renewable Energy Distribution Charge	223,496,800	$0.00688	$1,537,658
(18)	Total Delivery Service Charges			$22,119,505
(19)	Winter Commodity Charge	108,217,729	$0.09518	$10,300,163
(20)	Summer Commodity Charge	115,279,071	$0.06231	$7,183,039
(21)	Total Commodity Charges	223,496,800		$17,483,202
(22)	Total			$39,602,708
(23)	Proposed Low Income Discount			15.0%
(24)	Annual Estimated Low Income Discount			$5,940,406

(a) Schedule HSG-4-A (REV-1)
(b) Line (1): per PUC 9-6; Line (4): Schedule HSG-4-A (REV-1); all other lines: Workpaper HSG-5 (REV-1), Page 2
(c) Column (a) x Column (b)
(12) Proposing that all A-60 customers are exempt from Low Income Discount Recovery Factor
(13) Sum of Lines (4) through (12)
(18) Sum of Lines (1) through (3) + Line (13) + Sum of Lines (14) through (17)
(21) Line (19) + Line (20)
(22) Line (18) + Line (21)
(23) Company proposal
(24) Line (22) x Line (23)

The Narragansett Electric Company
Calculation of Estimated Rate Year Electric Low Income Discount and Low Income Discount Recovery Factor (LIDRF)
Under Narragansett Electric's Low Income Discount & Rate Design Proposals

			Rate Year		Year 2		Year 3	
		Rate Year Rate A-60 Units	Proposed Rate A-60 Dist Rates	Charges	Proposed Rate A-60 Dist Rates	Charges	Proposed Rate A-60 Dist Rates	Charges
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	Customer Charge	437,171	$2.75	$1,202,221	$5.50	$2,404,441	$8.50	$3,715,955
(2)	RE Growth Factor	437,171	$0.78	$340,993	$0.78	$340,993	$0.78	$340,993
(3)	LIHEAP Enhancement Surcharge	437,171	$0.81	$354,109	$0.81	$354,109	$0.81	$354,109
(4)	Distribution kWh Charge	223,496,800	$0.04159	$9,295,232	$0.04159	$9,295,232	$0.04159	$9,295,232
(5)	ISR CapEx Factor	223,496,800	$0.00000	$0	$0.00000	$0	$0.00000	$0
(6)	ISR CapEx Reconciliation Factor	223,496,800	($0.00135)	($301,721)	($0.00135)	($301,721)	($0.00135)	($301,721)
(7)	ISR O&M Factor	223,496,800	$0.00163	$364,300	$0.00163	$364,300	$0.00163	$364,300
(8)	ISR O&M Reconciliation Factor	223,496,800	($0.00001)	($2,235)	($0.00001)	($2,235)	($0.00001)	($2,235)
(9)	Pension/PBOP Factor	223,496,800	($0.00085)	($189,972)	($0.00085)	($189,972)	($0.00085)	($189,972)
(10)	Revenue Decoupling Mechanism Adjustment Factor	223,496,800	$0.00118	$263,726	$0.00118	$263,726	$0.00118	$263,726
(11)	Storm Fund Replenishment Factor	223,496,800	$0.00288	$643,671	$0.00288	$643,671	$0.00288	$643,671
(12)	Low Income Discount Recovery Factor	223,496,800	$0.00000	$0	$0.00000	$0	$0.00000	$0
(13)	Subtotal Distribution Energy Charge			$10,073,001		$10,073,001		$10,073,001
(14)	Transmission Charge	223,496,800	$0.03180	$7,107,198	$0.03180	$7,107,198	$0.03180	$7,107,198
(15)	Transition Charge	223,496,800	$0.00057	$127,393	$0.00057	$127,393	$0.00057	$127,393
(16)	Energy Efficiency Program Charge	223,496,800	$0.01154	$2,579,153	$0.01154	$2,579,153	$0.01154	$2,579,153
(17)	Renewable Energy Distribution Charge	223,496,800	$0.00688	$1,537,658	$0.00688	$1,537,658	$0.00688	$1,537,658
(18)	Total Delivery Service Charges			$23,321,726		$24,523,946		$25,835,460
(19)	Winter Commodity Charge	108,217,729	$0.09518	$10,300,163	$0.09518	$10,300,163	$0.09518	$10,300,163
(20)	Summer Commodity Charge	115,279,071	$0.06231	$7,183,039	$0.06231	$7,183,039	$0.06231	$7,183,039
(21)	Total Commodity Charges	223,496,800		$17,483,202		$17,483,202		$17,483,202
(22)	Total			$40,804,929		$42,007,148		$43,318,662
(23)	Proposed Low Income Discount			15.0%		15.0%		15.0%
(24)	Annual Estimated Low Income Discount			$6,120,739		$6,301,072		$6,497,799

(a) Schedule HSG-4-A (REV-1)
(b), (d), (f) Line (1): per Company proposal for a 3-year phase-in; Line (4): Schedule HSG-4-A (REV-1); all other lines: Workpaper HSG-5 (REV-1), Page 2
(c), (e), (g) Column (a) x Column (b); Column (a) x Column (d); Column (a) x Column (f)
(12) Proposing that all A-60 customers are exempt from Low Income Discount Recovery Factor
(13) Sum of Lines (4) through (12)
(18) Sum of Lines (1) through (3) + Line (13) + Sum of Lines (14) through (17)
(21) Line (19) + Line (20)
(22) Line (18) + Line (21)
(23) Company proposal
(24) Line (22) x Line (23)

PUC 9-7

Request:

How, if at all, does the proposed flat discount affect A-60 net metering customers? Please provide an example of a low-income net metering bill under the current rate structure and the proposed 15% flat discount.

Response:

Under the current rate structure, net metering customers on Rate A-60 are not assessed a customer charge and are assessed a lower per-kWh base distribution rate than the rate that is billed to Rate A-16 customers. The customer will be assessed the full value of the fixed LIHEAP Enhancement Charge and the RE Growth Charge along with all other rates at the same value as those for Rate A-16 customers. If a net metering customer generates more kWh than ituses over the course of the customer's billing month (*i.e.*, the meter spun backwards more often when generation exceeded the customer's use during the month than when the meter spun forwards to record use off of Narragansett Electric's system), the customer will receive renewable net metering credits based on the per-kWh rates for Standard Offer Service, Distribution, Transmission, and Transition applicable to Rate A-60 customers.[1]

Under the proposed 15 percent discount, the Rate A-60 customer would be assessed a customer charge (proposed at $2.75 in the rate year, $5.50 in year 2, and $8.50 in year 3 and beyond), and receive a 15 percent discount off of the customer's total bill, which includes the customer charge, through the application of the 15 percent total bill discount. If the customer generates more kWh than it uses in a particular month, the renewable net metering credit that the Rate A-60 customer would receive would be based on the per-kWh rates for Standard Offer Service, Distribution, Transmission, and Transition; however, the Distribution component would include a higher per-kWh base distribution rate under the Company's low income discount proposal. In addition, the low income discount would not apply to (i.e., would not reduce) the renewable net metering credit.

Please see Attachment PUC 9-7-1 for three examples of a Rate A-60 net metering customer bill calculation under the current rate structure and the proposed 15 percent discount. Page 1 presents bill calculations for a customer who generates fewer kWh than they use over the course of the customer's billing month. Page 2 presents bill calculations for a customer who generates more kWh than they use during the course of the customer's billing month. Page 3 presents bill calculations for a customer who generates exactly the same amount of kWh that they use during the billing month. For the purpose of these examples, the Company used rates effective as of November 1, 2017, the rates in effect at the time of the Company's initial filing, for the current

[1] Pursuant to Narragansett Electric's Net Metering Provision, RIPUC No. 2178.

structure. To illustrate the impact solely as a result of the proposed 15 percent discount, Narragansett Electric has reflected the same November 1, 2017 rates except for Rate A-60's base distribution rates, which Narragansett Electric redesigned as if the total bill discount approach has been in effect since its 2012 rate case in RIPUC Docket No. 4323. Attachment PUC 9-7-2 presents the calculation of the illustrative residential base distribution rates used in Attachment PUC 9-7-1, Column (d), Line (5) and included in Column (d), Line (8) with the various factors billed out with the base distribution energy charge.

The examples are intended to demonstrate the mechanics of the bill calculations under the two low income discount structures. Pages 1 and 2 of Attachment PUC 9-7-1 reflect the net use of a Rate A-60 customer in months where they are either a net importer of energy or a net exporter of energy, respectively. Resulting bills and the value provided from net metering under the current structure and the proposed discount as well as the comparison between the two will be dependent on the level of a customer's kWh needs and kWh generated in a particular billing month. Narragansett Electric has included the value provided from net metering through each bill calculation, including the value of displaced energy and the renewable generation credits, on Lines (22) – (27) on each page. In the examples presented in Attachment PUC 9-7-1, the proposed low income discount structure has a relatively higher per-kWh value associated with displaced energy and, if applicable, renewable generation credits. However, because the proposed change in the low income discount, which includes the assessment of a customer charge, and the relatively low usage of Rate A-60 net metering customers, the overall benefit between net metering and the low income discount provided to low use Rate A-60 customers is marginally less than under the current discount structure. To date, there are currently approximately 50 Rate A-60 net metering customers. These customers are also eligible to procure net metering credits from community solar projects. This allows for applying net metering credits earned at a large solar project to the customer's bill in exchange for the customer paying the large solar project owner some portion of the net metering credits the customer received.

Prepared by or under the supervision of: Scott McCabe and Timothy Roughan

The Narragansett Electric Company
Illustrative Impact of Proposed Low Income Discount
on a Hypothetical Rate A-60 Net Metering Customer

(1)	Hypothetical Monthly Generation	600					
(2)	Hypothetical On-Site kWh Consumption	720					
(3)	Hypothetical Monthly Net kWh Delivered	120					
(4)	Hypothetical Monthly Exported kWh	0					
		November 1, 2017			Hypothetical November 1, 2017 A-60 Rates w/15% Flat Discount		
		Rate	Billed kWh	Amount	Rate, Year 3	Billed kWh	Amount
		(a)	(b)	(c)	(d)	(e)	(f)
(5)	Customer Charge	$0.00		$0.00	$5.00		$5.00
(6)	RE Growth Program	$0.78		$0.78	$0.78		$0.78
(7)	LIHEAP Enhancement Charge	$0.81		$0.81	$0.81		$0.81
(8)	Distribution Energy Charge	$0.02953	120	$3.54	$0.04087	120	$4.90
(9)	Transmission Charge	$0.03179	120	$3.81	$0.03179	120	$3.81
(10)	Transition Charge	$0.00057	120	$0.07	$0.00057	120	$0.07
(11)	Energy Efficiency Programs	$0.01154	120	$1.38	$0.01154	120	$1.38
(12)	Renewable Energy Distribution Charge	$0.00687	120	$0.82	$0.00687	120	$0.82
(13)	Standard Offer Service (SOS)*	$0.09475	120	$11.37	$0.09475	120	$11.37
(14)	Renewable Energy Standard*	$0.00040	120	$0.05	$0.00040	120	$0.05
(15)	Total Before Proposed Low Income Discount, Gross Earnings Tax (GET), & Renewable Generation Credit	$0.17545		$22.63	$0.18679		$28.99
(16)	Proposed Low Income Discount			n/a	15%		($4.35)
(17)	Total Before GET & Renewable Generation Credit			$22.63			$24.64
(18)	GET			$0.94			$1.03
(19)	Total Before Renewable Generation Credit			$23.57			$25.67
(20)	Renewable Generation Credit (Distribution, Transmission, Transition, SOS)	$0.15664	0	$0.00	$0.16798	0	$0.00
(21)	Total Bill			$23.57			$25.67
(22)	Value of Net Metering						
(23)	Displaced Energy	$0.17545	600	$105.27	$0.18679	600	$112.07
(24)	Impact of Proposed Low Income Discount				15%		($16.81)
(25)	Impact of GET			$4.39			$3.97
(26)	Renewable Generation Credit [-Line (20)]			$0.00			$0.00
(27)	Total			$109.66			$99.23

* Standard Offer Service and Renewable Energy Standard rates are combined on the customer bill

The Narragansett Electric Company
Illustrative Impact of Proposed Low Income Discount
on a Hypothetical Rate A-60 Net Metering Customer

(1)	Hypothetical Monthly Generation	600
(2)	Hypothetical On-Site kWh Consumption	595
(3)	Hypothetical Monthly Net kWh Delivered	0
(4)	Hypothetical Monthly Exported kWh	5

		November 1, 2017			Hypothetical November 1, 2017 A-60 Rates w/15% Flat Discount		
		Rate	Billed kWh	Amount	Rate, Year 3	Billed kWh	Amount
		(a)	(b)	(c)	(d)	(e)	(f)
(5)	Customer Charge	$0.00		$0.00	$5.00		$5.00
(6)	RE Growth Program	$0.78		$0.78	$0.78		$0.78
(7)	LIHEAP Enhancement Charge	$0.81		$0.81	$0.81		$0.81
(8)	Distribution Energy Charge	$0.02953	0	$0.00	$0.04087	0	$0.00
(9)	Transmission Charge	$0.03179	0	$0.00	$0.03179	0	$0.00
(10)	Transition Charge	$0.00057	0	$0.00	$0.00057	0	$0.00
(11)	Energy Efficiency Programs	$0.01154	0	$0.00	$0.01154	0	$0.00
(12)	Renewable Energy Distribution Charge	$0.00687	0	$0.00	$0.00687	0	$0.00
(13)	Standard Offer Service (SOS)*	$0.09475	0	$0.00	$0.09475	0	$0.00
(14)	Renewable Energy Standard*	$0.00040	0	$0.00	$0.00040	0	$0.00
(15)	Total Before Proposed Low Income Discount, Gross Earnings Tax (GET), & Renewable Generation Credit	$0.17545		$1.59	$0.18679		$6.59
(16)	Proposed Low Income Discount			n/a	15%		($0.99)
(17)	Total Before GET & Renewable Generation Credit			$1.59			$5.60
(18)	GET			$0.07			$0.23
(19)	Total Before Renewable Generation Credit			$1.66			$5.83
(20)	Renewable Generation Credit (Distribution, Transmission, Transition, SOS)	$0.15664	(5)	($0.78)	$0.16798	(5)	($0.84)
(21)	Total Bill			$0.88			$4.99
(22)	Value of Net Metering						
(23)	Displaced Energy	$0.17545	595	$104.39	$0.18679	600	$112.07
(24)	Impact of Proposed Low Income Discount				15%		($16.81)
(25)	Impact of GET			$4.35			$3.97
(26)	Renewable Generation Credit [-Line (20)]			$0.78			$0.84
(27)	Total			$109.52			$100.07

* Standard Offer Service and Renewable Energy Standard rates are combined on the customer bill

The Narragansett Electric Company
Illustrative Impact of Proposed Low Income Discount
on a Hypothetical Rate A-60 Net Metering Customer

(1)	Hypothetical Monthly Generation	600
(2)	Hypothetical On-Site kWh Consumption	600
(3)	Hypothetical Monthly Net kWh Delivered	0
(4)	Hypothetical Monthly Exported kWh	0

		November 1, 2017			Hypothetical November 1, 2017 A-60 Rates w/15% Flat Discount		
		Rate	Billed kWh	Amount	Rate, Year 3	Billed kWh	Amount
		(a)	(b)	(c)	(d)	(e)	(f)
(5)	Customer Charge	$0.00		$0.00	$5.00		$5.00
(6)	RE Growth Program	$0.78		$0.78	$0.78		$0.78
(7)	LIHEAP Enhancement Charge	$0.81		$0.81	$0.81		$0.81
(8)	Distribution Energy Charge	$0.02953	0	$0.00	$0.04087	0	$0.00
(9)	Transmission Charge	$0.03179	0	$0.00	$0.03179	0	$0.00
(10)	Transition Charge	$0.00057	0	$0.00	$0.00057	0	$0.00
(11)	Energy Efficiency Programs	$0.01154	0	$0.00	$0.01154	0	$0.00
(12)	Renewable Energy Distribution Charge	$0.00687	0	$0.00	$0.00687	0	$0.00
(13)	Standard Offer Service (SOS)*	$0.09475	0	$0.00	$0.09475	0	$0.00
(14)	Renewable Energy Standard*	$0.00040	0	$0.00	$0.00040	0	$0.00
(15)	Total Before Proposed Low Income Discount, Gross Earnings Tax (GET), & Renewable Generation Credit	$0.17545		$1.59	$0.18679		$6.59
(16)	Proposed Low Income Discount			n/a	15%		($0.99)
(17)	Total Before GET & Renewable Generation Credit			$1.59			$5.60
(18)	GET			$0.07			$0.23
(19)	Total Before Renewable Generation Credit			$1.66			$5.83
(20)	Renewable Generation Credit (Distribution, Transmission, Transition, SOS)	$0.15664	0	$0.00	$0.16798	0	$0.00
(21)	Total Bill			$1.66			$5.83
(22)	Value of Net Metering						
(23)	Displaced Energy	$0.17545	600	$105.27	$0.18679	600	$112.07
(24)	Impact of Proposed Low Income Discount				15%		($16.81)
(25)	Impact of GET			$4.39			$3.97
(26)	Renewable Generation Credit [-Line (20)]			$0.00			$0.00
(27)	Total			$109.66			$99.23

* Standard Offer Service and Renewable Energy Standard rates are combined on the customer bill

The Narragansett Electric Company
Illustrative Rate Design for Residential Rates A-16 / A-60 from Docket 4323
Assuming Rate A-60 Billed at Rate A-16 Rates

		Billing Units	Illustrative Rates	Revenue
		(a)	(b)	(c)
1	Revenue Allocation			$133,620,023
2				
3	Customer Charge:			
4	Monthly Bills- A-16	4,669,275	$5.00	$23,346,375
5	Monthly Bills- A-60	502,672	$5.00	$2,513,360
6	Customer Charge Revenue	5,171,947		$25,859,735
7				
8	Energy-based Charge:			
9	kWh Sales- A-16	2,830,141,506	$0.03451	$97,668,183
10	kWh Sales- A-60	291,989,246	$0.03451	$10,076,549
11	Distribution Charge Revenue	3,122,130,752		$107,744,732
12				
13	Rate A-16 Rev			$121,014,558
14	Rate A-60 Rev			$12,589,909
15				
16	Total Revenue			$133,604,467
17				
18	Difference			($15,556)

All information in Columns (a) through (c) is replicated from the
January 24, 2013 Compliance Filing in Docket 4323, Attachment 3D, Page 2, Line 1

PUC 9-8

Request:

Please explain how income eligible customers are identified in Massachusetts.

a. If one of the means by which income eligible customers are identified is through a data sharing agreement with the Department of Transitional Assistance, please explain how it works, how it was implemented, the costs to implement, any ongoing costs, and the percentage of eligible income customers identified by this mechanism.

b. Does the Company currently engage with any of the Rhode Island governmental agencies to identify income-eligible customers?

c. Does the Company receive enrollment applications from CAP Agencies in Rhode Island?

Response:

In Massachusetts, Massachusetts Electric Company, Nantucket Electric Company, Boston Gas Company, and Colonial Gas Company, each d/b/a National Grid (together, the Massachusetts Companies) identify income-eligible (also called low income) customers through several channels, including:

- Through a customer's direct contact with National Grid's Customer Contact Center;
- Through community outreach by the Consumer Advocates and at Expo events;
- Through fuel assistance agencies' electronic files of customers who receive or are eligible to receive assistance from the Low Income Home Energy Assistance Program (LIHEAP) and are therefore eligible to be served on one of the Massachusetts Companies' low income rate classes; and
- Through an electronic matching process, as established by the Massachusetts Department of Public Utilities (DPU), of the Massachusetts Companies' quarterly lists of residential customers (*i.e.*, customer of record) and those residents receiving a means-tested public benefit as administered by the Massachusetts Executive Office of Health and Human Services (EOHHS) whereby EOHSS performs a matching process between the Massachusetts Companies' list of residential customers and EOHHS's database, and EOHHS sends to the Massachusetts Companies a file of matched names that are then processed to place the respective account on the applicable low income rate class.

Prepared by or under the supervision of: John Isberg

a. Electronic Matching Process

How the data sharing works: At the end of each quarter, reports for each of the Massachusetts Companies containing specific customer data fields are run from the Massachusetts Companies' respective billing systems. The report is provided via electronic file to the EOHHS and the Department of Transitional Assistance (DTA) via Massachusetts' Interchange File Transfer system. The EOHHS/DTA retrieves the files and performs analysis using the DTA database. The Massachusetts Companies are notified when the matching process is complete and retrieve the resulting files via the Interchange File Transfer system. When the files are retrieved by the Massachusetts Companies, a program is run through the respective billing system to identify and update accounts not on a low income rate class to place the account on the appropriate low income rate class.

How it was implemented: The Massachusetts Companies participated in the DPU's generic investigation into expanding the penetration rate of the discount rate (Docket Number D.P.U. 01-106). As part of this investigation, the DPU established a data sharing and matching process with the EOHHS. The EOHHS implemented this program in September of 2005. Quarterly, electronic files are exchanged between the Massachusetts Companies and the EOHHS with the specific purpose of identifying and enrolling customers who qualify for low-income rate classes but who have not previously been enrolled. The program allows the customer to opt out of the matching process.

The costs to implement/ongoing costs: Initial implementation in Massachusetts took place in 2005. At the time, three of the four Massachusetts Companies were operating under long-term rate plans and, therefore, the recovery of implementation costs was not provided for this program. Consequently, the Massachusetts Companies did not specifically track the costs to implement the electronic matching of eligible customers by the EOHHS. Not only did the Massachusetts Companies incur implementation costs, but the EOHHS/DTA also incurred implementation costs. Ongoing costs of administering this enrollment channel are not separately identifiable; however, the Massachusetts Companies do not believe that they comprise a significant amount, as the process has been in place for approximately 13 years and has become a standardized enrollment process.

The percent of customers identified: Approximately 80 percent of gas customers on the Massachusetts Companies' low income gas rate classes and 55 percent of electric customers on the Massachusetts Companies' low income electric rate class are enrolled on the discount rate through the data sharing process.

b. The Rhode Island Department of Human Services provides qualifying recipients with an application for the Company's low income rates. The application is submitted to the Company and the customer is placed on the applicable low income rate if they meet the qualifications required by the low income rate.

c. The Company receives two files each for electric and gas customers from the CAP agencies. The first file identifies payments to be processed on accounts (for LIHEAP) and identifies accounts for which their placement on the low income rate is to be extended or to place an account on the low income rate. The second file identifies accounts for which their placement on the low income rate is to be extended or to place an account on the low income rate.

Prepared by or under the supervision of: John Isberg

PUC 9-9

Request:

Referencing Mr. Athos' supplemental testimony, page 4, he sets forth the changes that have been made to the allocated cost of service study (ACOSS) methodology since the 2012 study. On page 8 of Mr. Athos' testimony and page 12 of his supplemental testimony, he notes the increased costs allocated to residential customers based on number of bills in the "secondary system." In both places he states, "this secondary system cost increase comes in Service Drop-related accounts. This suggests that an increase in monthly fixed charges would be consistent with cost causation principles of a cost of service study."

a. Has National Grid made any other changes to the methodology since the 2012 ACOSS?

b. What has led to the increase in the secondary system costs allocated to residential customers?

c. If so, please identify them and explain why they are reasonable, specifically addressing any demand related costs that may have been allocated differently in the 2017 ACOSS.

Response:

a. No, Narragansett Electric has not changed its allocation methodology from the 2012 Allocated Cost of Service Study (ACOSS).

b. As noted by Mr. Athas, the increase is attributable to higher costs for Service Drops. The embedded cost for Service Drops is allocated based on current costs.

c. The fixed charge computation is based on the ACOSS and is reasonable. Demand-related costs do not affect the fixed charge computation.

Prepared by or under the supervision of: Howard Gorman

PUC 9-10

Request:

Did National Grid do any analysis of the impact on gas heating customers resulting from its proposal to eliminate the tail block pricing structure? If so, what were the results? If not, why not?

Response:

Narragansett Gas compared the Residential Heating (Rate 12) and Residential Heating Low Income (Rate 13) bill impacts based upon delivery rates that included a headblock/tailblock rate structure with the bill impacts based upon Narragansett Gas' proposal to implement a uniform volumetric charge. In Attachment PUC 9-10-1, Narragansett Gas calculates illustrative headblock and tailblock distribution rates for Rate 12 and Rate 13 that would generate the same proposed revenue as shown in Schedule PMN-7 (REV-1), Page 4, Line 75, Column (Z). In Attachment PUC 9-10-2, Narragansett Gas presents the bill impacts for Rate 12 and Rate 13 based upon the illustrative headblock and tailblock rates calculated in Attachment PUC 9-10-1.[1] For Rate 12 customers, the bill impacts utilizing the illustrative headblock/tailblock rates range from 3.7 percent to 5.5 percent as shown in Attachment PUC 9-10-2, while the bill impacts based on Narragansett Gas' proposal to implement a uniform volumetric rate (thereby eliminating the two tier pricing structure) range from 2.9 percent to 3.7 percent as shown in Schedule PMN-8 (REV-1), Page 1, Column (e). For Rate 13 customers, the bill impacts utilizing the illustrative headblock/tailblock rates range from a decrease of 6.2 percent to 8.5 percent as shown in Attachment PUC 9-10-2, while the bill impacts based on Narragansett Gas' proposal to implement a uniform volumetric charge (thereby eliminating the two tier pricing structure) range from a decrease of 8.5 percent to 9.4 percent as shown in Schedule PMN-8 (REV-1), Page 1, Column (e). Therefore, Narragansett Gas' proposal to eliminate the headblock/tailblock rate structure for Rate 12 and Rate 13 will result in more consistent bill increases within each rate class.

[1] The Company maintained the proposed customer charge of $16.00 reflected in Schedule PMN-7 (REV-1).

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Attachment PUC 9-10-1
Page 1 of 4

NG RI PROPOSED GAS RATE DESIGN

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				Weather Normalized Sales											
Rate	CURRENT RATES	Annual Customers	Existing Customer Charge	Sales (therms)	Transp (therms)		Total Therms	Annual Proposed Blocking Therms	First Block % usage	First Block Therms	Tail Block Therms	MADQ Demand Therms	Dist Chrg Head Per Therms	Dist Chrg Tail Per Therms	Demand Per Therms
80	Gas Lights	2,326	$9.52												
10	Residential, Non-Heat	201,541	$13.00	3,673,573	0		3,673,573	NA	100.00%	3,673,573	0		$0.4386		
11	Residential, Low Income Non-Heat	2,492	$11.70	101,774	0		101,774	NA	100.00%	101,774	0		$0.3947		
	Total Non Heat	204,033		3,775,348	0		3,775,348			3,775,348	0				
12	Residential, Heat Peak	1,261,573	$13.00	144,054,319	0		144,054,319	125	74.85%	107,825,814	36,228,505		$0.4672	$0.3010	
12	Residential, Heat Off-Peak	1,258,710	$13.00	33,442,491	0		33,442,491	30	78.60%	26,285,200	7,157,291		$0.4672	$0.3010	
13	Residential, Low Income Heat Peak	103,030	$11.70	11,536,022	0		11,536,022	125	79.11%	9,125,974	2,410,048		$0.4205	$0.2709	
13	Residential, Low Inc Heat Off-Peak	101,871	$11.70	2,725,461	0		2,725,461	30	83.32%	2,270,725	454,736		$0.4205	$0.2709	
	Total Heating	2,725,184		191,758,293	0		191,758,293			145,507,713	46,250,580				
21	Comm & Indust Small Peak	111,874	$22.00	19,048,352	0		19,048,352	135	46.60%	8,877,404	10,170,948		$0.5431	$0.2242	
21	Comm & Indust Small Off-Peak	111,049	$22.00	3,838,817	0		3,838,817	20	32.91%	1,263,285	2,575,531		$0.5431	$0.2242	
21	Comm & Indust Small FT-2 Peak	4,163	$22.00	0	1,392,814		1,392,814	135	46.86%	652,721	740,093		$0.5431	$0.2242	
21	Comm & Indust Small FT-2 Off-Peak	4,231	$22.00	0	351,777		351,777	20	33.66%	118,400	233,376		$0.5431	$0.2242	
	Total Comm & Ind Small	231,317		22,887,169	1,744,590		24,631,759			10,911,811	13,719,949				
22	Comm & Indust Medium Sales	40,181	$70.00	31,579,424	0		31,579,424	NA	100.00%	31,579,424	0	2,412,345	$0.1865		$1.3000
22	Comm & Indust Medium FT-1	3,928	$70.00	0	5,321,965		5,321,965	NA	100.00%	5,321,965	0	398,547	$0.1865		$1.3000
22	Comm & Indust Medium FT-2	18,305	$70.00	0	18,345,461		18,345,461	NA	100.00%	18,345,461	0	1,366,900	$0.1865		$1.3000
22	Total Comm & Indust Medium	62,414		31,579,424	23,667,426		55,246,850			55,246,850	0	4,177,792			
33	Comm & Indust Large LLF Sales	1,404	$175.00	5,970,565	0		5,970,565	NA	100.00%	5,970,565	0	537,935	$0.1727		$1.3000
33	Comm & Indust Large LLF FT-1	1,461	$175.00	0	8,160,548		8,160,548	NA	100.00%	8,160,548	0	652,793	$0.1727		$1.3000
33	Comm & Indust Large LLF FT-2	2,608	$175.00	0	12,236,040		12,236,040	NA	100.00%	12,236,040	0	993,434	$0.1727		$1.3000
33	Total Comm & Ind Large LLF	5,473		5,970,565	20,396,587		26,367,153			26,367,153	0	2,184,163			
23	Comm & Indust Large HLF Sales	670	$175.00	2,712,395	0		2,712,395	NA	100.00%	2,712,395	0	61,187	$0.1007		$1.8000
23	Comm & Indust Large HLF FT-1	1,031	$175.00	0	5,161,579		5,161,579	NA	100.00%	5,161,579	0	258,686	$0.1007		$1.8000
23	Comm & Indust Large HLF FT-2	735	$175.00	0	5,228,802		5,228,802	NA	100.00%	5,228,802	0	241,549	$0.1007		$1.8000
23	Total Comm & Ind Large HLF	2,436		2,712,395	10,390,381		13,102,776			13,102,776	0	561,421			
34	Comm & Ind Extra Large LLF Sales	48	$425.00	428,805	0		428,805	NA	100.00%	428,805	0	43,562	$0.0328		$1.3000
34	Comm & Ind Extra Large LLF FT-1	324	$425.00	0	11,221,498		11,221,498	NA	100.00%	11,221,498	0	779,109	$0.0328		$1.3000
34	Comm & Ind Extra Large LLF FT-2	36	$425.00	0	581,031		581,031	NA	100.00%	581,031	0	39,201	$0.0328		$1.3000
34	Tot Com & Ind Extra Large LLF	408		428,805	11,802,529		12,231,334			12,231,334	0	861,871			
24	Comm & Ind Extra Large HLF Sales	36	$425.00	761,197	0		761,197	NA	100.00%	761,197	0	67,357	$0.0256		$1.8000
24	Comm & Ind Extra Large HLF FT-1	888	$425.00	0	63,406,498		63,406,498	NA	100.00%	63,406,498	0	2,339,952	$0.0256		$1.8000
24	Comm & Ind Extra Large HLF FT-2	192	$425.00	0	5,443,394		5,443,394	NA	100.00%	5,443,394	0	266,355	$0.0256		$1.8000
24	Tot Com & Ind Extra Large HLF	1,116		761,197	68,849,892		69,611,089			69,611,089	0	2,673,665			
	Total	3,232,381		259,873,195	136,851,405		396,724,601			336,754,072	59,970,529	10,458,912			
		Excl Lghts									396,724,601				

NG RI PROPOSED GAS RATE DESIGN

Rate	(A) CURRENT RATES	(P) Existing Base Revenues	(Q) RDM & ISR Adjust & Norm ERC	(R) Present Sales Revenues	(S) Cost of Service Results: Existing ROR	(T) Cost of Service Results: Equalized ROR 7.67% Rev Req	(U) Revenue Increase to Equalize Col T - R	(V) Percent Increase Equal ROR	(W) Proposed Increases Capped @ 10.03%	(X) Shortfall $ Allocation on Equalized ROR Rev	(Y) Prelim Class Increase	(Z) Initial Target Rev Req for Class	(AA) Prelim Base Percent Increase
80	Gas Lights	$22,148		$22,148		$37,084	$14,936	67.44%	$2,222		$2,222	$24,370	10.03%
10	Residential, Non-Heat	$4,231,262	$441,706	$4,672,968		$7,084,657	$2,411,689	51.61%	$468,739		$468,739	$5,141,707	10.03%
11	Residential, Low Income Non-Heat	$69,327	$12,237	$81,564		$116,078	$34,514	42.32%	$8,182		$8,182	$89,745	10.03%
	Total Non Heat	$4,322,737	$453,943	$4,776,680	-2.08%	$7,237,819	$2,461,139	51.52%	$479,142		$479,142	$5,255,822	10.03%
12	Residential, Heat Peak	$77,681,449	$17,320,898	$95,002,347		$101,468,152	$6,465,805	6.81%	$7,457,915	$244,248	$7,702,163	$102,704,510	8.11%
12	Residential, Heat Off-Peak	$30,798,020	$4,021,080	$34,819,100		$40,228,629	$5,409,528	15.54%	$3,492,657	$96,836	$3,589,493	$38,408,593	10.31%
13	Residential, Low Income Heat Peak	$5,695,805	$1,387,076	$7,082,881		$7,439,908	$357,027	5.04%	$556,023	$17,909	$573,932	$7,656,813	8.10%
13	Residential, Low Inc Heat Off-Peak	$2,269,919	$327,706	$2,597,624		$2,964,986	$367,362	14.14%	$260,564	$7,137	$267,701	$2,865,326	10.31%
	Total Heating	$116,445,193	$23,056,760	$139,501,953	5.69%	$152,101,675	$12,599,722	9.03%	$11,767,160	$366,130	$12,133,289	$151,635,242	8.70%
21	Comm & Indust Small Peak	$9,562,873	$2,278,914	$11,841,787		$13,682,882	$1,841,096	15.55%	$1,187,834		$1,187,834	$13,029,621	10.03%
21	Comm & Indust Small Off-Peak	$3,706,602	$459,270	$4,165,872		$5,303,532	$1,137,660	27.31%	$417,873		$417,873	$4,583,745	10.03%
21	Comm & Indust Small FT-2 Peak	$612,007	$166,634	$778,641		$875,681	$97,040	12.46%	$78,104		$78,104	$856,746	10.03%
21	Comm & Indust Small FT-2 Off-Peak	$209,708	$42,086	$251,794		$300,058	$48,263	19.17%	$25,257		$25,257	$277,051	10.03%
	Total Comm & Ind Small	$14,091,191	$2,946,904	$17,038,095	3.75%	$20,162,153	$3,124,059	18.34%	$1,709,068		$1,709,068	$18,747,163	10.03%
22	Comm & Indust Medium Sales	$11,838,281	$2,716,574	$14,554,855		$14,983,945	$429,089	2.95%	$1,142,591	$36,068	$1,178,660	$15,733,515	8.10%
22	Comm & Indust Medium FT-1	$1,785,617	$457,814	$2,243,431		$2,260,090	$16,659	0.74%	$176,115	$5,440	$181,555	$2,424,986	8.09%
22	Comm & Indust Medium FT-2	$6,479,749	$1,578,142	$8,057,891		$8,201,545	$143,655	1.78%	$632,564	$19,742	$652,306	$8,710,197	8.10%
22	Total Comm & Indust Medium	$20,103,647	$4,752,530	$24,856,177	7.18%	$25,445,580	$589,403	2.37%	$1,951,270	$61,251	$2,012,521	$26,868,698	8.10%
								Minimum	7.85%				
33	Comm & Indust Large LLF Sales	$1,976,132	$530,218	$2,506,350		$2,441,831	($64,519)	-2.57%	$196,755	$5,878	$202,632	$2,708,983	8.08%
33	Comm & Indust Large LLF FT-1	$2,513,632	$724,700	$3,238,332		$3,106,000	($132,333)	-4.09%	$254,217	$7,477	$261,694	$3,500,026	8.08%
33	Comm & Indust Large LLF FT-2	$3,861,029	$1,086,625	$4,947,654		$4,770,926	($176,728)	-3.57%	$388,403	$11,484	$399,887	$5,347,541	8.08%
33	Total Comm & Ind Large LLF	$8,350,794	$2,341,543	$10,692,336	8.35%	$10,318,757	($373,579)	-3.49%	$839,374	$24,839	$864,213	$11,556,549	8.08%
								Minimum	7.85%				
23	Comm & Indust Large HLF Sales	$500,525	$188,774	$689,299		$751,270	$61,971	8.99%	$61,971		$61,971	$751,270	8.99%
23	Comm & Indust Large HLF FT-1	$1,165,831	$359,229	$1,525,060		$1,749,871	$224,811	14.74%	$152,977		$152,977	$1,678,037	10.03%
23	Comm & Indust Large HLF FT-2	$1,089,953	$363,908	$1,453,861		$1,635,981	$182,120	12.53%	$145,835		$145,835	$1,599,695	10.03%
23	Total Comm & Ind Large HLF	$2,756,308	$911,911	$3,668,219	5.57%	$4,137,121	$468,902	12.78%	$360,783		$360,783	$4,029,002	9.84%
34	Comm & Ind Extra Large LLF Sales	$91,095	$10,367	$101,462		$100,544	($919)	-0.91%	$7,965	$242	$8,207	$109,669	8.09%
34	Comm & Ind Extra Large LLF FT-1	$1,518,606	$271,299	$1,789,906		$1,676,118	($113,787)	-6.36%	$140,512	$4,035	$144,547	$1,934,452	8.08%
34	Comm & Ind Extra Large LLF FT-2	$85,319	$14,047	$99,366		$94,168	($5,198)	-5.23%	$7,800	$227	$8,027	$107,393	8.08%
34	Tot Com & Ind Extra Large LLF	$1,695,020	$295,714	$1,990,734	8.91%	$1,870,830	($119,904)	-6.02%	$156,277	$4,503	$160,781	$2,151,514	8.08%
								Minimum	7.85%				
24	Comm & Ind Extra Large HLF Sales	$156,030	$15,890	$171,920		$180,573	$8,652	5.03%	$13,496	$435	$13,931	$185,851	8.10%
24	Comm & Ind Extra Large HLF FT-1	$6,212,521	$1,323,629	$7,536,150		$7,189,715	($346,434)	-4.60%	$591,606	$17,307	$608,913	$8,145,062	8.08%
24	Comm & Ind Extra Large HLF FT-2	$700,390	$113,632	$814,023		$810,558	($3,465)	-0.43%	$63,903	$1,951	$65,854	$879,877	8.09%
24	Tot Com & Ind Extra Large HLF	$7,068,941	$1,453,151	$8,522,092	8.46%	$8,180,845	($341,247)	-4.00%	$669,005	$19,692	$688,697	$9,210,790	8.08%
								Minimum	7.85%				
	Total	$174,833,830	$36,212,456	$211,046,286	5.81%	$229,454,781	$18,408,495	8.72%	$17,932,080	$476,415	$18,408,495	$229,454,781	8.72%
							115% cap	1.15	$476,415				
							Capped Incr. on Base $$	10.03%	$ Rev shortfall due to cap				
							90% minimum	0.90					
							Minumum Incr. on Base $$	7.85%					

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Attachment PUC 9-10-1
Page 2 of 4

NG RI PROPOSED GAS RATE DESIGN

57		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
58																
59					Cost Study											
60				Existing	@ Equalized	Proposed	Existing Dist Charges		Proposed Charges				Equal %			
61			Annual	Customer	ROR	Customer	Head Per	Tail Per	Therm Blocks			Average	Block	Proposed	Existing	
62			Customers	Charge	Cust $ (1)	Charges	Therms	Therms	First	Second	MDD	Rate	Increase	RORs		
63	80	Gas Lights	2,326	$9.52	$29.45	$10.47										
64	10	Residential, Non-Heat	201,541	$13.00	$29.45	$16.00	$0.4386		$0.5209			$0.5218			-2.08%	
65	11	Residential, Low Income Non-Heat	2,492	$11.70	$29.45	$16.00	$0.3947		$0.5209			$0.4900			-2.08%	
66		Total Non Heat	204,033						$0.5209			$0.5210		-0.18%	-2.08%	
67																
68	12	Residential, Heat Peak	1,261,573	$13.00	$29.65	$16.00	$0.4672	$0.3010	$0.6032	$0.4359		$0.5724			5.69%	
69	12	Residential, Heat Off-Peak	1,258,710	$13.00	$29.65	$16.00	$0.4672	$0.3010	$0.6032	$0.4359		$0.5455			5.69%	
70		Total Residential Heat	2,520,283	$13.00	$29.65	$16.00	$0.4672	$0.3010	$0.6032	$0.4359		$0.5673		7.58%	5.69%	
71																
72	13	Residential, Low Income Heat Peak	103,030	$11.70	$29.65	$16.00	$0.4205	$0.2709	$0.6032	$0.4359		$0.5204			5.69%	
73	13	Residential, Low Inc Heat Off-Peak	101,871	$11.70	$29.65	$16.00	$0.4205	$0.2709	$0.6032	$0.4359		$0.4526			5.69%	
74		Total Heating Low Income	204,901	$11.70	$29.65	$16.00	$0.4205	$0.2709	$0.6032	$0.4359		$0.5074		7.58%	5.69%	
75		Total Residential Heating	2,725,184			$16.00			$0.6032	$0.4359		$0.5629	1.291			
76																
77	21	Comm & Indust Small Peak	111,874	$22.00	$47.25	$30.25	$0.5431	$0.2242	$0.4770			$0.5064			3.75%	
78	21	Comm & Indust Small Off-Peak	111,049	$22.00	$47.25	$30.25	$0.5431	$0.2242	$0.4770			$0.3190			3.75%	
79	21	Comm & Indust Small FT-2 Peak	4,163	$22.00	$47.25	$30.25	$0.5431	$0.2242	$0.4770			$0.5247			3.75%	
80	21	Comm & Indust Small FT-2 Off-Peak	4,231	$22.00	$47.25	$30.25	$0.5431	$0.2242	$0.4770			$0.4237			3.75%	
81		Total Comm & Ind Small	231,317	$22.00	$47.25	$30.25	$0.5431	$0.2242	$0.4770			$0.4770		5.89%	3.75%	
82								Demand			Prop Dem					
83	22	Comm & Indust Medium Sales	40,181	$70.00	$111.42	$85.00	$0.1865	$1.30	$0.2765		$1.50				7.18%	
84	22	Comm & Indust Medium FT-1	3,928	$70.00	$111.42	$85.00	$0.1865	$1.30	$0.2765		$1.50				7.18%	
85	22	Comm & Indust Medium FT-2	18,305	$70.00	$111.42	$85.00	$0.1865	$1.30	$0.2765		$1.50				7.18%	
86	22	Total Comm & Indust Medium	62,414	$70.00	$111.42	$85.00	$0.1865	$1.30	$0.2765		$1.50			8.83%	7.18%	
87																
88	33	Comm & Indust Large LLF Sales	1,404	$175.00	$227.53	$200.00	$0.1727	$1.30	$0.2722		$1.50				8.35%	
89	33	Comm & Indust Large LLF FT-1	1,461	$175.00	$227.53	$200.00	$0.1727	$1.30	$0.2722		$1.50				8.35%	
90	33	Comm & Indust Large LLF FT-2	2,608	$175.00	$227.53	$200.00	$0.1727	$1.30	$0.2722		$1.50				8.35%	
91	33	Total Comm & Ind Large LLF	5,473	$175.00	$227.53	$200.00	$0.1727	$1.30	$0.2722		$1.50			9.89%	8.35%	
92																
93	23	Comm & Indust Large HLF Sales	670	$175.00	$201.81	$200.00	$0.1007	$1.80	$0.1824		$2.05				5.57%	
94	23	Comm & Indust Large HLF FT-1	1,031	$175.00	$201.81	$200.00	$0.1007	$1.80	$0.1824		$2.05				5.57%	
95	23	Comm & Indust Large HLF FT-2	735	$175.00	$201.81	$200.00	$0.1007	$1.80	$0.1824		$2.05				5.57%	
96	23	Total Comm & Ind Large HLF	2,436	$175.00	$201.81	$200.00	$0.1007	$1.80	$0.1824		$2.05			7.18%	5.57%	
97																
98	34	Comm & Ind Extra Large LLF Sales	48	$425.00	$516.08	$500.00	$0.0328	$1.30	$0.0534		$1.50				8.91%	
99	34	Comm & Ind Extra Large LLF FT-1	324	$425.00	$516.08	$500.00	$0.0328	$1.30	$0.0534		$1.50				8.91%	
100	34	Comm & Ind Extra Large LLF FT-2	36	$425.00	$516.08	$500.00	$0.0328	$1.30	$0.0534		$1.50				8.91%	
101	34	Tot Com & Ind Extra Large LLF	408	$425.00	$516.08	$500.00	$0.0328	$1.30	$0.0534		$1.50			10.55%	8.91%	
102																
103	24	Comm & Ind Extra Large HLF Sales	36	$425.00	$539.76	$500.00	$0.0256	$1.80	$0.0454		$2.05				8.46%	
104	24	Comm & Ind Extra Large HLF FT-1	888	$425.00	$539.76	$500.00	$0.0256	$1.80	$0.0454		$2.05				8.46%	
105	24	Comm & Ind Extra Large HLF FT-2	192	$425.00	$539.76	$500.00	$0.0256	$1.80	$0.0454		$2.05				8.46%	
106	24	Tot Com & Ind Extra Large HLF	1,116	$425.00	$539.76	$500.00	$0.0256	$1.80	$0.0454		$2.05			10.03%	8.46%	
107																
108		Total	3,232,381								system avg.			7.65%	5.81%	
109		check									108.72%					
110																
111		(1) Schedule PMN-5, Page 5, Line 20														

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Attachment PUC 9-10-1
Page 3 of 4

NG RI PROPOSED GAS RATE DESIGN

Line	Rate	(A)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
58														
59								Less					Target	Final
60				Proposed Revenue Recovery			Total	Non-Firm		$ Variance	Final		Revenue	Base
61			Customer	Therms	Therms		Revenues	Revenue	Class Target	to target with	Class		Requirement	Percent
62			Charges	First Block	2nd Block	MDD	@ Prop Rates	Increase	Rev Req	& Discount	Increase		By Class	Increase
63	80	Gas Lights	$24,370				$24,370		$24,370		$2,222		$24,370	10.03%
64	10	Residential, Non-Heat	$3,224,656	$1,913,564			$5,138,220		$5,141,707	-$3,487	$465,253		$5,138,220	9.96%
65	11	Residential, Low Income Non-Heat	$39,872	$53,014			$92,886		$89,745	$3,141	$11,322		$92,886	13.88%
66		Total Non Heat	$3,288,898	$1,966,579			$5,255,476	$0	$5,255,822	-$346	$478,796		$5,255,476	10.02%
67														
68	12	Residential, Heat Peak	$20,185,168	$65,040,531	$15,792,005		$101,017,704	($67,931)	$102,636,579	-$1,618,875	$6,015,357		$101,017,704	6.33%
69	12	Residential, Heat Off-Peak	$20,139,360	$15,855,233	$3,119,863		$39,114,456	($24,897)	$38,383,696	$730,760	$4,295,356		$39,114,456	12.34%
70		Total Residential Heat	$40,324,528	$80,895,764	$18,911,868		$140,132,160	($92,828)	$141,020,275	-$888,115	$10,310,712		$140,132,160	7.94%
71														
72	13	Residential, Low Income Heat Peak	$1,648,480	$5,504,787	$1,050,540		$8,203,807	($5,065)	$7,651,748	$552,059	$1,120,927		$8,203,807	15.83%
73	13	Residential, Low Inc Heat Off-Peak	$1,629,936	$1,369,701	$198,219		$3,197,857	($1,857)	$2,863,468	$334,389	$600,232		$3,197,857	23.11%
74		Total Heating Low Income	$3,278,416	$6,874,489	$1,248,759		$11,401,664	($6,922)	$10,515,217	$886,447	$1,721,159		$11,401,664	17.78%
75		Total Residential Heating	$43,602,944	$87,770,253			$151,533,824	($99,750)	$151,535,492	-$1,668	$12,031,871		$151,533,824	8.62%
76														
77	21	Comm & Indust Small Peak	$3,384,189	$9,086,064			$12,470,252		$13,029,621	-$559,368	$628,465		$12,470,252	5.31%
78	21	Comm & Indust Small Off-Peak	$3,359,232	$1,831,116			$5,190,348		$4,583,745	$606,602	$1,024,476		$5,190,348	24.59%
79	21	Comm & Indust Small FT-2 Peak	$125,931	$664,372			$790,303		$856,746	-$66,443	$11,662		$790,303	1.50%
80	21	Comm & Indust Small FT-2 Off-Peak	$127,988	$167,797			$295,785		$277,051	$18,734	$43,991		$295,785	17.47%
81		Total Comm & Ind Small	$6,997,339	$11,749,349			$18,746,688	$0	$18,747,163	-$475	$1,708,593		$18,746,688	10.03%
82														
83	22	Comm & Indust Medium Sales	$3,415,385	$8,731,711		$3,618,518	$15,765,613	($10,407)	$15,723,108	$42,506	$1,210,758		$15,765,613	8.32%
84	22	Comm & Indust Medium FT-1	$333,880	$1,471,523		$597,820	$2,403,223	($1,604)	$2,423,382	-$20,159	$159,792		$2,403,223	7.12%
85	22	Comm & Indust Medium FT-2	$1,555,925	$5,072,520		$2,050,351	$8,678,795	($5,762)	$8,704,435	-$25,640	$620,905		$8,678,795	7.71%
86	22	Total Comm & Indust Medium	$5,305,190	$15,275,754		$6,266,688	$26,847,632	($17,773)	$26,850,925	-$3,293	$1,991,455		$26,847,632	8.01%
87														
88	33	Comm & Indust Large LLF Sales	$280,800	$1,625,188		$806,903	$2,712,891	($1,792)	$2,707,190	$5,700	$206,541		$2,712,891	8.24%
89	33	Comm & Indust Large LLF FT-1	$292,200	$2,221,301		$979,189	$3,492,690	($2,316)	$3,497,710	-$5,020	$254,358		$3,492,690	7.85%
90	33	Comm & Indust Large LLF FT-2	$521,600	$3,330,650		$1,490,152	$5,342,402	($3,538)	$5,344,003	-$1,602	$394,748		$5,342,402	7.98%
91	33	Total Comm & Ind Large LLF	$1,094,600	$7,177,139		$3,276,244	$11,547,983	($7,645)	$11,548,904	-$921	$855,647		$11,547,983	8.00%
92														
93	23	Comm & Indust Large HLF Sales	$134,000	$494,741		$125,433	$754,174		$751,270	$2,904	$64,875		$754,174	9.41%
94	23	Comm & Indust Large HLF FT-1	$206,200	$941,472		$530,306	$1,677,978		$1,678,037	-$59	$152,918		$1,677,978	10.03%
95	23	Comm & Indust Large HLF FT-2	$147,000	$953,733		$495,174	$1,595,908		$1,599,695	-$3,787	$142,047		$1,595,908	9.77%
96	23	Total Comm & Ind Large HLF	$487,200	$2,389,946		$1,150,914	$4,028,060	$0	$4,029,002	-$942	$359,841		$4,028,060	9.81%
97														
98	34	Comm & Ind Extra Large LLF Sales	$24,000	$22,898		$65,343	$112,241	($73)	$109,597	$2,644	$10,779		$112,241	10.62%
99	34	Comm & Ind Extra Large LLF FT-1	$162,000	$599,228		$1,168,663	$1,929,891	($1,280)	$1,933,172	-$3,281	$139,985		$1,929,891	7.82%
100	34	Comm & Ind Extra Large LLF FT-2	$18,000	$31,027		$58,801	$107,828	($71)	$107,322	$506	$8,462		$107,828	8.52%
101	34	Tot Com & Ind Extra Large LLF	$204,000	$653,153		$1,292,806	$2,149,959	($1,423)	$2,150,091	-$132	$159,226		$2,149,959	8.00%
102														
103	24	Comm & Ind Extra Large HLF Sales	$18,000	$34,558		$138,083	$190,641	($123)	$185,728	$4,913	$18,721		$190,641	10.89%
104	24	Comm & Ind Extra Large HLF FT-1	$444,000	$2,878,655		$4,796,903	$8,119,558	($5,389)	$8,139,674	-$20,116	$583,408		$8,119,558	7.74%
105	24	Comm & Ind Extra Large HLF FT-2	$96,000	$247,130		$546,028	$889,158	($582)	$879,295	$9,864	$75,136		$889,158	9.23%
106	24	Tot Com & Ind Extra Large HLF	$558,000	$3,160,343		$5,481,013	$9,199,357	($6,094)	$9,204,696	-$5,339	$677,264		$9,199,357	7.95%
107														
108		Total	$61,538,171	$130,142,516	$20,160,628	$17,467,665	$229,308,980	($132,686)	$229,322,095	-$13,115	$18,262,694		$229,308,980	8.65%
109		check						($132,686)						
110														
111		(1) Schedule PMN-5, Page 5, Line 20												

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Attachment PUC 9-10-1
Page 4 of 4

National Grid - RI Gas Bill Impact Analysis with Various Levels of Consumption:

Residential Heating:

Line No.		Annual Consumption (Therms)	Proposed Rates [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
5		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
7		548	$911.31	$864.16	$47.15	5.5%	$110.52	($1.83)	$4.52	($66.92)	($0.56)	$0.00	$1.41
8		608	$987.69	$939.43	$48.26	5.1%	$118.68	($1.99)	$4.98	($74.25)	($0.61)	$0.00	$1.45
9		667	$1,062.95	$1,013.58	$49.37	4.9%	$126.70	($2.20)	$5.47	($81.43)	($0.65)	$0.00	$1.48
10		726	$1,136.31	$1,085.88	$50.42	4.6%	$134.71	($2.40)	$5.96	($88.64)	($0.72)	$0.00	$1.51
11		785	$1,208.12	$1,156.69	$51.43	4.4%	$142.71	($2.59)	$6.42	($95.86)	($0.79)	$0.00	$1.54
12	**Average Customer**	**845**	**$1,279.17**	**$1,226.67**	**$52.50**	**4.3%**	$150.83	($2.78)	$6.91	($103.18)	($0.85)	$0.00	$1.58
13		905	$1,350.18	$1,296.59	$53.59	4.1%	$158.95	($2.98)	$7.41	($110.49)	($0.91)	$0.00	$1.61
14		964	$1,419.93	$1,365.30	$54.64	4.0%	$166.94	($3.17)	$7.90	($117.71)	($0.96)	$0.00	$1.64
15		1,023	$1,489.34	$1,433.66	$55.68	3.9%	$174.92	($3.36)	$8.37	($124.92)	($1.00)	$0.00	$1.67
16		1,082	$1,557.89	$1,501.17	$56.72	3.8%	$182.90	($3.57)	$8.88	($132.12)	($1.07)	$0.00	$1.70
17		1,142	$1,627.04	$1,569.25	$57.79	3.7%	$191.01	($3.78)	$9.40	($139.44)	($1.13)	$0.00	$1.73

Residential Heating Low Income:

Line No.		Annual Consumption (Therms)	Proposed Rates [1]	Current Rates [1]	Difference	% Chg	Difference due to: Base Rates	Total Bill Discount	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
22		548	$770.57	$821.75	($51.18)	-6.2%	$151.67	($131.90)	($1.83)	($0.10)	($66.92)	($0.56)	$0.00	($1.54)
23		608	$835.06	$894.19	($59.13)	-6.6%	$162.56	($142.94)	($1.99)	($0.12)	($74.25)	($0.61)	$0.00	($1.77)
24		667	$898.60	$965.55	($66.95)	-6.9%	$173.28	($153.82)	($2.20)	($0.13)	($81.43)	($0.65)	$0.00	($2.01)
25		726	$960.51	$1,035.26	($74.75)	-7.2%	$183.82	($164.42)	($2.40)	($0.15)	($88.64)	($0.72)	$0.00	($2.24)
26		785	$1,021.13	$1,103.62	($82.49)	-7.5%	$194.19	($174.79)	($2.59)	($0.17)	($95.86)	($0.79)	$0.00	($2.47)
27	**Average Customer**	**845**	**$1,081.09**	**$1,171.30**	**($90.21)**	**-7.7%**	$204.53	($185.06)	($2.78)	($0.17)	($103.18)	($0.85)	$0.00	($2.71)
28		905	$1,140.99	$1,238.94	($97.95)	-7.9%	$214.87	($195.31)	($2.98)	($0.19)	($110.49)	($0.91)	$0.00	($2.94)
29		964	$1,199.85	$1,305.40	($105.56)	-8.1%	$225.03	($205.39)	($3.17)	($0.20)	($117.71)	($0.96)	$0.00	($3.17)
30		1,023	$1,258.43	$1,371.56	($113.13)	-8.2%	$235.16	($215.41)	($3.36)	($0.20)	($124.92)	($1.00)	$0.00	($3.39)
31		1,082	$1,316.25	$1,436.95	($120.70)	-8.4%	$245.19	($225.31)	($3.57)	($0.20)	($132.12)	($1.07)	$0.00	($3.62)
32		1,142	$1,374.58	$1,502.93	($128.35)	-8.5%	$255.34	($235.30)	($3.78)	($0.19)	($139.44)	($1.13)	$0.00	($3.85)

Footnote 1 - See Page 6 for detail of proposed and current rates used in bill impacts

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Attachment PUC 9-10-2
Page 1 of 1

PUC 9-11

Request:

Did National Grid do any analysis of the impact on low-income gas heating customers resulting from its proposal to eliminate the tail block pricing structure? If so, what were the results? If not, why not?

Response:

Please see Company's response to PUC 9-10.

Prepared by or under the supervision of: Paul Normand

PUC 9-12

Request:

Please quantify or explain how the increase in the customer charge by the various rate classes per month on the electric bill will affect the Company's ability to achieve its energy efficiency goals.

a. How will the change effect the payback period for energy efficiency investments?

b. If the change will decrease investment in energy efficiency relative to no change, what is the decrease in net benefits, and what is the value of distribution investments that will be necessary due to this decrease in energy efficiency?

Response:

a. The customer charge is not included in the payback calculation for energy efficiency investments quoted to the customer. The customer must pay the customer charge whether or not they invest in energy efficiency.

b. An increase in fixed charges combined with a decrease in variable charges may reduce the amount of total bill savings a customer receives from investment in energy efficiency measures; however, the Company does not anticipate the proposed changes are large enough to create a decrease in investments in energy efficiency.

Prepared by or under the supervision of: John Isberg

PUC 9-13

Request:

Please quantify or explain how the increase in the customer charge by the various rate classes per month on the electric bill will affect the growth of net metering adoption in Rhode Island. How will the change effect the payback period for renewable energy investments?

Response:

Narragansett Electric does not have sufficient information to allow it to determine how its proposed rates will affect the growth of net metering adoption in Rhode Island.

Narragansett Electric has proposed increases to its customer charges for the reasons discussed in the pre-filed direct testimony and rebuttal testimony of Company Witness Howard S. Gorman as consistent with the goals and principles of sound ratemaking practices. Narragansett Electric has also proposed increases in its distribution energy (kWh) rates to recover the remaining class distribution revenue requirement not recovered through customer charges and, for the medium and large commercial and industrial rate classes, demand (kW) charges. It is not appropriate to evaluate in isolation the impact of any change.

Narragansett Electric believes that customers decide to proceed with renewable energy (and other) investments based on many factors and considerations, in addition to the rates and charges in the applicable tariffs.

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

PUC 9-14

Request:

Please quantify or explain how the increase in the customer charge by the various rate classes per month on the gas bill will affect the Company's ability to achieve its energy efficiency goals.

a. How will the change effect the payback period for energy efficiency investments?

b. If the change will decrease investment in energy efficiency relative to no change, what is the decrease in net benefits, and what is the value of distribution investments that will be necessary due to this decrease in energy efficiency

Response:

a. The customer charge is not included in the payback calculation for energy efficiency investments quoted to the customer. The customer must pay the customer charge whether or not they invest in energy efficiency.

b. An increase in fixed charges combined with a decrease in variable charges may reduce the amount of total bill savings a customer receives from investment in energy efficiency measures; however, the Company does not anticipate the proposed changes are large enough to create a decrease in investments in energy efficiency.

Prepared by or under the supervision of: John Isberg

PUC 9-15

Request:

Does an increased customer charge affect the Company's ability to meet demand reduction goals?

Response:

No. The proposed increased customer charge will not affect the Company's ability to meet demand reduction goals.

Prepared by or under the supervision of: John Isberg

PUC 9-16

Request:

Does the ACOSS assume that there are different customer costs associated with residential customers living in single-family or multi-family dwellings or does it assume the costs associated with all A-16 or A-60 customers are the same for purposes of allocating costs?

Response:

Under average cost ratemaking, the Allocated Cost of Service Study uses the weighted average of all Service Drop costs and Meter costs for each rate class.

Prepared by or under the supervision of: Howard Gorman

PUC 9-17

Request:

Has the Company performed of any analysis of whether there are any differences in the cost of connecting the average low-income customer versus other customers? If so, please identify and summarize.

Response:

Narragansett Electric has not performed an analysis of whether there are any differences in the cost of connecting the average low-income customer versus other residential customers.

Prepared by or under the supervision of: Howard Gorman

PUC 9-18

Request:

Has the Company performed any analysis of whether there are different costs of connecting multi-family dwellings versus single family?

a. If so, please identify and summarize and indicate whether the analysis of multi-family dwellings differentiates by overall size (ex: 4 dwelling units versus 50).

b. What proportion of the company's customers live in multi-family housing?

c. Do the Company's multi-family housing customers use more or less electricity than the average residential customer?

Response:

Narragansett Electric has not performed an analysis of whether there are different costs for connecting multi-family dwellings versus single family dwellings. Narragansett Electric does not track what proportion of its customers live in multi-family housing and has not performed an analysis of the levels of electricity usage for multi-family housing customers.

Prepared by or under the supervision of: Howard Gorman

PUC 9-19

Request:

Using residential customer usage for the Test Year, how many A-16 would have higher bills, and how many would have lower bills if the proposed changes to the customers charges were in effect. Please break out the higher and lower results into at least five bins.

Response:

The requested information is contained in Narragansett Electric's April 3, 2018 version of Schedule HSG-5-A (REV-1), which is provided as Attachment PUC 9-19.

Narragansett Electric's proposal increases both components of Rate A-16 (*i.e.*, the fixed monthly charge and the per-kWh distribution rate). Therefore, all customers will see a bill increase.

Prepared by or under the supervision of: Howard Gorman

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-A (REV-1)
Sheet 1 of 1

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed Rates
Rates Applicable to A-16 Rate Customers

	Rates Effective November 1, 2017				Proposed Rates				Increase (Decrease)								
									$				% of Total Bill				
Monthly kWh	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Percentage of Customers
150	$20.66	$14.27	$1.46	$36.39	$24.61	$14.28	$1.62	$40.51	$3.95	$0.01	$0.16	$4.12	10.9%	0.0%	0.4%	11.3%	30.1%
300	$34.72	$28.55	$2.64	$65.91	$39.12	$28.55	$2.82	$70.49	$4.40	$0.00	$0.18	$4.58	6.7%	0.0%	0.3%	6.9%	12.9%
400	$44.10	$38.06	$3.42	$85.58	$48.79	$38.07	$3.62	$90.48	$4.69	$0.01	$0.20	$4.90	5.5%	0.0%	0.2%	5.7%	11.6%
500	$53.48	$47.58	$4.21	$105.27	$58.46	$47.59	$4.42	$110.47	$4.98	$0.01	$0.21	$5.20	4.7%	0.0%	0.2%	4.9%	9.6%
600	$62.85	$57.09	$5.00	$124.94	$68.13	$57.11	$5.22	$130.46	$5.28	$0.02	$0.22	$5.52	4.2%	0.0%	0.2%	4.4%	7.7%
700	$72.23	$66.61	$5.79	$144.63	$77.80	$66.63	$6.02	$150.45	$5.57	$0.02	$0.23	$5.82	3.9%	0.0%	0.2%	4.0%	19.0%
1,200	$119.11	$114.18	$9.72	$243.01	$126.16	$114.22	$10.02	$250.40	$7.05	$0.04	$0.30	$7.39	2.9%	0.0%	0.1%	3.0%	6.8%
2,000	$194.13	$190.30	$16.02	$400.45	$203.54	$190.36	$16.41	$410.31	$9.41	$0.06	$0.39	$9.86	2.3%	0.0%	0.1%	2.5%	2.3%

		(1) Present Rates	(2) Proposed Rates
Customer Charge		$5.00	$8.50
RE Growth Factor		$0.78	$0.79
LIHEAP Charge		$0.81	$0.81
Transmission Energy Charge	kWh x	$0.03179	$0.03180
Base Distribution Energy Charge	kWh x	$0.03664	$0.04159
Other Distribution Energy Charges	kWh x	$0.00636	$0.00434
Transition Energy Charge	kWh x	$0.00057	$0.00057
Energy Efficiency Program Charge	kWh x	$0.01154	$0.01154
Renewable Energy Distribution Charge	kWh x	$0.00687	$0.00688
Gross Earnings Tax		4%	4%
Standard Offer Charge	kWh x	$0.09515	$0.09518

(1) Workpaper HSG-5 (REV-1), Page 1, Column (a)
(2) Workpaper HSG-5 (REV-1), Page 1, Column (b)

PUC 9-20

Request:

Using residential customer usage for the Test Year, how many A-60 customers would have higher bills, and how many would have lower bills at the end of the phase-in of customer charges if the proposed changes to the customers charges were in effect. Please break out the higher and lower results into at least five bins.

Response:

The requested information can be derived from Narragansett Electric's April 3, 2018 versions of Schedule HSG-5-B (REV-1), Schedule HSG-5-B1 (REV-1), and Schedule HSG-5-B2 (REV-1) for Years 1, 2, and 3 of the proposed phase-in, respectively. The schedules are provided in Attachment PUC 9-20, and relevant information is compiled below to present the increases and decreases in monthly bills based on current (November 2017) rates and Year 3 proposed rates.

Monthly kWh	% of Bills	Year 1 Increase (Decrease) over Present	Year 2 Increase (Decrease) over Year 2	Year 3 Increase (Decrease) over Year 2	Cumulative Increase (Decrease) over Present
150	32.1%	$0.16	$2.44	$2.65	$5.25
300	15.4%	($1.90)	$2.44	$2.66	$3.20
400	12.5%	($3.25)	$2.43	$2.65	$1.83
500	9.6%	($4.61)	$2.43	$2.66	$0.48
600	7.2%	($5.97)	$2.44	$2.66	($0.87)
700	16.4%	($7.33)	$2.44	$2.65	($2.24)
1,200	5.2%	($14.14)	$2.44	$2.66	($9.04)
2,000	1.6%	($25.02)	$2.42	$2.66	($19.94)

Prepared by or under the supervision of: Howard Gorman

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-B (REV-1)
Sheet 1 of 1

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed Rates
Rates Applicable to A-60 Rate Customers, Year 1

	Rates Effective November 1, 2017				Proposed Rates						Increase (Decrease)								
								Discounted			$				% of Total Bill				Percentage
Monthly kWh	Delivery	SOS	GET	Total	Delivery	SOS	Discount	Total	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	of Customers
150	$13.64	$14.27	$1.16	$29.07	$18.73	$14.28	($4.95)	$28.06	$1.17	$29.23	$0.14	$0.01	$0.01	$0.16	0.5%	0.0%	0.0%	0.6%	32.1%
300	$25.68	$28.55	$2.26	$56.49	$33.11	$28.55	($9.25)	$52.41	$2.18	$54.59	($1.82)	$0.00	($0.08)	($1.90)	(3.2%)	-	(0.1%)	(3.4%)	15.4%
400	$33.71	$38.06	$2.99	$74.76	$42.69	$38.07	($12.11)	$68.65	$2.86	$71.51	($3.13)	$0.01	($0.13)	($3.25)	(4.2%)	0.0%	(0.2%)	(4.3%)	12.5%
500	$41.74	$47.58	$3.72	$93.04	$52.28	$47.59	($14.98)	$84.89	$3.54	$88.43	($4.44)	$0.01	($0.18)	($4.61)	(4.8%)	0.0%	(0.2%)	(5.0%)	9.6%
600	$49.77	$57.09	$4.45	$111.31	$61.87	$57.11	($17.85)	$101.13	$4.21	$105.34	($5.75)	$0.02	($0.24)	($5.97)	(5.2%)	0.0%	(0.2%)	(5.4%)	7.2%
700	$57.80	$66.61	$5.18	$129.59	$71.45	$66.63	($20.71)	$117.37	$4.89	$122.26	($7.06)	$0.02	($0.29)	($7.33)	(5.4%)	0.0%	(0.2%)	(5.7%)	16.4%
1,200	$97.95	$114.18	$8.84	$220.97	$119.38	$114.22	($35.04)	$198.56	$8.27	$206.83	($13.61)	$0.04	($0.57)	($14.14)	(6.2%)	0.0%	(0.3%)	(6.4%)	5.2%
2,000	$162.19	$190.30	$14.69	$367.18	$196.07	$190.36	($57.96)	$328.47	$13.69	$342.16	($24.08)	$0.06	($1.00)	($25.02)	(6.6%)	0.0%	(0.3%)	(6.8%)	1.6%

		(1) Present Rates	(2) Proposed Rates
Customer Charge		$0.00	$2.75
RE Growth Factor		$0.78	$0.79
LIHEAP Charge		$0.81	$0.81
Transmission Energy Charge	kWh x	$0.03179	$0.03180
Base Distribution Energy Charge	kWh x	$0.02317	$0.04159
Other Distribution Energy Charges	kWh x	$0.00636	$0.00348
Transition Energy Charge	kWh x	$0.00057	$0.00057
Energy Efficiency Program Charge	kWh x	$0.01154	$0.01154
Renewable Energy Distribution Charge	kWh x	$0.00687	$0.00688
Low Income Discount			$\boxed{15\%}$
Gross Earnings Tax		4%	4%
Standard Offer Charge	kWh x	$0.09515	$0.09518

(1) Workpaper HSG-5 (REV-1), Page 2, Column (a)
(2) Workpaper HSG-5 (REV-1), Page 2, Column (b)

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-B1 (REV-1)
Sheet 1 of 1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-B1 (REV-1)
Sheet 1 of 1

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed Rates
Rates Applicable to A-60 Rate Customers, Year 2

	Year 1 Proposed Rates						Year 2 Proposed Rates						Increase (Decrease)								
													$				% of Total Bill				
Monthly kWh	Delivery	SOS	Discount	Discounted Total	GET	Total	Delivery	SOS	Discount	Discounted Total	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	Percentage of Customers
150	$18.73	$14.28	($4.95)	$28.06	$1.17	$29.23	$21.48	$14.28	($5.36)	$30.40	$1.27	$31.67	$2.34	$0.00	$0.10	$2.44	8.0%	0.0%	0.3%	8.3%	32.1%
300	$33.11	$28.55	($9.25)	$52.41	$2.18	$54.59	$35.86	$28.55	($9.66)	$54.75	$2.28	$57.03	$2.34	$0.00	$0.10	$2.44	4.3%	0.0%	0.2%	4.5%	15.4%
400	$42.69	$38.07	($12.11)	$68.65	$2.86	$71.51	$45.44	$38.07	($12.53)	$70.98	$2.96	$73.94	$2.33	$0.00	$0.10	$2.43	3.3%	0.0%	0.1%	3.4%	12.5%
500	$52.28	$47.59	($14.98)	$84.89	$3.54	$88.43	$55.03	$47.59	($15.39)	$87.23	$3.63	$90.86	$2.34	$0.00	$0.09	$2.43	2.6%	0.0%	0.1%	2.7%	9.6%
600	$61.87	$57.11	($17.85)	$101.13	$4.21	$105.34	$64.62	$57.11	($18.26)	$103.47	$4.31	$107.78	$2.34	$0.00	$0.10	$2.44	2.2%	0.0%	0.1%	2.3%	7.2%
700	$71.45	$66.63	($20.71)	$117.37	$4.89	$122.26	$74.20	$66.63	($21.12)	$119.71	$4.99	$124.70	$2.34	$0.00	$0.10	$2.44	1.9%	0.0%	0.1%	2.0%	16.4%
1,200	$119.38	$114.22	($35.04)	$198.56	$8.27	$206.83	$122.13	$114.22	($35.45)	$200.90	$8.37	$209.27	$2.34	$0.00	$0.10	$2.44	1.1%	0.0%	0.0%	1.2%	5.2%
2,000	$196.07	$190.36	($57.96)	$328.47	$13.69	$342.16	$198.82	$190.36	($58.38)	$330.80	$13.78	$344.58	$2.33	$0.00	$0.09	$2.42	0.7%	0.0%	0.0%	0.7%	1.6%

		Year 1 Proposed Rates	Year 2 Proposed Rates	
Customer Charge		$2.75	$5.50	(1)
RE Growth Factor		$0.79	$0.79	
LIHEAP Charge		$0.81	$0.81	
Transmission Energy Charge	kWh x	$0.03180	$0.03180	
Base Distribution Energy Charge	kWh x	$0.04159	$0.04159	
Other Distribution Energy Charges	kWh x	$0.00348	$0.00348	
Transition Energy Charge	kWh x	$0.00057	$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154	$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00688	$0.00688	
Low Income Discount		15%	15%	
Gross Earnings Tax		4%	4%	
Standard Offer Charge	kWh x	$0.09518	$0.09518	

(1) Proposed Year 2 Customer Charge

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-B2 (REV-1)
Sheet 1 of 1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No.4770
Schedule HSG-5-B2 (REV-1)
Sheet 1 of 1

The Narragansett Electric Company
Calculation of Monthly Typical Bill
Total Bill Impact of Proposed Rates
Rates Applicable to A-60 Rate Customers, Year 3

	Year 2 Proposed Rates						Year 3 Proposed Rates						Increase (Decrease)								
				Discounted						Discounted			$				% of Total Bill				Percentage
Monthly kWh	Delivery	SOS	Discount	Total	GET	Total	Delivery	SOS	Discount	Total	GET	Total	Delivery	SOS	GET	Total	Delivery	SOS	GET	Total	of Customers
150	$21.48	$14.28	($5.36)	$30.40	$1.27	$31.67	$24.48	$14.28	($5.81)	$32.95	$1.37	$34.32	$2.55	$0.00	$0.10	$2.65	8.1%	0.0%	0.3%	8.4%	32.1%
300	$35.86	$28.55	($9.66)	$54.75	$2.28	$57.03	$38.86	$28.55	($10.11)	$57.30	$2.39	$59.69	$2.55	$0.00	$0.11	$2.66	4.5%	0.0%	0.2%	4.7%	15.4%
400	$45.44	$38.07	($12.53)	$70.98	$2.96	$73.94	$48.44	$38.07	($12.98)	$73.53	$3.06	$76.59	$2.55	$0.00	$0.10	$2.65	3.4%	0.0%	0.1%	3.6%	12.5%
500	$55.03	$47.59	($15.39)	$87.23	$3.63	$90.86	$58.03	$47.59	($15.84)	$89.78	$3.74	$93.52	$2.55	$0.00	$0.11	$2.66	2.8%	0.0%	0.1%	2.9%	9.6%
600	$64.62	$57.11	($18.26)	$103.47	$4.31	$107.78	$67.62	$57.11	($18.71)	$106.02	$4.42	$110.44	$2.55	$0.00	$0.11	$2.66	2.4%	0.0%	0.1%	2.5%	7.2%
700	$74.20	$66.63	($21.12)	$119.71	$4.99	$124.70	$77.20	$66.63	($21.57)	$122.26	$5.09	$127.35	$2.55	$0.00	$0.10	$2.65	2.0%	0.0%	0.1%	2.1%	16.4%
1,200	$122.13	$114.22	($35.45)	$200.90	$8.37	$209.27	$125.13	$114.22	($35.90)	$203.45	$8.48	$211.93	$2.55	$0.00	$0.11	$2.66	1.2%	0.0%	0.1%	1.3%	5.2%
2,000	$198.82	$190.36	($58.38)	$330.80	$13.78	$344.58	$201.82	$190.36	($58.83)	$333.35	$13.89	$347.24	$2.55	$0.00	$0.11	$2.66	0.7%	0.0%	0.0%	0.8%	1.6%

		Year 2 Proposed Rates	Year 3 Proposed Rates	
Customer Charge		$5.50	$8.50	(1)
RE Growth Factor		$0.79	$0.79	
LIHEAP Charge		$0.81	$0.81	
Transmission Energy Charge	kWh x	$0.03180	$0.03180	
Base Distribution Energy Charge	kWh x	$0.04159	$0.04159	
Other Distribution Energy Charges	kWh x	$0.00348	$0.00348	
Transition Energy Charge	kWh x	$0.00057	$0.00057	
Energy Efficiency Program Charge	kWh x	$0.01154	$0.01154	
Renewable Energy Distribution Charge	kWh x	$0.00688	$0.00688	
Low Income Discount		15%	15%	
Gross Earnings Tax		4%	4%	
Standard Offer Charge	kWh x	$0.09518	$0.09518	

(1) Proposed Year 3 Customer Charge

PUC 9-21

Request:

How many non-firm customers on the rate as of July 2009, are still non-firm customers? How often were those customers interrupted in each of the past three years?

Response:

As of July 2009, there were 27 non-firm customers. There are currently only 11 non-firm customers remaining.

Non-firm customers were interrupted 14 times, for a total of 48 days, over the past three fiscal years (i.e., 12 months ending March 31, 2016 through March 31, 2018). Below are the dates Narragansett Gas called for interruption:

1	January 4, 2016 - January 6, 2016
2	January 13, 2016 - January 14, 2016
3	January 18, 2016 - January 23, 2016
4	February 11, 2016 - February 16, 2016
5	December 15, 2016 - December 17, 2016
6	January 6, 2017 - January 10, 2017
7	February 2, 2017 - February 5, 2017
8	February 9, 2017 - February 11, 2017
9	February 16, 2017 - February 17, 2017
10	March 4, 2017 - March 5, 2017
11	March 10, 2017 - March 13, 2017
12	March 15, 2017 - March 18, 2017
12	December 13, 2017 - December 15, 2017
13	December 27, 2017 - January 8, 2018
14	January 14, 2018 - January 16, 2018

Prepared by or under the supervision of: Ann Leary

PUC 9-22

Request:

Has the Company performed any analysis of the benefits of encouraging non-firm gas supply service compared to buying more gas supply? If so, please provide. If not, why not?

Response:

By way of background, for a customer to be on a non-firm rate classification, the customer must maintain adequate standby facilities for the use of an alternate fuel that may be substituted for gas when gas transportation is not available. The non-firm customer must be able to switch to their alternate fuel supply within a day's notice. In addition, any customer interested in non-firm service must purchase their gas supply from a third-party marketer and not Narragansett Gas because Narragansett Gas' Non-Firm Sales Tariff (Rate 60) has not been available to new customers since July 1, 2009. Only Non-Firm Transportation Service (Rate 61) is available to customers.

As indicated in Narragansett Gas' response to PUC 9-21, Narragansett Gas has called for non-firm customers to curtail their gas requirements for 48 days in the past three years. These service interruptions occur on the coldest days of the year.

Encouraging customers to move to a non-firm rate and curtailing their gas usage on cold days will not have significant impact on reducing gas supply costs. First, only customers with dual fuel capability can convert to non-firm service because of the tariff requirement that non-firm customers have an alternate fuel supply. Based on this requirement, Narragansett Gas performed a review and analysis to determine an estimate of the maximum potential reduction in gas cost purchases if all of its firm sales dual fuel customers were on non-firm service, thereby subjecting them to curtailments called by Narragansett Gas.

Narragansett Gas believes that there are currently less than 30 firm customers[1] with dual fuel capability, and only 11 of these dual fuel customers are firm sales customers that receive their gas supply from Narragansett Gas. These 11 customers are those that could become non-firm transportation customers. These 11 customers account for less than 0.6 percent of Narragansett Gas' annual gas purchases. To estimate the maximum potential savings Narragansett Gas could realize if the 11 customers had been subject to curtailment, Narragansett Gas based its analysis on actual gas prices during January 2018.[2] Narragansett Gas' analysis indicates that its January

[1] Narragansett Gas has not maintained a list of firm customers with dual fuel capability. Therefore, Narragansett Gas used a list from its 2011-12 On-System Margin reconciliation contained in its Distribution Adjustment Charge (DAC) factor.

[2] January 2018 contained significant increases in gas prices due to increased demand resulting from colder than normal weather.

Prepared by or under the supervision of: Ann Leary

2018 gas costs may have been reduced by $875,000[3] if the 11 dual fuel sales customers were subject to curtailment, and all of their gas usage was reduced accordingly. This equates to annual gas cost savings of 0.4 percent. Although gas cost savings associated with these 11 customers may be possible, the estimated maximum potential savings of $875,000 is not a significant amount that justifies the time and effort needed to encourage firm sales dual fuel customers to convert to non-firm service. Also, there are many reasons why customers prefer firm service instead of interruptible service. Because these customers have dual fuel capability and could have requested non-firm service at any time, one can conclude that they prefer the benefits associated with firm, uninterrupted service. Finally, because these 11 customers are on firm service, Narragansett Gas is not aware of whether they have maintained their alternate fuel supply and associated equipment as a viable option.

[3] Calculated as the January 2018 gas usage for the 11 dual fuel sales customers of approximately 35,000 Dktherms multiplied by a price of $25/Dktherm.

PUC 9-23

Request:

Have any G-62 customers engaged in any net metering projects? If so, please identify. If the response is in the affirmative, has the please explain how combining the G-32 and G-62 rate classes would affect the credits or value of the credits to the current G-62 customers.

Response:

There is currently one Rate G-62 customer that is net metering. This account has not been generating electricity in excess of its on-site usage. Therefore, combining the Rate G-32 and Rate G-62 rate classes will have no impact on the renewable generation credits the Rate G-62 net metering customer has been receiving because the customer is not exporting any of its generation in excess of on-site usage.

Prepared by or under the supervision of: Scott McCabe

PUC 9-24

Request:

Regarding National Grid's response to Navy/FEA 1-2 in Docket No. 4780, please confirm that it is National Grid's opinion that none of the programs proposed in Docket 4780 will have an effect on distributed generation programs, or if something else was intended with this answer.

Response:

The Company confirms that none of the programs proposed in Docket No. 4780 will have an effect on current distributed generation programs.

Prepared by or under the supervision of: Timothy Roughan

PUC 9-25

Request:

Niagara Mohawk agreed to a metric designed to provide an incentive for the Company to reduce the number of residential service terminations for non-payment while decreasing, or maintaining, the level of bad debt from residential accounts based on a five-year average.

a. Please explain the mechanisms available in New York which would enable the Company to meet the metric.

b. Are those mechanisms available in Rhode Island?

c. What are the differences in New York regulations and Rhode Island regulations that would affect (positively or negatively) the ability of Narragansett Electric or Narragansett Gas to work toward meeting such a metric?

Response:

a. The Joint Proposal[1] in the Niagara Mohawk rate case (Cases 17-E-0238 and 17G-0239), the terms of which were adopted by the New York Public Service Commission in its *Order Adopting the Terms of Joint Proposal and Establishing Electric and Gas Rate Plans* (issued and effective March 15, 2018), includes a Termination and Uncollectible Expense metric and incentive. The metric is designed to provide an incentive for Niagara Mohawk to reduce the number of residential service terminations for non-payment while decreasing, or maintaining, the level of bad debt from residential accounts. The metric measures the number of annual residential terminations and the total annual uncollectible expense (i.e., write offs) for the combined electric and gas segments.

   Niagara Mohawk has the ability to manage the volume of service terminations by controlling the number of termination orders that are issued to the field. The degree to which controlled dispatching will control termination volumes adequately depends on the volatility of the effectiveness of the field. In recent years, the field effectiveness rate has been stable.

   Niagara Mohawk has less ability to influence the second component of the metric, which captures the level of bad debt from residential accounts. Bad debt results when an account closes with outstanding arrears. It is strongly influenced by fluctuations in

[1] On January 19, 2018, Niagara Mohawk Power Corporation (Niagara Mohawk), the New York Department of Public Service Staff, and the other parties in the case entered into a Joint Proposal that memorializes the settlement agreement among the parties.

commodity prices, weather, economic health, and consumer behavior. When terminations are limited by Niagara Mohawk, one should expect a modest immediate corresponding drop in write-off rates. This is because bad debt write-off occurs after an account is closed (whether voluntarily or as a result of service termination). In the long term, however, reduced termination rates would be expected to lead to a rise in bad debt. This is because lower terminations ultimately lead to higher account balances. Thus, a temporary drop in bad debt write-off is likely to be followed by a long term rise in bad debt above current levels.

b. The mechanisms described in the response to part a. above would operate similarly in Rhode Island.

c. The regulatory differences between New York and Rhode Island would not be expected to have a large effect on the mechanisms described above, or on the ability of Narragansett Electric or Narragansett Gas to work toward meeting such a metric. That said, for Rhode Island, the Company suggests that development of a performance incentive focused on outcomes for income eligible customers be evaluated following implementation of the Company's proposals affecting income eligible customers.

(This response is identical to the Company's response to PUC 1-1 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 9-26

Request:

Please complete the following table for the years 2012-2017, where the example below is the for year 2012 only, and provide the data in a machine-readable file. Further:

a. please be sure to indicate where National Grid believes the entries are not applicable, unknown, or zero;

b. for all monetary values, please use nominal dollars;

c. for each year requested, please use the program year that overlapped the most with the calendar year, and indicate which program years were used in the response (e.g., for year 2018, use ISR FY2017;

d. for "company earnings" related to incentives, please use the (nominal dollar) value National Grid collected for the program year achievement, whether it was concurrent with or after the program year; and

e. for "company earnings" related to capital investment, please use the (nominal dollar) value of earnings included in the revenue requirement that was calculated after any applicable annual reconciliations.

Response:

Please see Attachment PUC 9-26-1, which provides the information requested in the table below, and Attachment PUC 9-26-2, which provides supporting calculations for the estimated earnings from VVO/CVR. With respect to the Infrastructure, Safety, and Reliability (ISR) Plan, the Company interpreted this question as seeking earnings and impact information for the Company's VVO/CVR Pilot and Expansion programs under the Company's ISR Plan, rather than the ISR Plan overall.

(This response is identical to the Company's response to PUC 1-2 in Docket No. 4780.)

2012											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	119,666,157	N/A	19,947	N/A	56,243	201,351	119,666,157	0	$ 49,869,528	$ 2,469,411
System Reliability Procurement	N/A	132,000	N/A	N/A	42	N/A	107	224600	0	$ 133,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$0	$ -	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Long-term Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 581,777	$ -
DG Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -
Net Metering	6	N/A	N/A	N/A	N/A	N/A	61	N/A	N/A	$ 329,386	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 12,803,595	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
Program costs for Long-term Contracts represents administrative costs associated with PPA negotiation
For Net Metering and ReGrowth, number of kW and participants provided based on date authroity to interconnect was given i.e. CY2012
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth

2013											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	157,121,309	N/A	26,427	N/A	73847.02	493,271	157,121,309		$ 63,145,737	$ 2,997,681
System Reliability Procurement	N/A	790,000	N/A	N/A	266	N/A	321	653000		$ 672,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 139
FY 14									$56,889	$ -	$ 139
FY 13									-	-	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Long-term Contracts	36	81,666,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,204,145	$ 146,297
DG Contracts	11	4,490,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 416,028	$ 20,238
Net Metering	1	N/A	N/A	N/A	N/A	N/A	60	N/A	N/A	$ 51,554	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 18,964,816	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2013

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

2014												
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	268,468,226	N/A	38,693	N/A	126,180	551,882	268,468,226	N/A	$ 85,348,093	$ 4,223,321
System Reliability Procurement	N/A	455,000	N/A	N/A	120	N/A	197	464,000	N/A	$ 569,300	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 14,522
FY 15									$ 2,014,587	$ -	$ 13,947
FY 14									-	$ -	$ 574
FY 13									-	-	$ -
Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 77,121	$ -
Long-term Contracts	36	234,392,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,642,891	$ 757,319
DG Contracts	16	18,108,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,649,080	$ 119,283
Net Metering	1	N/A	N/A	N/A	N/A	N/A	88	N/A	N/A	$ 125,526	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 17,899,440	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2014
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth

2015												
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	222,822,045	N/A	33335.385	N/A	104726.4	622822.4271	222822044.5	N/A	$ 87,430,831	$ 4,533,360
System Reliability Procurement	N/A	685,000	N/A	N/A	144	N/A	267	251700	N/A	$ 1,029,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 45,848
FY 16									$ 2,212,462	$ -	$ 18,761
FY 15									-	-	$ 26,612
FY 14									-	-	$ 475
FY 13									-	-	$ -
Renewable Energy Growth	3	N/A	N/A	N/A	N/A	N/A	438	N/A	N/A	$ 675,133	$ 103
Long-term Contracts	36	238,276,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 7,150,901	$ 792,715
DG Contracts	19	22,784,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 3,516,629	$ 141,560
Net Metering	3	N/A	N/A	N/A	N/A	N/A	330	N/A	N/A	$ 551,915	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 13,958,024	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2015

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

2016											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	214,328,549	N/A	30,530	N/A	100734.4	758,284	214,328,549	N/A	$ 78,402,087	$ 4,128,034
System Reliability Procurement	N/A	550,000	N/A	N/A	96	N/A	155	(158,500)	N/A	$ 989,700	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 70,175
FY 17									$ 1,573,303	$ -	$ 9,353
FY 16											$ 36,364
FY 15											$ 24,080
FY 14											$ 377
FY 13											$ -
Renewable Energy Growth	12	N/A	N/A	N/A	N/A	N/A	906	N/A	N/A	$ 1,797,768	$ 16,843
Long-term Contracts	66	235,107,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 14,654,577	$ 812,217
DG Contracts	23	26,695,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,228,911	$ 168,717
Net Metering	13	N/A	N/A	N/A	N/A	N/A	677	N/A	N/A	$ 1,713,779	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 8,968,717	N/A

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2016

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

The annual impacts of VVO/CVR are not available. During 2016, the pilot was in M&V and undergoing commissioning efforts, resulting in many "off" days.

2017											
	Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)
Energy Efficiency	N/A	232,023,450	N/A	29,363	N/A	109,051	687,141	232,023,450		$ 94,841,567	$ 4,829,847
System Reliability Procurement	N/A	718,000	N/A	N/A	352	N/A	120	63,000		$ 1,349,400	$ -
ISR -- VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 86,750
FY 18									$ 1,393,536	$ 60,000	$ 12,970
FY 17									-	-	$ 17,786
FY 16									-	-	$ 34,142
FY 15									-	-	$ 21,579
FY 14									-	-	$ 274
FY 13									-	-	$ -
Renewable Energy Growth	13	N/A	N/A	N/A	N/A	N/A	922	N/A		$ 7,040,636	$ 120,473
Long-term Contracts	69	332,488,731	N/A	N/A	N/A	N/A	N/A	N/A		$ 37,154,188	$ 1,480,355
DG Contracts	23	27,979,500	N/A	N/A	N/A	N/A	N/A	N/A		$ 4,890,691	$ 171,131
Net Metering	13	N/A	N/A	N/A	N/A	N/A	512	N/A		$ 3,149,512	N/A
Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A		$ 3,753,535	N/A

Notes:
CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2017
Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
The Company does not have estimates of generation from net metering and REGrowth
ReGrowth program costs and earnings are preliminary and have not yet been filed
Renewable Energy Standard obligation year is not yet complete.
2017 kWh values for Long-term and DG Contracts are estimates
The annual impacts of VVO/CVR are not available. During 2017, the Pilot was being extensivly debugged for communications issues, resulting in significant off-time.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1									2012								
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 13									$0	($7,819,012)	$0	0.00%	($2,520,717)	9.50%	($117,675)	$0
5	Total ISR Earnings															($117,675)	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2013															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 14									$0	$12,842,359	$56,889	0.44%	$670,654	9.50%	$31,308	$139
5	FY 13												0.00%	($4,847,343)	9.50%	($226,289)	$0
6	Total ISR Earnings															($194,980)	
7																	
8																	
9																	
10																	
11																	
12																	
13																	
14																	
15																	
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27																	
28																	
29																	
30																	
31																	
32																	
33										0.44%							

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2014															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 15									$0	$76,340,403	$2,014,587	2.64%	$11,321,526	9.50%	$528,523	$13,947
5	FY 14												0.44%	$2,776,084	9.50%	$129,596	$574
6	FY 13												0.00%	($4,462,400)	9.50%	($208,318)	$0
7	Total ISR Earnings															$449,801	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2015															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 16									$0	$72,003,445	$2,212,462	3.07%	$13,079,273	9.50%	$610,580	$18,761
5	FY 15												2.64%	$21,601,446	9.50%	$1,008,420	$26,612
6	FY 14												0.44%	$2,296,849	9.50%	$107,224	$475
7	FY 13												0.00%	($4,083,689)	9.50%	($190,639)	$0
8	Total ISR Earnings															$1,535,585	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1		2016															
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 17									$0	$75,489,338	$1,573,303	2.08%	$9,613,558	9.50%	$448,790	$9,353
5	FY 16												3.07%	$25,350,698	9.50%	$1,183,447	$36,364
6	FY 15												2.64%	$19,546,098	9.50%	$912,470	$24,080
7	FY 14												0.44%	$1,825,365	9.50%	$85,214	$377
8	FY 13												0.00%	($3,710,743)	9.50%	($173,229)	$0
9	Total ISR Earnings															$2,456,692	

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1									2017								
2		Nameplate Capacity (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	VVO/CVR O&M	Total ISR Capital Investment	VVO/CVR Cap	VVO/CVR % to Total Capital	Average Rate Base	Allowed ROE	Company Earnings After-tax	VVO/CVR Proportionate Share of Earnings
3	Infrastructure Safety, Reliability (e.g., VVO/CVR)																
4	FY 18									$60,000	$74,843,000	$1,393,536	1.86%	$14,921,086	9.50%	$696,561	$12,970
5	FY 17												2.08%	$18,280,458	9.50%	$853,387	$17,786
6	FY 16												3.07%	$23,801,658	9.50%	$1,111,133	$34,142
7	FY 15												2.64%	$17,516,401	9.50%	$817,718	$21,579
8	FY 14												0.44%	$1,323,312	9.50%	$61,776	$274
9	FY 13												0.00%	($3,311,205)	9.50%	($154,577)	$0
10	Total ISR Earnings															$3,385,998	

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4				VVO/CVR Pilot			VVO/CVR Expansion						
5				C053111	C046352	C052708	C075571	C075573	C077200	C076365	C077201	C076367	**TOTAL**
6			FY13										
7			FY14	$33,706	$18,926	$4,258							**$56,889**
8			FY15	$362,894	$1,490,001	$161,692							**$2,014,587**
9			FY16	$615,566	$1,540,206	$56,690							**$2,212,462**
10			FY17	$244,830	$1,319,335	$9,138	$0	$0	$0	$0	$0	$0	**$1,573,303**
11			FY18	$54,019	$298,732	$19	$214.20	$40,055	$182,509	$57,501	$498,398	$262,089	**$1,393,536**

PUC 9-27

Request:

For each year in the response to 9-26, please provide the following:

a. The minimum, maximum, and average Program Cost for each Outcome Category for that year;

b. The minimum, maximum, and average Company Earnings for each Outcome Category for that year.

Response:

Please see Attachment PUC 9-27, which provides the information requested for relevant outcomes for each year. The Company's response to part a. is addressed in the table beginning at Column A, Row 23. The Company's response to part b. is addressed in the table beginning at Column H, Row 23. Please note that, when an incentive is calculated over multiple outcomes as suggested in part b. of the question, the value of that incentive for an individual outcome will be overstated.

(This response is identical to the Company's response to PUC 1-3 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5							2012						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	119,666,157	N/A	19,947	N/A	56,243	201,351	119,666,157	$ -	$ 49,869,528	$ 2,469,411	
8	System Reliability Procurement	N/A	132,000	N/A	N/A	42	N/A	107	224600	$ -	$ 133,400	$ -	
9	VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -	$ -	
10	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Long-term Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 581,777	$ -	
12	DG Contracts	0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ -	$ -	
13	Net Metering	6	N/A	N/A	N/A	N/A	N/A	61	N/A	N/A	$ 329,386	N/A	
14	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 12,803,595	N/A	
15													
16		Notes:											
17		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
18		Program costs for Long-term Contracts represents administrative costs associated with PPA negotiation											
19		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2012											
20		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
21		The Company does not have estimates of generation from net metering and REGrowth											
22													
23		**Program cost per unit of outcome**							**Incentive cost per unit of outcome**				
24		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
25	Minimum	$ 53,576	$ 0.42	$ 2,500	$ 3,176	$ 887		Minimum	N/A	$ 0.02	N/A	N/A	N/A
26	Average (weighted)	$ 53,576	$ 0.42	$ 2,500	$ 3,176	$ 887		Average (weight	N/A	$ 0.02	N/A	N/A	N/A
27	Maximum	$ 53,576	$ 1.01	$ 2,500	$ 3,176	$ 887		Maximum	N/A	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X	Y
1													
2													
3													
4													
5			Program cost per unit						Incentive cost per unit				
6		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2	
7	Energy Efficiency		$ 0	$ 2,500		$ 887			$ 0.02	N/A	N/A	N/A	
8	System Reliability Procurement		$ 1		$ 3,176				$ -		$ -		
9	VVO/CVR												
10	Renewable Energy Growth												
11	Long-term Contracts												
12	DG Contracts												
13	Net Metering	$ 53,576											
14	Renewable Energy Standard												
15													
16													
17													
18													
19													
20													
21													
22													
23													
24													
25	Minimum												
26	Average (weighted)												
27	Maximum												

	A	B	C	D	E	F	G	H	I	J	K	L	M
1							2013						
2		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
3	Energy Efficiency	N/A	157,121,309	N/A	26,427	N/A	73847.0154	493,271	157,121,309		$ 63,145,737	$ 2,997,681	
4	System Reliability Procurement	N/A	790,000	N/A	N/A	266	N/A	321	653000		$ 672,400	$ -	
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 139	
6	FY 14									$56,889	$ -	$ 139	
7	FY 13									-	-	$ -	
8													
9	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
10	Long-term Contracts	36	81,666,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,204,145	$ 146,297	
11	DG Contracts	11	4,490,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 416,028	$ 20,238	
12	Net Metering	1	N/A	N/A	N/A	N/A	N/A	60	N/A	N/A	$ 51,554	N/A	
13	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 18,964,816	N/A	
14													
15		Notes:											
16		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
17		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2013											
18		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
19		The Company does not have estimates of generation from net metering and REGrowth											
20													
21		**Program cost per unit of outcome**							**Incentive cost per unit of outcome**				
22		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
23	Minimum	$ 37,228	$ 0.03	$ 2,389	$ 2,528	$ 855		Minimum	$ 1,811.03	$ 0.00	N/A	N/A	N/A
24	Average (weighted)	$ 55,176	$ 0.27	$ 2,389	$ 2,528	$ 855		Average (weighted	$ 3,525.82	$ 0.01	N/A	N/A	N/A
25	Maximum	$ 61,128	$ 0.85	$ 2,389	$ 2,528	$ 855		Maximum	$ 4,057.27	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1			Program cost per unit						Incentive cost per unit			
2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
3	Energy Efficiency		$ 0.40	$ 2,389.47		$ 855.09			$ 0.02	N/A	N/A	N/A
4	System Reliability Procurement		$ 0.85		$ 2,527.82							
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
6	FY 14											
7	FY 13											
8												
9	Renewable Energy Growth											
10	Long-term Contracts	$ 61,127.77	$ 0.03					$ 4,057.27	$ 0.00			
11	DG Contracts	$ 37,228.44	$ 0.09					$ 1,811.03	$ 0.00			
12	Net Metering	$ 43,359.13										
13	Renewable Energy Standard											
14												
15												
16												
17												
18												
19												
20												
21												
22												
23	Minimum											
24	Average (weighted)											
25	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
1		2014											
2		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
3	Energy Efficiency	N/A	268,468,226	N/A	38,693	N/A	126,180	551,882	268,468,226	N/A	$ 85,348,093	$ 4,223,321	
4	System Reliability Procurement	N/A	455,000	N/A	N/A	120	N/A	197	464,000	N/A	$ 569,300	$ -	
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 14,522	
6	FY 15									$ 2,014,587	$ -	$ 13,947	
7	FY 14									-	-	$ 574	
8	FY 13									-	-	$ -	
9													
10	Renewable Energy Growth	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 77,121	$ -	
11	Long-term Contracts	36	234,392,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,642,891	$ 757,319	
12	DG Contracts	16	18,108,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 2,649,080	$ 119,283	
13	Net Metering	1	N/A	N/A	N/A	N/A	N/A	88	N/A	N/A	$ 125,526	N/A	
14	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 17,899,440	N/A	
15													
16		Notes:											
17		CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"											
18		For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2014											
19		Nameplate capacity for Long-term Contracts and DG Contracts is cumulative											
20		The Company does not have estimates of generation from net metering and REGrowth											
21													
22		**Program cost per unit of outcome**							**Incentive cost per unit of outcome**				
23		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
24	Minimum	$ 128,762	$ 0.02	$ 2,206	$ 4,744	$ 676		Minimum	$ 7,334.14	$ 0.00	N/A	N/A	N/A
25	Average (weighted)	$ 140,016	$ 0.12	$ 2,206	$ 4,744	$ 676		Average (weighte	$ 16,753.98	$ 0.01	N/A	N/A	N/A
26	Maximum	$ 191,936	$ 1.25	$ 2,206	$ 4,744	$ 676		Maximum	$ 21,002.81	$ 0.02	N/A	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1			Program cost per unit					Incentive cost per unit				
2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
3	Energy Efficiency		$ 0.32	$ 2,205.79		$ 676.40			$ 0.02	N/A	N/A	N/A
4	System Reliability Procurement		$ 1.25		$ 4,744.17							
5	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
6	FY 15											
7	FY 14											
8	FY 13											
9												
10	Renewable Energy Growth											
11	Long-term Contracts	$ 128,761.73	$ 0.02					$ 21,002.81	$ 0.00			
12	DG Contracts	$ 162,880.00	$ 0.15					$ 7,334.14	$ 0.01			
13	Net Metering	$ 191,935.78										
14	Renewable Energy Standard											
15												
16												
17												
18												
19												
20												
21												
22												
23												
24	Minimum											
25	Average (weighted)											
26	Maximum											

2015

	A	B	C	D	E	F	G	H	I	J	K	L	M
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	222,822,045	N/A	33335.385	N/A	104726.4	622,822.43	222,822,045	N/A	$ 87,430,831	$ 4,533,360	
8	System Reliability Procurement	N/A	685,000	N/A	N/A	144	N/A	267.00	251,700.00	N/A	$ 1,029,400	$ -	
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 45,848	
10	FY 16									$ 2,212,462	$ -	$ 18,761	
11	FY 15									-	-	$ 26,612	
12	FY 14									-	-	$ 475	
13	FY 13									-	-	$ -	
14													
15	Renewable Energy Growth	3	N/A	N/A	N/A	N/A	N/A	438	N/A	N/A	$ 675,133	$ 103	
16	Long-term Contracts	36	238,276,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 7,150,901	$ 792,715	
17	DG Contracts	19	22,784,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 3,516,629	$ 141,560	
18	Net Metering	3	N/A	N/A	N/A	N/A	N/A	330	N/A	N/A	$ 551,915	N/A	
19	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 13,958,024	N/A	

Notes:

CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2015

Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

The Company does not have estimates of generation from net metering and REGrowth

	A	B	C	D	E	F	G	H	I	J	K	L	M
27		Program cost per unit of outcome							Incentive cost per unit of outcome				
28		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
29	Minimum	$ 184,571	$ 0.03	$ 2,623	$ 7,149	$ 835		Minimum	$ 33.18	$ 0.00	$ 40.80	N/A	N/A
30	Average (weighted)	$ 195,355	$ 0.20	$ 2,623	$ 7,149	$ 835		Average (weigh	$ 16,050.45	$ 0.01	$ 40.80	N/A	N/A
31	Maximum	$ 217,504	$ 1.50	$ 2,623	$ 7,149	$ 835		Maximum	$ 21,984.43	$ 0.01	$ 40.80	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1												
2												
3												
4												
5			Program cost per unit					Incentive cost per unit				
6		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
7	Energy Efficiency		$ 0.39	$ 2,622.76		$ 834.85			$ 0.014	$ 40.80	N/A	N/A
8	System Reliability Procurement		$ 1.50		$ 7,148.61							
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
10	FY 16											
11	FY 15											
12	FY 14											
13	FY 13											
14												
15	Renewable Energy Growth	$ 217,504.19						$ 33.18				
16	Long-term Contracts	$ 198,316.63	$ 0.03					$ 21,984.43	$ 0.00			
17	DG Contracts	$ 184,570.88	$ 0.15					$ 7,429.78	$ 0.01			
18	Net Metering	$ 206,555.01										
19	Renewable Energy Standard											
20												
21												
22												
23												
24												
25												
26												
27												
28												
29	Minimum											
30	Average (weighted)											
31	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
5							2016						
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	214,328,549	N/A	30,530	N/A	100,734	758,284	214,328,549	N/A	$ 78,402,087	$ 4,128,034	
8	System Reliability Procurement	N/A	550,000	N/A	N/A	96	N/A	155	(158,500)	N/A	$ 989,700	$ -	
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 70,175	
10	FY 17									$1,573,303	$ -	$ 9,353	
11	FY 16											$ 36,364	
12	FY 15											$ 24,080	
13	FY 14											$ 377	
14	FY 13											$ -	
15													
16	Renewable Energy Growth	12	N/A	N/A	N/A	N/A	N/A	906	N/A	N/A	$ 1,797,768	$ 16,843	
17	Long-term Contracts	66	235,107,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 14,654,577	$ 812,217	
18	DG Contracts	23	26,695,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 4,228,911	$ 168,717	
19	Net Metering	13	N/A	N/A	N/A	N/A	N/A	677	N/A	N/A	$ 1,713,779	N/A	
20	Renewable Energy Standard	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$ 8,968,717	N/A	

22 Notes:
23 CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"
24 For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2016
25 Nameplate capacity for Long-term Contracts and DG Contracts is cumulative
26 The Company does not have estimates of generation from net metering and REGrowth
27 The annual impacts of VVO/CVR are not available. During 2016, the pilot was in M&V and undergoing commissioning efforts, resulting in many "off" days.

	A	B	C	D	E	F	G	H	I	J	K	L	M
29		Program cost per unit of outcome							Incentive cost per unit of outcome				
30		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2			Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
31	Minimum	$ 128,123	$ 0.06	$ 2,568	$ 10,309	$ 778		Minimum	$ 1,437	$ 0.00	$ 40.56	N/A	N/A
32	Average (weighted)	$ 196,536	$ 0.21	$ 2,568	$ 10,309	$ 778		Average (weighted	$ 9,921	$ 0.01	$ 40.56	N/A	N/A
33	Maximum	$ 221,844	$ 1.80	$ 2,568	$ 10,309	$ 778		Maximum	$ 12,296	$ 0.01	$ 40.56	N/A	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X
1												
2												
3												
4												
5			Program cost per unit						Incentive cost per unit			
6		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
7	Energy Efficiency		$ 0.37	$ 2,568.00		$ 778.30			$ 0.01	$ 40.56	N/A	N/A
8	System Reliability Procurement		$ 1.80		$ 10,309.38							
9	Infrastructure Safety, Reliability (e.g., VVO/CVR)											
10	FY 17											
11	FY 16											
12	FY 15											
13	FY 14											
14	FY 13											
15												
16	Renewable Energy Growth	$ 153,393.14						$ 1,437.12				
17	Long-term Contracts	$ 221,844.09	$ 0.06					$ 12,295.51	$ 0.00			
18	DG Contracts	$ 185,519.25	$ 0.16					$ 7,401.49	$ 0.01			
19	Net Metering	$ 128,123.43										
20	Renewable Energy Standard											
21												
22												
23												
24												
25												
26												
27												
28												
29												
30												
31	Minimum											
32	Average (weighted)											
33	Maximum											

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													
2													
3													
4													
5						2017							
6		Nameplate Capacity MW (Generation Only)	kWh Saved or Generated	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2	Participants	Net savings	Program Cost (Capital Investment)	Program Cost (O&M)	Company Earnings (Capital earnings are after-tax)	
7	Energy Efficiency	N/A	232023450.1	N/A	29363.339	N/A	109051.022	687141.1338	232023450.1		94841567.13	$ 4,829,847	
8	System Reliability Procurement	N/A	718000	N/A	N/A	352	N/A	120	63000		1349400	$ -	
9	VVO/CVR	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A			$ 86,750	
10	FY 18									$ 1,393,536	$60,000	$ 12,970	
11	FY 17									-	-	$ 17,786	
12	FY 16									-	-	$ 34,142	
13	FY 15									-	-	$ 21,579	
14	FY 14									-	-	$ 274	
15	FY 13									-	-	$ -	
16													
17	Renewable Energy Growth	13	N/A	N/A	N/A	N/A	N/A	922	N/A		$7,040,636	$ 120,473	
18	Long-term Contracts	69	332,488,731	N/A	N/A	N/A	N/A	N/A	N/A		$37,154,188	$ 1,480,355	
19	DG Contracts	23	27,979,500	N/A	N/A	N/A	N/A	N/A	N/A		$4,890,691	$ 171,131	
20	Net Metering	13	N/A					512			$3,149,512	N/A	
21	Renewable Energy Standard	N/A	N/A	N/A							$3,753,535	N/A	

22

23 Notes:

24 CO2 impacts from Energy Efficiency are estimated assuming a grid emissions rate of 0.47 short tons/MWh, based on ISO-NE 2014 "Electric Generator Air Emissions Report"

25 For Net Metering and ReGrowth, number of kW and Participants provided based on date authroity to interconnect was given i.e. CY2017

26 Nameplate capacity for Long-term Contracts and DG Contracts is cumulative

27 The Company does not have estimates of generation from net metering and REGrowth

28 ReGrowth program costs and earnings are preliminary and have not yet been filed

29 Renewable Energy Standard obligation year is not yet complete.

30 2017 kWh values for Long-term and DG Contracts are estimates

31 The annual impacts of VVO/CVR are not available. During 2017, the Pilot was being extensivly debugged for communications issues, resulting in significant off-time.

32

	A	B	C	D	E	F
33		**Program cost per unit of outcome**				
34		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2
35	Minimum	$ 214,551	$ 0.11	$ 3,230	$ 3,834	$ 870
36	Average (weighted)	$ 440,902	$ 0.23	$ 3,230	$ 3,834	$ 870
37	Maximum	$ 537,494	$ 1.88	$ 3,230	$ 3,834	$ 870

	H	I	J	K	L
33		**Incentive cost per unit of outcome**			
34		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW
35	Minimum	$ 7,507	$ 0.00	$ 49.35	N/A
36	Average (weight	$ 16,851	$ 0.01	$ 49.35	N/A
37	Maximum	$ 21,374	$ 0.01	$ 49.35	N/A

	A	N	O	P	Q	R	S	T	U	V	W	X	Y
1													
2													
3													
4													
5			Program cost per unit						Incentive cost per unit				
6		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2		Capacity (MW)	kWh Saved or Generated	Avoided Bulk kW	Avoided Dist kW	Avoided CO2	
7	Energy Efficiency		$ 0.41	$ 3,229.93		$ 869.70			$ 0.01	$ 49.35	N/A	N/A	
8	System Reliability Procurement		$ 1.88		$ 3,833.52								
9	VVO/CVR												
10	FY 18												
11	FY 17												
12	FY 16												
13	FY 15												
14	FY 14												
15	FY 13												
16													
17	Renewable Energy Growth	$ 537,494.16						$ 9,197.13					
18	Long-term Contracts	$ 536,460.59	$ 0.11					$ 21,374.49	$ 0.00				
19	DG Contracts	$ 214,551.05	$ 0.17					$ 7,507.38	$ 0.01				
20	Net Metering	$ 236,432.10											
21	Renewable Energy Standard												
22													
23													
24													
25													
26													
27													
28													
29													
30													
31													
32													
33													
34													
35	Minimum												
36	Average (weighted)												
37	Maximum												

PUC 9-28

Request:

Please complete the table above (in 9-26), but in this response provide information for all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section 3. For each program or subprogram, highlight (color or bold font) the metric National Grid has proposed and the metric for determining performance and related incentives. Please use the proposed target achievement and incentive for completing the table in this response.

Response:

The information requested is provided for all proposed programs and subprograms associated with a performance incentive in Attachment PUC 9-28. Note that the Company has modified Column B to include storage and has added Column J to account for outcomes/metrics not captured in the table from PUC 9-26.

(This response is identical to the Company's response to PUC 1-4 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

	A	B	C	D	E	F	G	H	I	J	K	L
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2019)	Company Earnings (Concurrent with Year 2019)
7	EV Off-Peak Rebate	N/A	300,000	N/A	90	N/A	22	***100***	N/A	N/A	$178,745.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	44	N/A	***188***	N/A	N/A	N/A	$408,640	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	557	N/A	N/A	***259***	$1,451,283	$93,794
12	Utility-Owned Storage	***3***	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$899,375	$46,897
13												
14	Notes:											
15	Metrics for incentive are indicated in bold and italics											
16	EV Off Peak Rebate -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1											
17	DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan											
18	The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table											
19	Electric Vehicles Program costs reflects only the portion of the Electric Vehicle Initiative related to vehicle conversion											
20	Company's proposed storage program impacts and costs are included; however, the program itself is not sufficient to achieve the target for Utility-owned Storage											
21	Company earnings reflect estimated performance incentive mechanism payment a the target level											
22												
23	The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11											

	A	B	C	D	E	F	G	H	I	J	K	L
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2020)	Company Earnings (Concurrent with Year 2020)
7	EV Off-Peak Rebate	N/A	750,000	N/A	220	N/A	62	***250***	N/A	N/A	$244,420.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	96	N/A	***279***	N/A	N/A	N/A	$1,032,390	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	757	N/A	N/A	***352***	$2,433,822	$93,794
12	Utility-Owned Storage	***3***	217,391	N/A	360	N/A	N/A	N/A	N/A	N/A	$1,365,563	$46,897

13
14 Notes:
15 Metrics for incentive are indicated in bold and italics
16 EV Off Peak Rebateand Utility-onwed Storage -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1
17 DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan
18 The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table
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22
23 The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11

	A	B	C	D	E	F	G	H	I	J	K	L
5												
6		Nameplate Capacity (MW Generation or Storage)	kWh Saved, Generated, or Shited off-peak	Avoided Transmission Peak kW	Avoided Bulk System kW	Avoided Distribution System kW	Avoided CO2 (short tons)	Participants	Net savings (kWh)	Incremental EV Adoption (above forecast)	Program Cost (FY or CY 2021)	Company Earnings (Concurrent with Year 2021)
7	EV Off-Peak Rebate	N/A	1,500,000	N/A	450	N/A	97	***500***	N/A	N/A	$332,567.00	$117,243
8	DR--Connected Solutions Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
9	DR-- C&I Participation	N/A	N/A	N/A	TBD	N/A	N/A	***TBD***	N/A	N/A	TBD	TBD
10	Electric Heat Initiative	N/A	N/A	N/A	154	N/A	***247***	N/A	N/A	N/A	$466,140	$38,925
11	Electric Vehicles	N/A	N/A	N/A	N/A	N/A	1026	N/A	N/A	***477***	$5,295,299	$93,794
12	Utility-Owned Storage	***3***	543,478	N/A	900	N/A	N/A	N/A	N/A	N/A	$41,250	$46,897

13
14 Notes:
15 Metrics for incentive are indicated in bold and italics
16 EV Off Peak Rebateand Utility-onwed Storage -- kWh value is estimated kWh shifted from peak to off-peak in Company submitted in response to Division 5-1
17 DR -- Connected Solutions and C& I Participation targets and incentives to be determined through Energy Efficiency 1-Year Plan
18 The Company's proposed Electric Heat Initiative targets were converted from metric to short tons for this table
19 Electric Vehicles Program costs reflects only the portion of the Electric Vehicle Initiative related to vehicle conversion
20 Company's proposed storage program impacts and costs are included; however, the program itself is not sufficient to achieve the target for Utility-owned Storage
21 Company earnings reflect estimated performance incentive mechanism payment a the target level
22
23 The Company's assumed value of a basis point for all 3 years is the estimated 2019 value of $46,897 submitted by the Company it its response to NECEC 1-11

PUC 9-29

Request:

For all programs and sub-programs proposed by National Grid in Docket 4780 that are associated with a performance incentive in Chapter 9, Section3, and that propose a range of achievement levels and associated incentives:

a. Provide the $/metric value for each proposed achievement level;

b. For any responses in part a that do not have a uniform $/metric value for all achievement levels, please provide a justification for the variation.

c. For any proposed $/metric value in part b that is above of the ranges identified in PUC 9-27.b for 2016 and 2017, please provide a justification for the value being above the range.

Response:

a. Please see Attachment PUC 9-29 for the requested information. Note that in preparing this response, the Company has corrected the minimum target for the EV Off-Peak Charging Rebate performance incentive mechanism for 2020.

b. For the Electric Heat Initiative, differences in the per-ton incentive value for the minimum and target levels reflect rounding in the number of basis points assigned. The maximum value was expanded to ensure that the incentive was large enough to motivate achievement of the stretch targets, given the relatively small number of basis points assigned to this incentive relative to other performance incentive mechanisms.

   For the Electric Vehicle Initiative, the per-vehicle value at the maximum level is slightly smaller than the minimum and target levels. This differential reflects modest rebalancing for the performance incentive mechanism portfolio at the maximum level, such as that described for the Electric Heat Initiative above, to ensure that each incentive had a sufficiently meaningful maximum earning opportunity.

   For Company-owned storage, the slight difference between the per-MW incentive value at the minimum and target levels reflects rounding in the number of basis points assigned.

c. The Company does not currently earn incentives for any of the outcomes shown in Attachment PUC 9-29.

(This response is identical to the Company's response to PUC 1-5 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

Calculation of per unit incentive payments

Off-Peak Charging Rebate Pilot

						$/participant		
	2019	**2020**	**2021**	**Basis Points**	**Incentive Value**	**2019**	**2020**	**2021**
Min	80	200	400	2	$ 93,794	$ 1,172	$ 782	$ 469
Target	100	250	500	2.5	$ 117,243	$ 1,172	$ 782	$ 469
Maximum	120	300	600	3	$ 140,691	$ 1,172	$ 782	$ 469

Minimum Off-Peak Charging Rebate target for 2020 (in red) has been corrected

Electric Heat Initiatve						$/metric ton		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	137	202	179	0.670	$ 31,421	$ 229	$ 155	$ 175
Target	171	253	224	0.830	$ 38,925	$ 227	$ 154	$ 174
Maximum	206	303	269	2.000	$ 93,794	$ 456	$ 309	$ 349

Electric Vehicle Initiative						$/vehicle		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	130	176	239	1.00	$ 46,897	$ 362	$ 267	$ 197
Target	259	352	477	2.00	$ 93,794	$ 362	$ 267	$ 197
Maximum	518	703	954	3.50	$ 164,140	$ 317	$ 233	$ 172

Company-owned storage						$/MW		
	2019	2020	2021		Incentive Value	2019	2020	2021
Min	1	1	1	0.33	$ 15,476	$ 15,476	$ 15,476	$ 15,476
Target	3	3	3	1.00	$ 46,897	$ 15,632	$ 15,632	$ 15,632
Maximum	6	6	6	2.00	$ 93,794	$ 15,632	$ 15,632	$ 15,632

Assumed value
of a BPS $ 46,897

PUC 9-30

Request:

What is the Company's current expectation of the cost of RGGI allowances and Renewable Energy Certificates (RECs) over the next three years?

Response:

The current RGGI program runs through 2020. The RGGI states have proposed program changes that would apply to years 2021-2030. Modeling of the proposed program changes released by RGGI Inc. on September 18, 2017[1] projects an allowance price of $5.51/ton in 2017, $6.56/ton in 2020 (under existing program rules), and $7.81/ton in 2023 (under new program rules).[2] Linear interpolation of these results leads to the following allowance prices for 2019-2021, as shown below.

Projected RGGI Allowance Prices for 2019-2021 based on RGGI, Inc. Modeling (Nominal dollars)

Year	$ per/ton
2019	$6.21
2020	$6.56
2021	$6.98

The Avoided Energy Supply Costs in New England (AESC): 2015 Report[3] contained projections for Renewable Energy Credit (REC) prices. Projections for 2019-2021 are shown in the table below.

Projected REC prices based on AESC 2015 (Nominal dollars)

Year	$ per/MWh
2019	$46.24
2020	$44.79
2021	$54.93

(This response is identical to the Company's response to PUC 1-6 in Docket No. 4780.)

[1] RGGI, Inc. Draft IPM Base Model Rule Policy Case Results. September 18, 2017.
[2] The model does not produce results for each year. All prices are in nominal dollars.
[3] Hornby, R., et al. Avoided Energy Supply Costs in New England: 2015 Report. Prepared for the AESC 2015 Study Group. Revised April 3, 2015. See Exhibit F-1. An inflation rate of 2% is assumed to convert to nominal dollars.

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 9-31

Request:

How much CO2 does company expect is abated by purchase of a single RGGI allowance and REC?

Response:

By definition, purchase (and retirement) of a single RGGI allowance should imply 1 ton of CO_2 abatement. In practice, however, the potential for the RGGI cap to be non-binding, as well as the potential for emissions leakage outside of the RGGI states, means that actual abatement is uncertain.

With respect to RECs, the CO_2 grid emissions factor of 1029 lbs/MWh assumed in the Company's benefit-cost analysis filed in support of proposed Power Sector Transformation Plan programs implies that a single REC generated by a zero-emission resource would represent 1029 pounds of avoided CO_2 emissions. Because emissions are capped under RGGI, however, the purchase and retirement of a REC would not actually lead to verifiable CO_2 abatement. This is because RECs effectively free up room under the CO_2 emissions cap and, in doing so, lower the demand for (and thus price of) CO_2 allowances.

(This response is identical to the Company's response to PUC 1-7 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 9-32

Request:

Is the Company's expected cost/tonCO2 for RGGI allowances or RECs less than the Company's estimate of the value of a ton of CO2?

Response:

The expected cost per ton of RGGI allowances included in the Company's response to PUC 9-30 is less than the Company's estimate of the value of a ton of CO_2. In its benefit cost analysis, the Company assumed a value of $100 per ton net of embedded costs (*i.e.*, CO_2 compliance costs already reflected in retail energy prices). This is consistent with the value assumed in implementing the Rhode Island Test used for energy efficiency cost-effectiveness analysis. Based on the Company's responses to PUC 9-30 and PUC 9-31, the implied cost per ton of CO_2 for RECs would be approximately $89.70 in 2019. This is based on the Company's assumed grid CO_2 emissions factor, in which approximately 1.94 RECs would represent 1 ton of CO_2 emissions. As noted in the Company's response to PUC 9-31, RECs, even if purchased and retired, cannot be assumed to represent CO_2 abatement because of the emissions cap under RGGI, and the level of abatement implied by purchase and retirement of 1 RGGI allowance is also somewhat uncertain.

(This response is identical to the Company's response to PUC 1-8 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 9-33

Request:

Is the Company's expected cost/tonCO2 for RGGI allowances or RECs less than any of the Company's expected cost/tonCO2 in the Company's Electric Heat Initiative?

Response:

Expected costs per ton of CO_2 reduced through the Electric Heat Initiative are shown in Attachment PUC 9-33. The Company shows both lifetime average and marginal costs (*i.e.*, the cost of reductions from an incremental installation). The marginal costs, however, are the most appropriate for this comparison. Although the marginal cost per ton of CO_2 is higher than the cost per ton of CO_2 implied by RGGI allowances and RECs only when the Ground Source Heat Pump Program is included, , neither RECs nor RGGI allowances represent guaranteed additional CO_2 abatement, as discussed in the Company's response to PUC 9-32. Further details are provided in the Company's responses to PUC 9-31 and PUC 9-34.

(This response is identical to the Company's response to PUC 1-9 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuiness

CO2 TARGETS (CORRECTED in DIV 25-18)

Program Design Element	Target Levels	Targets (annual metric tons CO2)		
		2018	**2019**	**2020**
1. GSHP Program	**Mid (annual)**	**0**	**59**	**0**
	Mid (lifetime)	**0**	**1466**	**0**
2. Equipment Incentives	**Mid (annual)**	**171**	**194**	**224**
	Mid (lifetime)	**3479**	**3917**	**4577**

Total Targets (combined metric tons CO2 avoided per yer)		**2018**	**2019**	**2020**
	Mid (annual)	**171**	**253**	**224**
	Mid (lifetime	**3479**	**5383**	**4577**

PROGRAM COSTS

Program Design Element	Program Cost	2018	2019	2020
1. GSHP Program	O&M		$ 95,000	
	Capital		$ 500,000	
	Total	**$ -**	**$ 595,000**	**$ -**
2. Equipment Incentives	Incentive Pool	$207,500	$236,250	$265,000
	Labor & Administration	$44,640	$44,640	$44,640
	Total	**$ 252,140**	**$ 280,890**	**$ 309,640**
3. Community Based Outreach	O&M	$ 95,500	$ 95,500	$ 95,500
	Capital	**$ -**	**$ -**	**$ -**
	Total	**$ 95,500**	**$ 95,500**	**$ 95,500**
4. Oil-dealer training	O&M	$ 61,000	$ 61,000	$ 61,000
	Capital	**$ -**	**$ -**	**$ -**
	Total	**$ 61,000**	**$ 61,000**	**$ 61,000**
Total		**$ 408,640**	**$ 1,032,390**	**$ 466,140**

Lifetime Abatement Cost Estimates	**Notes**	**2018**	**2019**	**2020**
Average CO2 abatement (lifetime) **Total EHI Program**	Total program costs divided by lifetime CO2 avoided	**$ 117**	**$ 192**	**$ 102**
Marginal CO2 abatement (lifetime)	Incentive costs divided by lifetime CO2 avoided			
GSHP		n/a	$ 406	n/a
Equipment Incentives		$ 60	$ 60	$ 58
Total EHI Program		**$ 60**	**$ 154**	**$ 58**

PUC 9-34

Request:

Was the voluntary purchase of RECs and RGGI when the price of each is below a certain price, such as the company's benchmark for CO2, considered for meeting the Company's GHG reduction targets?

Response:

No. First, as discussed in the Company's responses to PUC 9-32 and PUC 9-33, the purchase and retirement of RECs alone does not imply any additional CO_2 abatement. In addition, at current cap levels and with the potential for emissions leakage outside of the RGGI region, the purchase and retirement of RGGI allowances does not provide certainty of additional CO_2 abatement.

Second, the Company's CO_2 reduction targets and incentive are intended to reward the Company for its effectiveness in driving emissions reductions outside of the electric sector. Electrification of heat will be essential for Rhode Island to meet its greenhouse gas reduction goals, and therefore the Company proposes to achieve these goals through the Electric Heat Initiative. For example, the 2050 Pathway in The Rhode Island Executive Climate Change Coordinating Council's "Rhode Island Greenhouse Gas Emissions Reduction Plan" implies an annual conversion rate of approximately 13,000 customers per year to heat pumps every year between now and 2050.

The proposed incentive was designed to reward the Company for effectively targeting highly-emitting customers, maximizing participation on a fixed incentive budget, and encouraging proper system design and utilization.

(This response is identical to the Company's response to PUC 1-10 in Docket No. 4780.)

Prepared by or under the supervision of: Timothy Roughan and Meghan McGuinness

PUC 9-35

Request:

Please provide the expected or target rebate, per month, that would be paid to participant in the EV Off-Peak Charging Rebate program. Please indicate which months are summer which months are winter rebate months. Please provide the number of hours participants are expected to charge their vehicles per month during on- and off-peak hours. Please reference or include supporting material, and indicate which are Rhode Island-specific data.

Response:

As described in the Company's response to Division 32-29, a copy of which is provided as Attachment PUC 9-35-1 for ease of reference, the Company estimated that participants might earn up to $18 per month in summer months (June – September) and up to $12 per month in winter months (October – May). This estimate assumes that participants perform 100 percent of their charging at home during off-peak hours in all months to maximize their benefit.

Home charging session lengths vary, depending upon the voltage level (120v Level 1, or 240v Level 2), amperage of the charger, the vehicle's acceptance rate from a Level 2 charger if available (3.3KW or greater), and the amount of battery required to charge.

For average daily commuters with a Level 2 charger, the Company expects regular overnight charging to satisfy most, if not all, of these drivers' regular charging needs. A Level 2 charger can supply 10 to 20 miles of range per hour, according to the US Department of Energy.[1] Given this, a single nine-hour off-peak charging session (for example, starting at 9:00 p.m. and ending at 6:00 a.m.) could deliver 90 to 180 miles of battery range. One of the purposes of the proposed pilot is to validate this assumption and gather more specific data on Rhode Island drivers' charging levels and charging patterns.

(This response is identical to the Company's response to PUC 1-11 in Docket No. 4780.)

[1] See Attachment PUC 9-35-2 for this reference.

Prepared by or under the supervision of: Carlos Nouel

Division 32-29

Request:

NOTE: The references to responses to division data requests refer to docket 4770.

Refer to PST-1, Chapter 5, page 3 regarding the Company's estimate of the likely monthly earnings for customers under the proposed off-peak charging rebate:

a. Provide all calculations underlying the estimate of these monthly earnings values, in machine-readable format with formulas intact.
b. Provide the Company's hourly EV charging assumptions underlying these earnings values.

Response:

a. Please see Attachment DIV 32-29. The Company assumed that an average electric vehicle (EV) uses 30 kWh to travel 100 miles, for an efficiency of 0.30 kWh per mile. Assuming an average 12,000 electric miles driven per year, an EV will use approximately 3,600 kWh per year, or 300 kWh per month. If 100 percent of a drivers' usage could be conducted during the off-peak, a driver could earn 300 kWh * $0.06/kWh for $18 per month in summer, and 300 kWh * $0.04/kWh for $12 per month in all other months.

   The Company reserves the right to change the value per kWh as necessary during this pilot to achieve the pilot goals.

b. The Company's estimate of these earnings values assumes 100 percent of kWh are charged during the off-peak period eligible for the rebate (9:00 p.m. until the following day 1:00 p.m.).

(This response is identical to the Company's response to Division 10-29 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

Potential EV driver earnings per month under Off-Peak Charging Rebate Program

Average electric vehicle efficiency (kWh per mi)	0.3
Average electric miles driven annually	12,000
Average electricity used annually (kWh)	3600
Average electricity used monthly (kWh)	300
Summer month rebate per kWh	$ 0.06
Non-summer month rebate per kWh	$ 0.04
Potential earnings per summer month	**$ 18**
Potential earnings per non-summer month	**$ 12**

Office of
ENERGY EFFICIENCY & RENEWABLE ENERGY

Vehicle Charging

Home » Vehicle Charging

The standard J1772 electric power receptacle (right) can receive power from Level 1 or Level 2 charging equipment. The CHAdeMO DC fast charge receptacle (left) uses a different type of connector.

To get the most out of your plug-in electric vehicle (also known as an electric car or EV), you must charge it on a regular basis. Charging frequently maximizes the range of all-electric vehicles and the electric-only miles of plug-in hybrid electric vehicles. Drivers can charge at home, at work, or in public places. While most drivers do more than 80% of their charging at home and it is often the least expensive option, workplace and public charging can complement residential charging.

TYPES OF CHARGERS

Charging your EV requires plugging into a charger connected to the electric grid, also called electric vehicle supply equipment (EVSE). There are three major categories of chargers, based on the maximum amount of power the charger provides to the battery from the grid:

- **Level 1: Provides charging through a 120 V AC plug and does not require installation of additional charging equipment. Can deliver 2 to 5 miles of range per hour of charging. Most often used in homes, but sometimes used at workplaces.**
- **Level 2: Provides charging through a 240 V (for residential) or 208 V (for commercial) plug and requires installation of additional charging equipment. Can deliver 10 to 20 miles of range per hour of charging. Used in homes, workplaces, and for public charging.**
- **DC Fast Charge: Provides charging through 480 V AC input and requires highly specialized, high-powered equipment as well as sp**

(Plug-in hybrid electric vehicles typically do not ha

deliver 60 to 80 miles of range in 20 minutes of charging. Used most often in public charging stations, especially along heavy traffic corridors.

Charging times range from less than 30 minutes to 20 hours or more based on the type of EVSE, as well as the type of battery, how depleted it is, and its capacity. All-electric vehicles typically have more battery capacity than plug-in hybrid electric vehicles, so charging a fully depleted all-electric vehicle takes longer.

In addition to the three types above, wireless charging uses an electro-magnetic field to transfer electricity to an EV without a cord. The Department of Energy is supporting research to develop and improve wireless charging technology. Wireless chargers are currently available for use with certain vehicle models.

TYPES OF PLUGS

Most modern chargers and vehicles have a standard connector and receptacle, called the SAE J1772. Any vehicle with this plug receptacle can use any Level 1 or Level 2 EVSE. All major vehicle and charging system manufacturers support this standard, so your vehicle should be compatible with nearly all non-fast charging workplace and public chargers.

Fast charging currently does not have a consistent standard connector. SAE International, an engineering standards-setting organization, has passed a standard for fast charging that adds high-voltage DC power contact pins to the SAE J1772 connector currently used for Level 1 and Level 2. This connector enables use of the same receptacle for all levels of charging, and is available on certain models like the Chevrolet Spark EV. However, other EVs (the Nissan Leaf and Mitsubishi i-MiEV in particular) use a different type of fast-charge connector called CHAdeMO. Fortunately, an increasing number of fast chargers have outlets for both SAE and CHAdeMO fast charging. Lastly, Tesla's Supercharger system can only be used by Tesla vehicles and is not compatible with vehicles from any other manufacturer. Tesla vehicles can use CHAdeMO connectors through a vehicle adapter.

Directives, Delegations & Requirements
FOIA
Inspector General
Privacy Program
Small Business
Staff & Contractor Resources

FEDERAL GOVERNMENT

The White House
USA.gov

Web Policies • Privacy • No Fear Act • Whistleblower Protection • Information Quality • Open Gov • Accessibility

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PUC 9-36

Request:

In National Grid's response to Sierra Club 1-16 in Docket No. 4780, National Grid states, "As part of the EV Off-Peak Charging Rebate, the Company will evaluate the technical capability of Level 2 electric vehicle supply equipment to function as residential revenue-grade meters.

a. In what way will this evaluation be similar to the streetlight metering pilot conducted as part of Docket No. 4513? In what ways will it be similar?

b. Why does National Grid believe the results of the proposed study will be different from the results of the study conducted in Docket No. 4513?

Response:

a. In Docket No. 4513, the Company conducted a pilot metering program for municipal-owned street lights that tested the meter accuracy of the customer-owned devices. The general conclusion reached through this testing was that the network lighting controls did not meet industry standards for accuracy. At this time, given limited resources and the results of the Docket No. 4513 study, the Company plans to evaluate the technical capability of Level 2 electric vehicle supply equipment through monitoring research by others in the industry on the topic, including the Plug-in Electric Vehicle Submetering Pilot underway in California, rather than perform its own testing of residential EV chargers.

b. The Company does not know how the results of industry research on residential EV chargers will compare to the study conducted in Docket No. 4513.

(This response is identical to the Company's response to PUC 1-12 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

PUC 9-37

Request:

Regarding the proposal to electrify portions of National Grid's fleet:

a. Where will these vehicles be housed, recharged, and registered?

b. Will the vehicles be used in other jurisdictions? If so, will some of the costs of these vehicles be paid for by ratepayers in other jurisdictions?

Response:

a. The vehicles will be housed at various existing Company locations throughout the State of Rhode Island and will be recharged at that same location. The vehicles will be registered in Rhode Island as well.

b. No, the vehicles will not be used in other jurisdictions.

(This response is identical to the Company's response to PUC 1-13 in Docket No. 4780.)

Prepared by or under the supervision of: Carlos Nouel

PUC 9-38

Request:

In National Grid's response to Sierra Club 1-24 in Docket No. 4780, National Grid states, "Although funding for the beneficial heat electrification will originate from both the EE and PST programs, most part of the implementation and delivery… will be undertaken by the same internal staff."

a. How will employees understand when they are working on EE versus PST initiatives?

b. How will these employees' time be tracked and accounted for appropriately in the different programs' administrative costs.

c. For electric heating activities that are identical in the EE and PST programs, would National Grid's metric achievement measurement and incentive structure identical for these activities? If not, why not?

Response:

a. National Grid has established accounting processes that define what employees charge for various initiatives. Steps in that process include establishing funding projects for portfolios or funding streams, work orders for project levels, and operations for different types of work. These three components are parts of an accounting string. In developing new accounting strings and modifying existing ones, a financial assurance team works with employees to differentiate funding streams and work types in accordance with regulatory orders. That process results in clearly defined and named funding projects and work orders, which reside in cost centers within the organization. The financial assurance team then manages the database, communication, training, and review necessary for appropriate accounting. An employee will understand they are working on energy efficiency versus Power Sector Transformation because they 1) were part of an established process that clearly defined one versus the other; 2) new accounting strings clearly differentiate the work streams; and 3) communication and training of new accounting has been provided. National Grid has experience with this process, such as various funding streams for Rhode Island energy efficiency and more recently with New York REV.

b. In addition to the response above, National Grid has established accounting processes specific to charging time and reporting administrative costs. The accounting strings described above, which will differentiate between energy efficiency and Power Sector Transformation, are used in the SAP time entry system. Components of accounting strings also define where the costs are reported and their source, such as administrative costs that will be reported as either energy efficiency or Power Sector Transformation, labor or non-labor. Charges are reviewed for appropriateness at several intervals throughout the year by various teams.

c. The Company believes that, in the long run, heat electrification efforts should place CO_2 reductions at the core of utility metrics and incentives, as currently described in the performance incentive mechanisms framework. In the short run, the metrics and incentive structures will not be identical between the two programs, as the energy efficiency program retains its focus on energy savings reductions. Over the course of the three-year Power Sector Transformation Plan, the Company will work with the PUC and stakeholders to consider options for harmonization of metrics and incentive structures over the longer term.

(This response is identical to the Company's response to PUC 1-14 in Docket No. 4780.)

Prepared by or under the supervision of: Mackay Miller

PUC 9-39

Request:

For any PST program or subprogram described as a "pilot" or "demonstration" by the National Grid

a. Please confirm that the primary objective of the activity is to learn.

b. For each activity that also would count toward a proposed incentive and is supported by capital spending, please explain why an incentive beyond the return on investment is justified.

c. For each activity that also would count toward a proposed incentive and is not supported by capital spending, please confirm that no existing program incentive or proposed program incentive could apply to the activity in the case that the Company's pilot or demonstration leads to a full-fledged program deployment.

Response:

a. Three Power Sector Transformation Plan programs are described as a "pilot" or "demonstration" project: the Electric Transportation Initiative, the Energy Storage System Initiative, and the Solar demonstration Program.

The primary objective of the Electric Transportation Initiative is market development for electric vehicles and charging. Because the market for vehicles and charging is in its infancy in Rhode Island, the Company's Electric Transportation Initiative is structured as a three-year pilot to test multiple market development strategies. Under the Electric Transportation Initiative, three components are further characterized as pilots or demonstrations: the Off-Peak Charging Rebate Pilot, the Charging Station Demonstration Program, and the Discount Pilot for Direct Current Fast Charging Station Accounts. As the end of these three-year programs approaches, the Company will return to the Public Utilities Commission with proposals to continue some or all of the activities as required to meet customers' needs.

For the Energy Storage System Initiative, the Company noted in PST Book 1, Bates Page 137, that, "[t]o effectively integrate energy storage, utilities must become involved with this technology early on, developing process improvements and methods to properly and efficiently take advantage of the benefits that storage can provide. It is for this reason that the Company proposes an Energy Storage System Initiative in its clean energy portfolio." The Company noted three major objectives of this proposal on Bates Page 138 of PST Book 1: maximize quantifiable benefits; advance internal research and development; and promote energy awareness through educational outreach to community and youth organizations.

For the Solar demonstration program, the Company's stated objective described in PST Book 1, Bates Page 147, is to allow the Company to learn from the siting, permitting, construction, interconnection, and operation of solar PV systems, to benefit customers and solar developers as renewable projects progress forward, and to spur new market growth.

b. **Electric Transportation Initiative**

The Company has proposed two performance incentives related to the Electric Transportation Initiative:

- EV-Off Peak Charging Rebate Participation, measured by number of participants in the program; and
- Electric vehicles, measured by the number of incremental EVs adopted above forecasted levels.

Two of the proposed components of the initiative include capital:

- Charging Station Demonstration Program; and
- Company Fleet Expansion.

The Charging Station Demonstration Program may contribute to achievement of the EV targets because increasing charging station availability should help to enable EV adoption. Achievement of these targets, however, will also rely heavily on the Company's outreach and education efforts. An incentive beyond the return on charging station capital is warranted because it will reward the effectiveness of the Company's overall efforts to drive EV adoption, which is critical to state's greenhouse gas policy goals.

Company Fleet Expansion would not count toward a proposed incentive.

Energy Storage System Initiative: This project will contribute to but not be sufficient to meet the targets for the Company's proposed Utility-Owned Storage Performance Incentive Mechanism. An incentive for energy storage is warranted to support Company efforts to help spur cost effective deployment in recognition of the role that cost-effective storage can play in supporting Rhode Island's clean energy and climate goals.

Prepared by or under the supervision of: Kayte O'Neill

Solar Program: This project is not specifically linked to any proposed incentive. Any reductions in peak demand due to this program could potentially contribute to the FCM and Monthly Transmission Peak Demand Reduction targets. However, peak reductions would not count toward the FCM Peak Demand Reduction target if the Company bids this capacity into the ISO-NE Forward Capacity Market.

c. This question only applies to certain components of the Electric Transportation Initiative (e.g., Off-Peak Charging Rebate Pilot, and education and outreach that would support incremental EV adoption). There are no existing program incentives that could apply to these proposed Electric Transportation Initiative activities in the event that it becomes a full-fledged program.

(This response is identical to the Company's response to PUC 1-15 in Docket No. 4780.)

Prepared by or under the supervision of: Kayte O'Neill

PUC 9-40

Request:

Regarding National Grid's proposed increase to the Residential customer charge:

a. What, increase to National Grid proposed to the Residential distribution charge would be necessary to achieve the proposed revenue requirement if the customer charge remained at $5/customer-bill?

b. What would be the average annual value of such an increase to existing residential net metering customers? Please provide the number of existing residential net metering customers and their annual kWh generation used to respond to this data request.

Response:

a. Please see Attachment PUC 9-40. Under a $5/customer-bill charge, the volumetric distribution charge would be $0.04787 per kWh to achieve the proposed revenue requirement. For the purposes of this response, the Company assumed that the same rate would be proposed for A-16 and A-60 customers.

b. The Company does not have load or generation information from net metered customers. The net meter used for these customers only measures the net usage less any generation over the billing period. Therefore, the Company is unable to calculate this value.

(This response is identical to the Company's response to PUC 1-16 in Docket No. 4780.)

Prepared by or under the supervision of: Kayte O'Neill

The Narragansett Electric Company
Illustrative Rate Design for Residential Rates A-16 / A-60
Based on a $5.00 per Month Customer Charge

Line		Billing Units	Illustrative Rates	Revenue
		(a)	(b)	(c)
1	Revenue Allocation			**$167,491,395**
2				
3	Customer Charge:			
4	Monthly Bills- A-16	4,847,495	$5.00	$24,237,475
5	Monthly Bills- A-60	437,171	$5.00	$2,185,855
6	**Customer Charge Revenue**	5,284,666		**$26,423,330**
7				
8	Energy-based Charge:			
9	kWh Sales- A-16	2,723,228,532	$0.04787	$130,360,950
10	kWh Sales- A-60	223,496,800	$0.04787	$10,698,792
11	**Distribution Charge Revenue**	2,946,725,332		**$141,059,742**
12				
13	Rate A-16 Rev			$154,598,425
14	Rate A-60 Rev			$12,884,647
15				
16	**Total Revenue**			**$167,483,072**
17				
18	Difference			($8,323)
19				
20	Customer costs per month	Sch. HSG-1C-1 (REV-1), Line 23		$9.38
21	Demand costs per kW-month	Sch. HSG-1C-1 (REV-1), Line 10		$11.00
22	Use kW X		0.50	$5.50
23	Total			$14.88
24	Use		A-16	$5.00
25			A-60	$5.00
26				
27	Item		Source	
28	Line 1		Schedule HSG-3 (REV-1), Line 47	
29	Lines 4-5, Column (a)		Schedule HSG-4L (REV-1), Lines 10-11	
30	Lines 4-5, Column (b)		Per information request PUC 9-40	
31	Lines 9-10, Column (a)		Schedule HSG-4L (REV-1), Lines 10-11	
32	Lines 9-10, Column (b)		Calculated to produce revenue requirement	