Niagara Mohawk Power Corporation
d/b/a National Grid

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION FOR ELECTRIC AND GAS SERVICE

Corrections and Updates Testimony and Exhibits of:

Joshua Nowak
Maureen Heaphy
Dr. Kimbugwe A. Kateregga
Electric Customer Panel
Gas Customer Panel

Book 1

July 10, 2017

Submitted to:
New York State Public Service Commission
Case 17-E-0238
Case 17-G-0239

Submitted by:
Niagara Mohawk Power Corporation

nationalgrid

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

Joshua C. Nowak

Dated: July 10, 2017

Q. Please state your name and business address.

A. My name is Joshua C. Nowak. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am employed by National Grid USA Service Company, Inc., a subsidiary of National Grid USA ("National Grid"), as Director of Regulatory Strategy & Integrated Analytics in the Regulation and Pricing function.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in Economics from Boston College. I have worked for several years as a consultant in the energy industry at ScottMadden, Inc. (and its predecessor firm, Sussex Economic Advisors, LLC) and Concentric Energy Advisors, Inc., and as an economist at RTI International. As a consultant, I provided economic, financial, and strategic advisory services to clients in regulated utility industries. I joined National Grid in 2017 in my current role where I am responsible for regulatory efforts related to capital structure, cost of capital, and strategic planning matters across National Grid's multiple U.S. operating companies and service territories. In my current position, I am familiar with the financing activities of Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or the "Company").

Q. Have you previously testified before any regulatory commissions?

A. Yes. I have testified before various regulatory commissions in electric and gas utility proceedings. Specifically, I have testified before the Public Utilities Commission of New Hampshire, the Public Utility Commission of Texas, the Railroad Commission of Texas, and the Regulatory Commission of Alaska.

Q. Did the Company previously submit testimony concerning the Company's capital structure?

A. Yes. The Company submitted the direct testimony of Stephen H. Caldwell as part of its cases filed April 28, 2017. Mr. Caldwell presented and supported Niagara Mohawk's proposed capital structure and overall cost of capital in these proceedings.

Q. What is the purpose of your corrections and updates testimony?

A. The purpose of my testimony is to adopt the testimony of Stephen H. Caldwell. I have reviewed Mr. Caldwell's prepared direct testimony, and agree with the analysis and conclusions therein.

Q. Do you adopt Mr. Caldwell's prepared direct testimony, dated April 28, 2017 in this matter as your own, including the conclusions and supporting analyses?

A. I do.

Q. Are there any other changes you wish to make to your testimony at this time?

A. No, there are not.

Q. Does this conclude your corrections and updates testimony?

A. Yes, it does.

C&U Testimony of
Maureen P. Heaphy

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

Maureen P. Heaphy

Dated: July 10, 2017

Q. Please state your name and business address.

A. My name is Maureen P. Heaphy. My business address is One MetroTech Center, Brooklyn, New York 11201.

Q. Are you the same Maureen P. Heaphy who previously submitted prepared direct testimony as part of Niagara Mohawk Power Corporation d/b/a National Grid's ("Niagara Mohawk" or the "Company") April 28, 2017 filing?

A. Yes, I am. The terms defined in my direct testimony have the same meanings here.

Q. What is the purpose of your corrections and updates testimony?

A. The purpose of my corrections and updates testimony is to provide certain corrections regarding employee thrift plan costs, to update FTE projections that affect labor expense for the Rate Year, and to update variable pay expense levels.

Q. Do you sponsor any exhibits as part of your corrections and updates testimony?

A. Yes. With respect to the updated FTE projections for the Rate Year, I sponsor Exhibit___ (MPH-1CU), which was prepared under my supervision and direction. In addition, I understand that the Revenue Requirements Panel is sponsoring Exhibit__ (RRP-11CU), Schedule 17, Workpaper 2, to correct and update the information regarding the incremental increase in costs related to the Company's thrift plan that I discuss in this testimony.

Q. Please describe the corrections you are making to employee thrift plan costs.

A. I am making two corrections. First, my prepared direct testimony at page 57 of 62 indicated that effective January 1, 2018, certain changes to the Company's 401(k) plan would result in an incremental cost of $1.831 million over the three year term of the Local 97 contract ("Blue Book"), and Niagara Mohawk's allocated portion of that expense was $0.427 million in the Rate Year, as reflected in the revenue requirement. In calculating this expense, ten employees that should have been assigned as inactive employees were assigned as active employees. Inactive employees are employees who are on an unpaid leave of absence. Such employees do not participate in the Company's thrift plan and should not have been included in determining the incremental Rate Year forecast.

Q. What is the impact to the Rate Year forecast of thrift plan expense as a result of reassigning these employees?

A. Removing the inactive employees reduces Rate Year electric thrift expense by $1,376 and gas thrift expense by $262. This information has been provided to the Company's Revenue Requirements Panel and is shown in Exhibit__ (RRP-11CU), Schedule 17, Workpaper 2. This correction was also noted in the Company's response to Information Request No. DPS-185 (JPC-15).

Q. What is the second correction you are making to employee thrift plan costs?

A. My prepared direct testimony at page 57 of 62 indicated that the change to core contributions into the 401(k) plan accounts for members of Local 97C results in an allocation of incremental costs to Niagara Mohawk of $0.272 million in the Rate Year. As explained in the Company's response to Information Request No. DPS-011 (JPC-5), the Company mistakenly reflected these costs on a calendar year basis instead of a fiscal year basis. The correction changes Niagara Mohawk's allocated portion of the cost from $0.272 million to $0.256 million. This information has been provided to the Company's Revenue Requirements Panel and is shown in Exhibit__ (RRP-11CU), Schedule 17, Workpaper 2.

Q. Please describe the update you are making with respect to FTEs.

A. My prepared direct testimony at page 7 of 62 stated that the Company expected to fill 231 incremental positions before the end of the Rate Year. The Company now expects to fill 228.3 incremental positions before the end of the Rate Year, as shown in Exhibit __ (MPH-1CU). The reasons for the change in FTEs are discussed in corrections and updates testimony sponsored by the respective Gas and Electric Infrastructure and Operations Panels. The revenue requirement impacts associated with the change (which is also reflected in Data Year 1 and Data Year 2) are discussed in the corrections and updates testimony of the Revenue Requirements Panel.

Q. Please describe the update you are making with respect to variable pay.

A. My prepared direct testimony at page 27 of 62 indicated that the Company was proposing to include approximately $18.096 million of variable compensation expense in its electric revenue requirement in this proceeding for the Rate Year and $4.112 million in the gas revenue requirement for a total of $22.208 million; approximately $22.911 million for Data Year 1, split $18.659 million for electric and $4.252 million for gas; and approximately $23.593 million for Data Year 2, split $19.218 million for electric and $4.375 million for gas. The Company has updated these amounts such that it proposes to include approximately $18.059 million in variable compensation expense in its electric revenue requirement for the Rate Year and $4.144

million in the gas revenue requirement for a total of $22.203 million; approximately $22.907 million for Data Year 1, split $18.622 million for electric and $4.285 million for gas; and approximately $23.589 million for Data Year 2, split $19.179 million for electric and $4.410 million for gas. The reasons for these changes are discussed in the corrections and updates testimony sponsored by the Revenue Requirements Panel.

Q. Does this conclude your corrections and updates testimony?

A. Yes, it does.

Index of Exhibits

Exhibit __ (MPH-1CU)

National Grid Incremental FTEs

National Grid Incremental FTE's
Corrections and Updates Filing
Rate Year Ending March 31, 2019

							Count		
No.	Position	Company	Driver	Labor Type	Function	Testimony	RY 2019	DY 2020	DY 2021
1	Estimator	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
2	Estimator	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
3	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
4	Program Manager	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
5	Program Manager	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
6	Program Manager	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
7	Program Manager	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
8	Analyst	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
9	Analyst	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
10	Analyst	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
11	Analyst	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
12	Regional Operator	NMPC	Workforce Optimization	Management	110-Control Center Ops	EIOP	1	1	1
13	Regional Operator	NMPC	Workforce Optimization	Management	110-Control Center Ops	EIOP	1	1	1
14	Regional Operator	NMPC	Workforce Optimization	Management	110-Control Center Ops	EIOP	1	1	1
15	Regional Operator	NMPC	Workforce Optimization	Management	110-Control Center Ops	EIOP	1	1	1
16	Regional Operator	NMPC	Workforce Optimization	Management	110-Control Center Ops	EIOP	1	1	1
17	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
18	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
19	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
20	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
21	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
22	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
23	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
24	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
25	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
26	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
27	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
28	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	1	1	1
29	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
30	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
31	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
32	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
33	Tran Line Worker A 3/C	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
34	Transmission Line Worker Helper	NMPC	Succession Planning	Union	110-Electric Process & Engineering	EIOP	0	1	1
35	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
36	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
37	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
38	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
39	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
40	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
41	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
42	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1

Exhibit __(MPH-1CU)
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National Grid Incremental FTE's
Corrections and Updates Filing
Rate Year Ending March 31, 2019

No.	Position	Company	Driver	Labor Type	Function	Testimony	Count RY 2019	DY 2020	DY 2021
43	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
44	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
45	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
46	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
47	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
48	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
49	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
50	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
51	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
52	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
53	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
54	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
55	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
56	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
57	Line Mechanic A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
58	M&R Work Coordinator	NMPC	Workforce Optimization	Management	110-Operations Support	EIOP	1	1	1
59	M&R Work Coordinator	NMPC	Workforce Optimization	Management	110-Operations Support	EIOP	1	1	1
60	M&R Supervisor	NMPC	DG	Management	110-Operations Support	EIOP	1	1	1
61	Mapping Technician	NMPC	DG	Union	110-Operations Support	EIOP	1	1	1
62	Mapping Technician	NMPC	DG	Union	110-Operations Support	EIOP	1	1	1
63	Mapping Technician	NMPC	DG	Union	110-Operations Support	EIOP	1	1	1
64	Mapping Technician	NMPC	DG	Union	110-Operations Support	EIOP	1	1	1
65	Mapping Technician	NMPC	Workforce Optimization	Union	110-Operations Support	EIOP	1	1	1
66	Mapping Technician	NMPC	Workforce Optimization	Union	110-Operations Support	EIOP	1	1	1
67	Mapping Technician	NMPC	Workforce Optimization	Union	110-Operations Support	EIOP	1	1	1
68	Reliability Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
69	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
70	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
71	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
72	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
73	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
74	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
75	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
76	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
77	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
78	Distribution Engineer	NMPC	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
79	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
80	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
81	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
82	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	0	1
83	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	0	1
84	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1

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National Grid Incremental FTE's
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Rate Year Ending March 31, 2019

No.	Position	Company	Driver	Labor Type	Function	Testimony	Count RY 2019	DY 2020	DY 2021
85	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
86	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
87	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
88	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
89	Distribution Engineer	NMPC	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
90	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
91	Distribution Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
92	Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
93	Distribution Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	0	1
94	Transmission Planner	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
95	Engineer/Sr Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
96	Engineer/Sr Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
97	Engineer/Sr Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
98	Engineer/Sr Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	0	1
99	Engineer/Sr Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
100	Sr Engineer/Lead Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
101	Engineer/Sr Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
102	Engineer/Sr Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
103	Engineer/Sr Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	0	1	1
104	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
105	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
106	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
107	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
108	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
109	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	0	1	1
110	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	0	1	1
111	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	0	1	1
112	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	0	1	1
113	Engineer/Sr Engineer	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	0	1	1
114	Engineer/Sr Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
115	Analyst\Senior Analyst	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
116	Analyst\Senior Analyst	ServCo	DSP Functions	Management	110-Electric Process & Engineering	EIOP	1	1	1
120	Associate Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
121	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
122	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
123	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
124	Sr. Engineer/Lead Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
125	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
126	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
127	Engineer/Senior Engineer	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	0	1
128	Engineer/Senior Engineer	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
129	Engineer/Senior Engineer	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1

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Rate Year Ending March 31, 2019

No.	Position	Company	Driver	Labor Type	Function	Testimony	Count RY 2019	Count DY 2020	Count DY 2021
130	Engineer/Senior Engineer	ServCo	Workforce Optimization	Management	110-Electric Process & Engineering	EIOP	1	1	1
131	Engineer/Senior Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
132	Engineer/Senior Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
133	Engineer/Senior Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	1	1	1
134	Engineer/Senior Engineer	ServCo	DG	Management	110-Electric Process & Engineering	EIOP	0	1	1
135	Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
136	Engineer	NMPC	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
137	Director	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
138	Manager	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
139	Manager	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
140	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
141	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	1	1	1
142	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
143	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
144	Analyst	ServCo	Core Capex Growth	Management	110-Electric Process & Engineering	EIOP	0	1	1
145	Senior Specialist	NMPC	Workforce Optimization	Management	110-Electric Asset Management	EIOP	1	1	1
146	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
147	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
148	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
149	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
150	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
151	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
152	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
153	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
154	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
155	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
156	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
157	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
158	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
159	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
160	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
161	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
162	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
163	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
164	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
165	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
166	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
167	Relay Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
168	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
169	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
170	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
171	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1

Exhibit __(MPH-1CU)
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Corrections and Updates
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National Grid Incremental FTE's
Corrections and Updates Filing
Rate Year Ending March 31, 2019

No.	Position	Company	Driver	Labor Type	Function	Testimony	Count RY 2019	DY 2020	DY 2021
172	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
173	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
174	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	1	1	1
175	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
176	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
177	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
178	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
179	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	1	1
180	Communications Tester A	NMPC	Succession Planning	Union	210-Jurisdictions-NY	EIOP	0	0	1
187	NWA Program Manager	NMPC	Workforce Optimization	Management	180-New Energy Solutions	EIOP	1	1	1
188	NWA Program Manager	NMPC	Workforce Optimization	Management	180-New Energy Solutions	EIOP	1	1	1
189	NWA Program Manager	NMPC	Workforce Optimization	Management	180-New Energy Solutions	EIOP	1	1	1
190	NWA Program Manager	NMPC	Workforce Optimization	Management	180-New Energy Solutions	EIOP	1	1	1
191	Program Manager	NMPC	DSP Functions	Management	180-New Energy Solutions	ECP	1	1	1
194	Program Manager	NMPC	DSP Functions	Management	160-Customer Engagement	ECP	1	1	1
195	Program Manager	ServCo	DSP Functions	Management	160-Customer Engagement	ECP	1	1	1
196	Program Manager	ServCo	DSP Functions	Management	160-Customer Engagement	ECP	1	1	1
197	Program Manager	NMPC	DSP Functions	Management	160-Sales & Program Operations	ECP	1	1	1
198	Program Manager	NMPC	DSP Functions	Management	160-Sales & Program Operations	ECP	1	1	1
199	Program Manager	NMPC	DSP Functions	Management	160-Sales & Program Operations	ECP	1	1	1
200	Facilility Supervisor	NMPC	Workforce Optimization	Management	320-Shared Services	EIOP	1	1	1
201	Facilility Supervisor	NMPC	Workforce Optimization	Management	320-Shared Services	EIOP	1	1	1
203	Manager	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
204	Lead Consultant	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
205	Lead Consultant	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
207	Lead Consultant	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
208	Lead Consultant	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
209	Lead Consultant	NMPC	DG	Management	160-Sales & Program Operations	EIOP	1	1	1
C10	Consumer Advocate	ServCo	Energy Affordability Program	Management	160-Customer Care	SSP	1	1	1
C12	Program Manager	ServCo	DSP Functions	Management	180-New Energy Solutions	GCP	1	1	1
EA1	Associate Analyst / Analyst	ServCo	Workforce Optimization	Management	160-Energy Procurement	Elizebeth Arangio	1	1	1
EA2	Associate Analyst / Analyst	ServCo	Workforce Optimization	Management	160-Energy Procurement	Elizebeth Arangio	1	1	1
EA3	Lead Analyst	ServCo	Management Audit	Management	160-Energy Procurement	Elizebeth Arangio	1	1	1
G01	Supv Operations	NMPC	Increased OpEx Workload	Management	210-Maint & Const-NY Gas	GIOP	1	1	1
G02	Service Representative A	NMPC	Increased OpEx Workload	Union	110-Gas Process & Engineering	GIOP	2	2	2
G03	Analyst	NMPC	OpEx related to CAPEX	Management	110-Operations Support	GIOP	4	4	4
G04	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G05	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G06	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G07	Estimator	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	3	3	4
G08	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G09	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1

Exhibit __(MPH-1CU)
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National Grid Incremental FTE's
Corrections and Updates Filing
Rate Year Ending March 31, 2019

							Count		
No.	Position	Company	Driver	Labor Type	Function	Testimony	RY 2019	DY 2020	DY 2021
G10	Program Manager	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G11	Manager	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G12	Program Manager	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	2	2	2
G13	Coordinator	NMPC	OpEx related to CAPEX	Management	110-Operations Support	GIOP	2	2	2
G14	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G15	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G16	Project Manager - Ops	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G17	Program Manager	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G18	Program Manager	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	3	3	3
G19	I&R Gas Mechanic B	NMPC	OpEx related to CAPEX	Union	210-Maint & Const-NY Gas	GIOP	2	2	2
G20	I&R Gas Mechanic B	NMPC	OpEx related to CAPEX	Union	210-Maint & Const-NY Gas	GIOP	12	12	12
G21	Operations Clerk	NMPC	OpEx related to CAPEX	Union	110-Operations Support	GIOP	3	3	3
G22	Map & Record Tech A	NMPC	OpEx related to CAPEX	Union	110-Operations Support	GIOP	5	5	5
G23	Clerk	NMPC	OpEx related to CAPEX	Union	110-Gas Process & Engineering	GIOP	1	1	1
G24	Quality Inspector	NMPC	OpEx Safety Programs	Management	110-Gas Process & Engineering	GIOP	4	4	4
G28	Engineer	NMPC	OpEx related to CAPEX	Management	110-Control Center Ops	GIOP	1	1	1
G32	Safety Representative	NMPC	OpEx Safety Programs	Management	210-Maint & Const-NY Gas	GIOP	1	1	1
G34	Lead Instructor	NMPC	OpEx Safety Programs	Management	210-Maint & Const-NY Gas	GIOP	4	4	4
G35	Supv Operations	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G36	Program Manager	NMPC	OpEx Safety Programs	Management	110-Emergency Planning PMO	GIOP	1	1	1
G37	Lead Instructor	NMPC	Increased OpEx Workload	Management	210-Maint & Const-NY Gas	GIOP	4	4	4
G38	Analyst	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	2	2	2
G39	Engineer	NMPC	OpEx related to CAPEX	Management	110-Gas Process & Engineering	GIOP	1	1	1
G40	Supv Operations	NMPC	OpEx related to CAPEX	Management	210-Maint & Const-NY Gas	GIOP	1	1	1
G41	Lead Program Manager	NMPC	OpEx related to CAPEX	Management	210-Maint & Const-NY Gas	GIOP	1.3	1.3	1.3
G42	Senior Scheduler	NMPC	OpEx Safety Programs	Management	110-Gas Process & Engineering	GIOP	2	2	2
SL1	Lead Analyst	NMPC	Outdoor Lighting - NY	Management	210-Jurisdictions-NY	SLP	1	1	1
Grand Total							228.3	262.3	277.3

Exhibit __(MPH-1CU)
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Corrections and Updates
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Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

Dr. Kimbugwe A. Kateregga

Vice President, Foster Associates Consultants, LLC

Dated: July 10, 2017

Q. Please state your name and business address.

A. My name is Kimbugwe A. Katerrega. My business address is 17595 S. Tamiami Trail, Suite 260 Fort Myers, Florida 33908.

Q. Are you the same Kimbugwe A. Kateregga who previously provided testimony in this proceeding?

A. Yes. I provided direct testimony as part of Niagara Mohawk Power Corporation d/b/a National Grid's ("Niagara Mohawk" or the "Company") April 28, 2017 filing. The terms defined in my direct testimony have the same definitions here.

Q. What is the purpose of your corrections and updates testimony?

A. The purpose of my corrections and updates testimony is to correct Exhibit ___ (KAK-3) filed in support of my direct testimony. I inadvertently omitted certain graphs as part of Exhibit ___ (KAK-3), which contained workpapers in support of my testimony.

Q. Do you sponsor any exhibits as part of your corrections and updates testimony?

A. Yes. I sponsor Exhibit ___ (KAK-3CU) entitled 2016 Electric Depreciation Rate Study.

Q. Please describe the corrected information contained in Exhibit ___ (KAK-3CU).

A. This exhibit includes 11 pages containing various graphs inadvertently omitted in Exhibit __ (KAK-3). The graphs show the statistically best fitting dispersion and derived projection lives for the full placement and observation bands, the associated observed hazard rates and graduated functions, and the Company's proposed projection lives and curves for five different accounts: 353.55 (Station Equipment – RTU); 357.01 (Underground Conduit); 362.55 (Station Equipment – RTU); 369.20 (Underground Services – Conduit); and 392.21 (Transportation Equipment – Aircraft).

Q. What is the impact of the inclusion of these additional graphs?

A. As I explained above, the omission of these graphs was inadvertent. The information contained in these graphs was reflected in my analysis discussed in my direct testimony. Their inclusion now does not change my analysis or recommendations. Copies of the graphs were previously provided to Department of Public Service Staff in response to Information Request No. DPS-200 (PD-2).

Q. Does this conclude your corrections and updates testimony?

A. Yes, it does.

Index of Exhibits

Exhibit__ (KAK-3CU) 2016 Depreciation Rate Study

Exhibit __ (KAK-3CU)

2016 Depreciation Rate Study

2016 Electric Depreciation Rate Study

Niagara Mohawk Power Corporation – d/b/a National Grid

Work Papers

foster associates

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - RTU

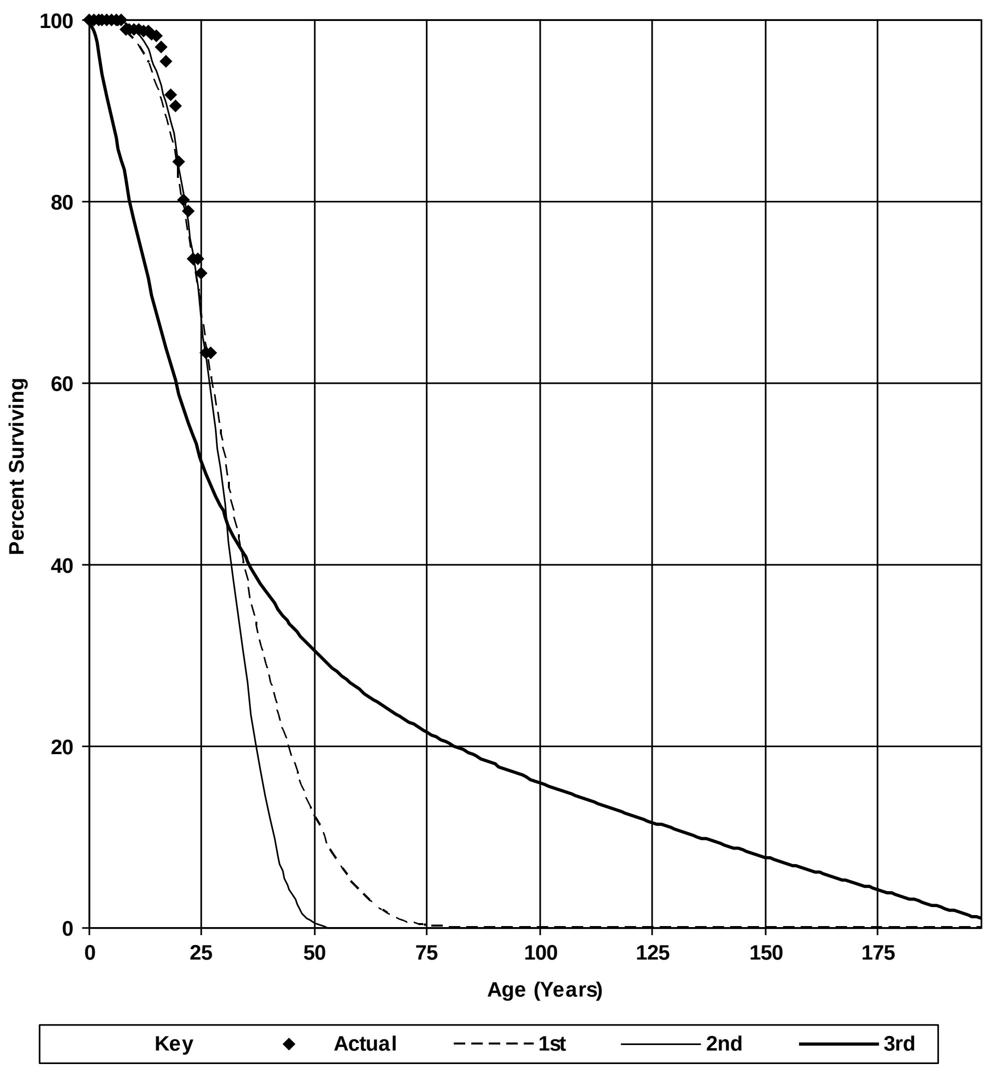
T-Cut: None

Placement Band: 1989-2015 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions 1st: 32.0-L2 2nd: 28.7-S2 3rd: 46.8-O4



Schedule E
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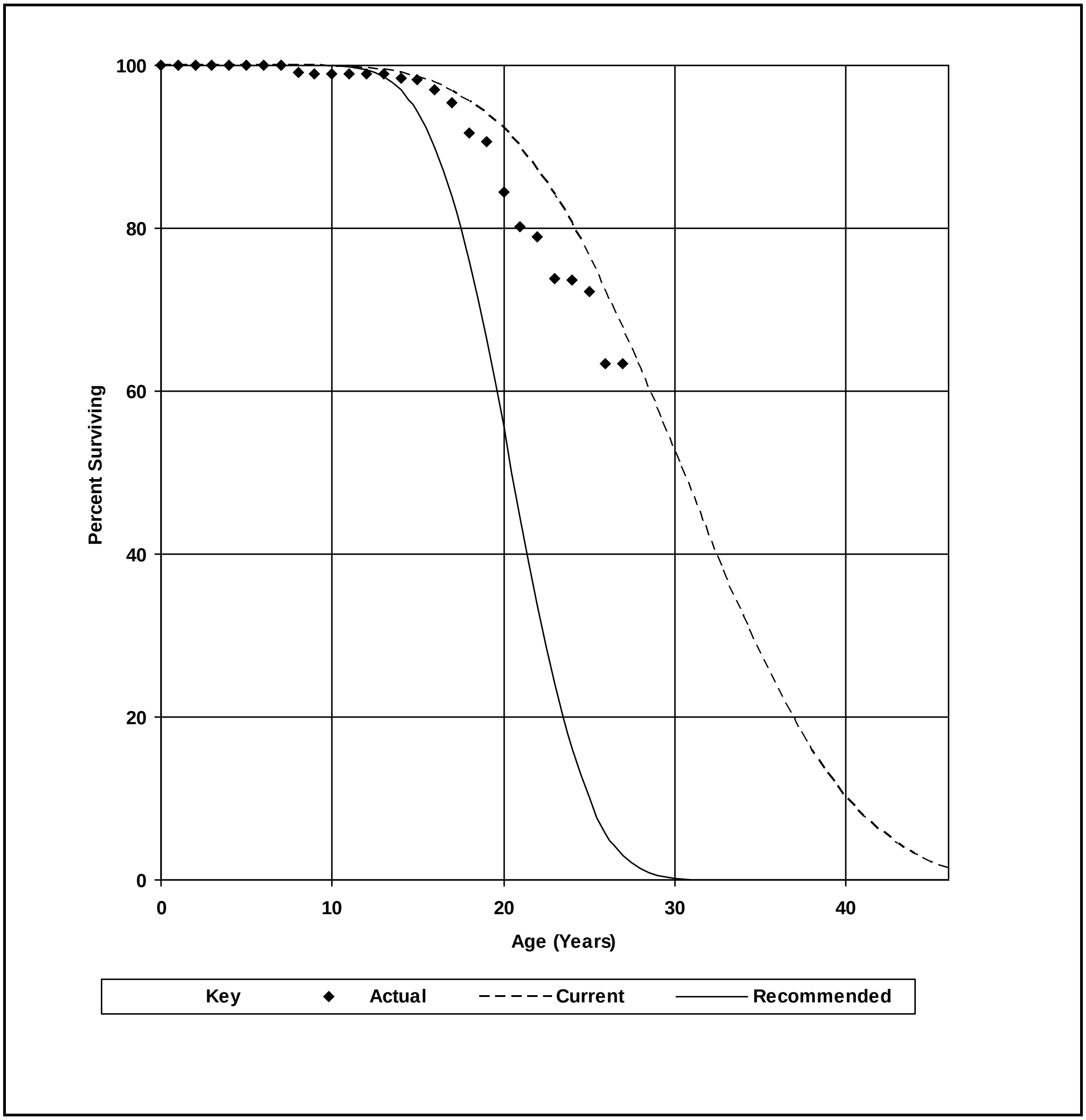
NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 353.55 Station Equipment - RTU

T-Cut: None
Placement Band: 1989-2015
Observation Band: 1996-2015

Current and Recommended Projection Life Curves Current: 30.0-S3 Recommended: 20.0-S4



Schedule E
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

Account: 357.01 Underground Conduit

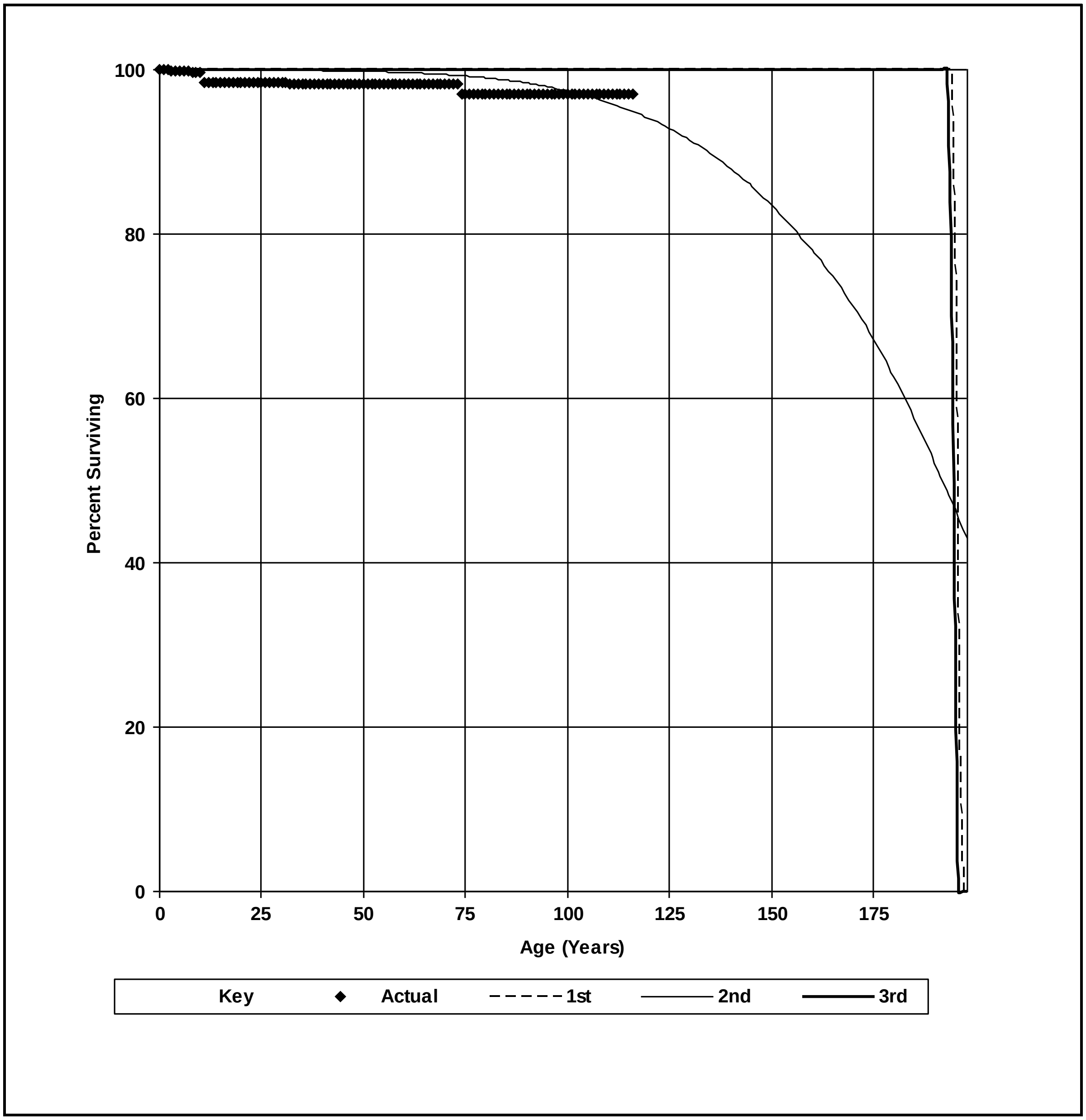
T-Cut: None

Placement Band: 1900-2015 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions 1st: 195.9-SQ 2nd: 186.6-R4 3rd: 195.0-SQ



Schedule E
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Transmission Plant

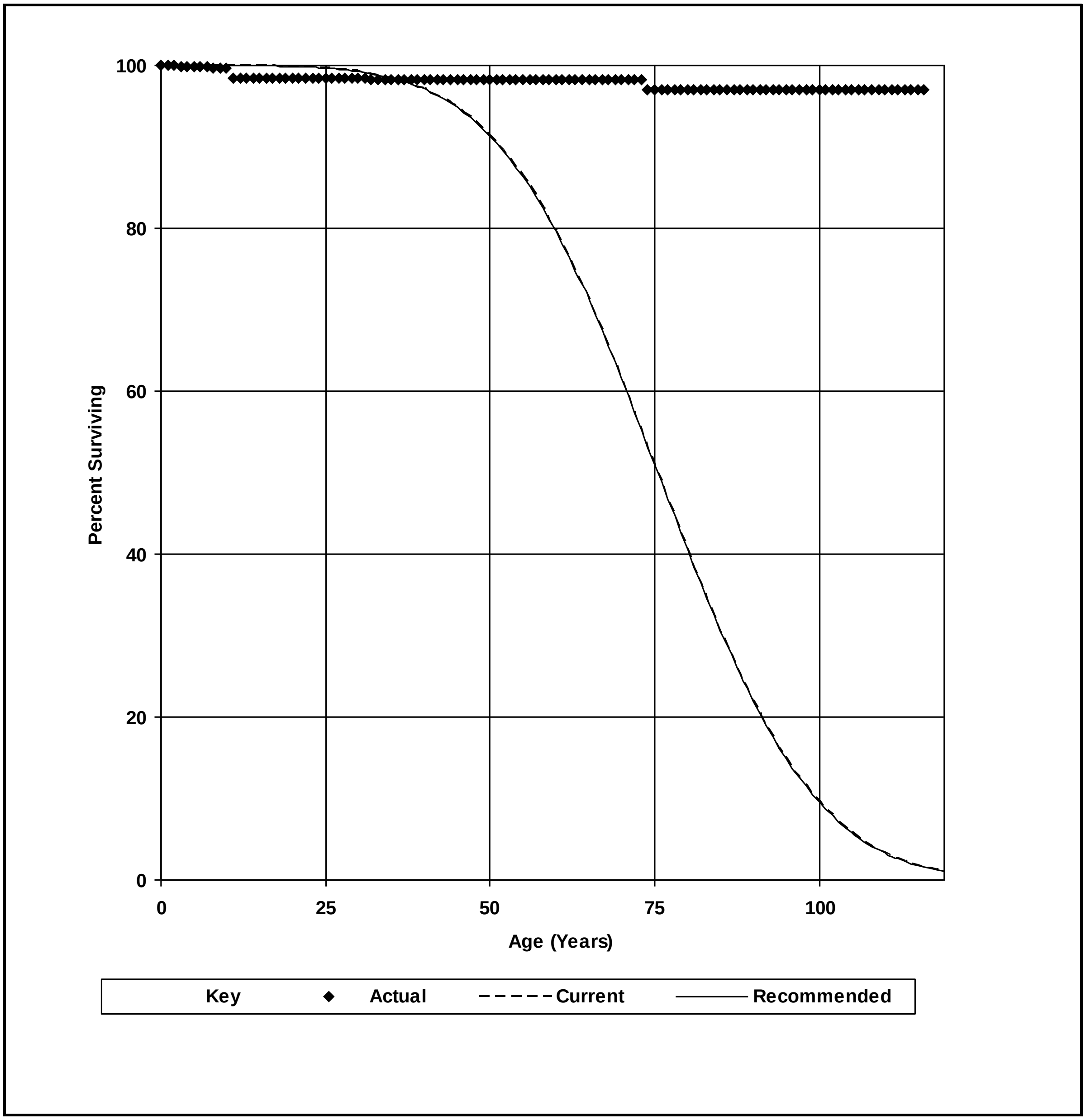
Account: 357.01 Underground Conduit

T-Cut: None

Placement Band: 1900-2015

Observation Band: 1996-2015

Current and Recommended Projection Life Curves Current: 75.0-H4 Recommended: 75.0-H4



NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipment - RTU

T-Cut: None

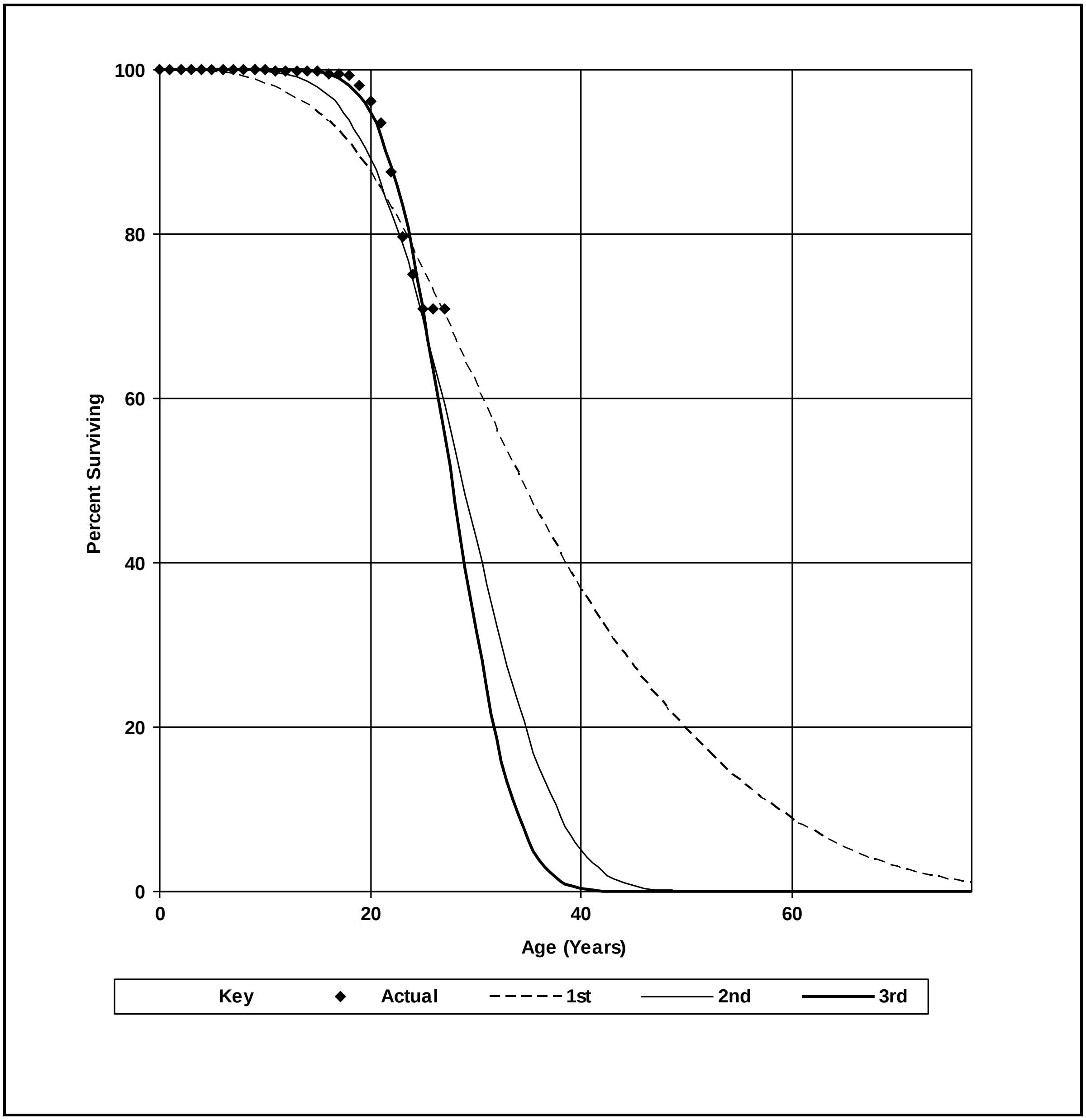
Placement Band: 1989-2015 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions

1st: 36.1-L2 2nd: 28.2-S3 3rd: 27.2-S4



NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 362.55 Station Equipment - RTU

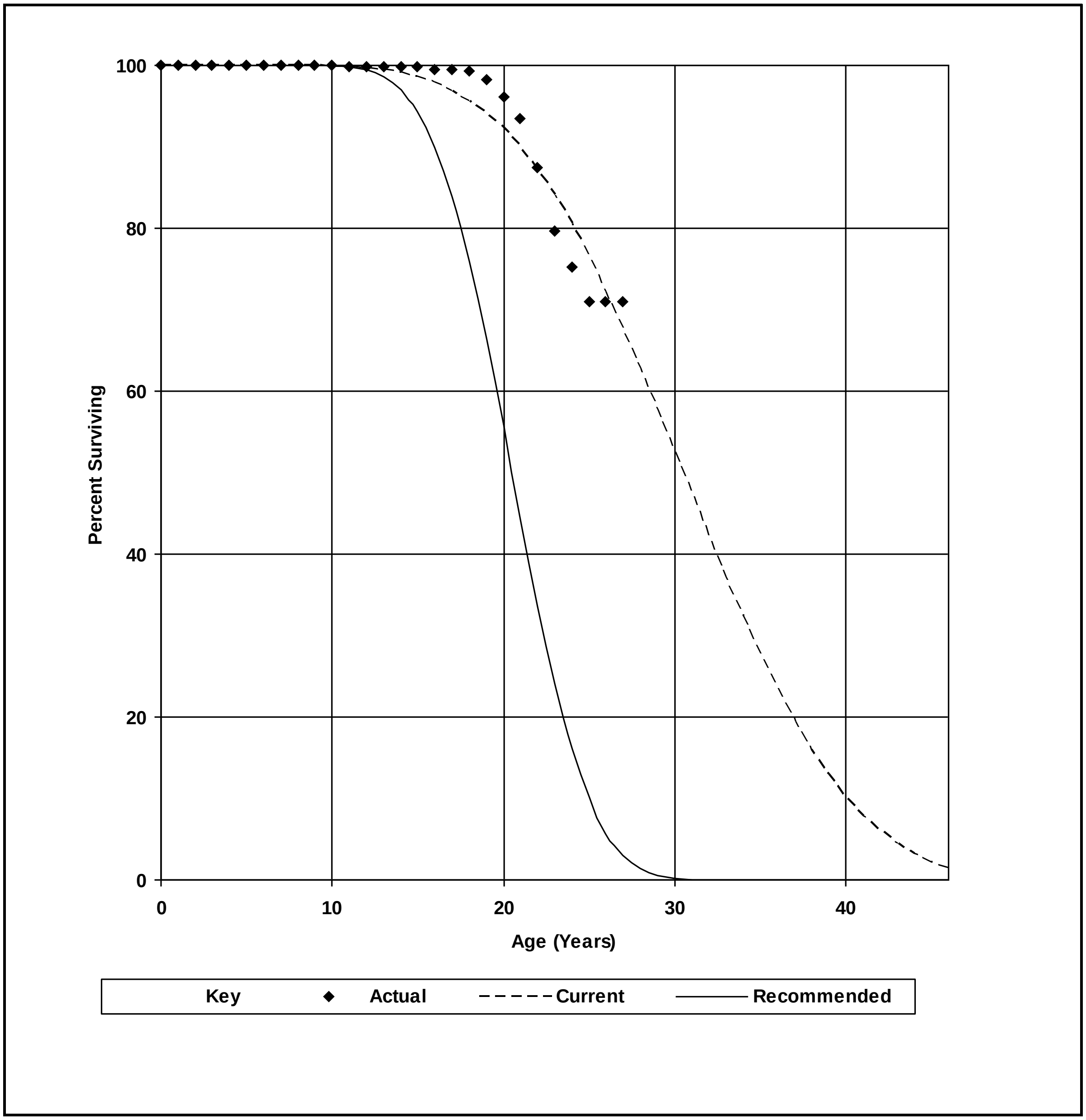
T-Cut: None

Placement Band: 1989-2015

Observation Band: 1996-2015

Current and Recommended Projection Life Curves

Current: 30.0-S3 Recommended: 20.0-S4



Schedule E
Page 1 of 1

NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

Account: 369.20 Underground Services - Conduit

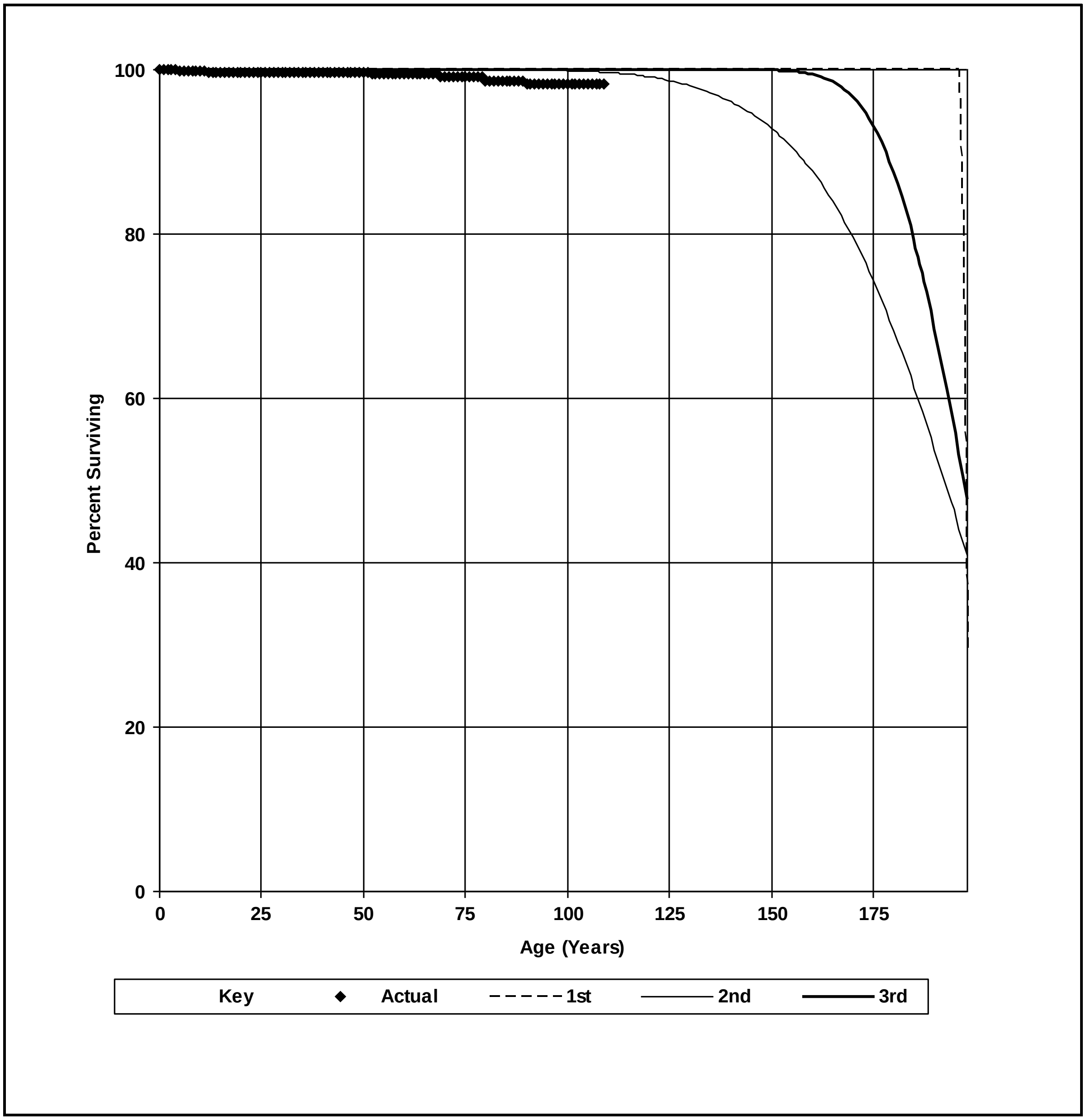
T-Cut: None

Placement Band: 1907-2015 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions **1st: 198.1-SQ 2nd: 189.6-R5 3rd: 196.7-S6**



NIAGARA MOHAWK POWER CORPORATION - ELECTRIC

Distribution Plant

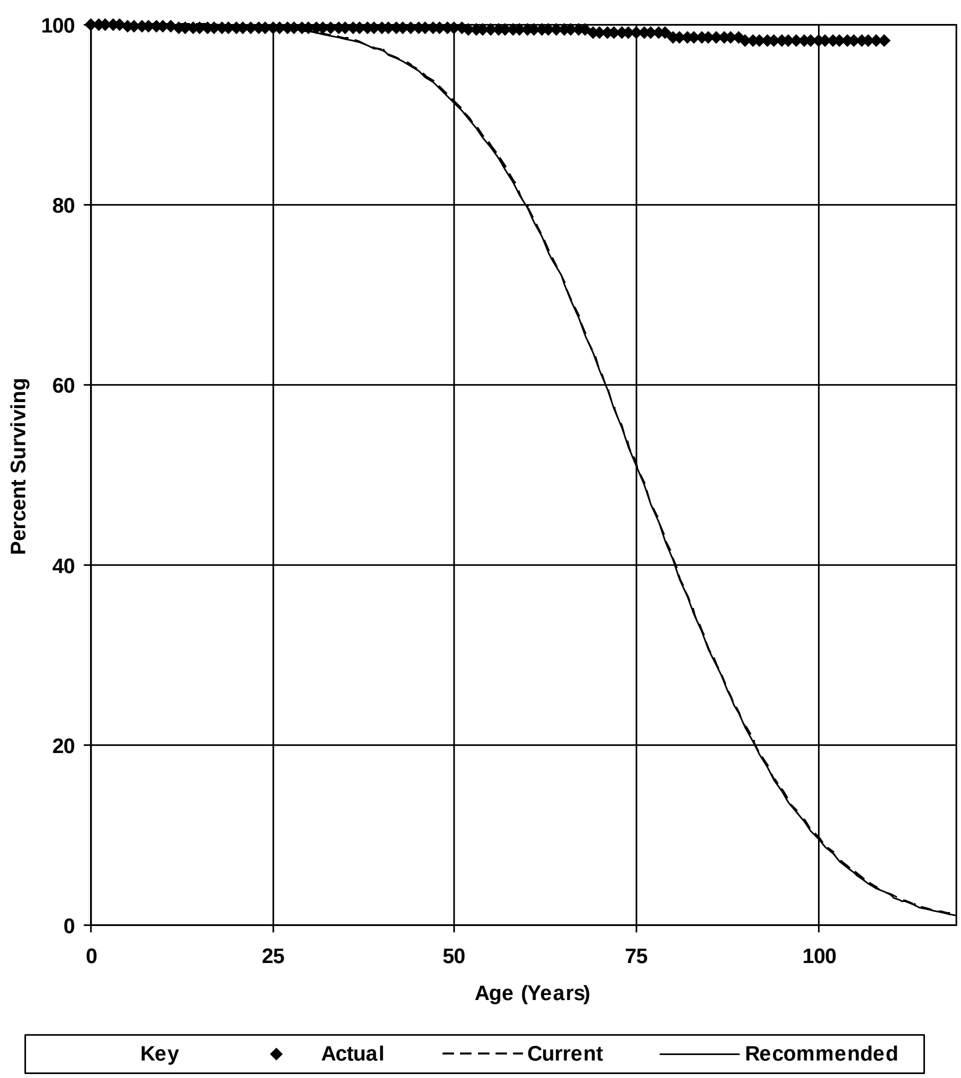
Account: 369.20 Underground Services - Conduit

T-Cut: None

Placement Band: 1907-2015

Observation Band: 1996-2015

Current and Recommended Projection Life Curves **Current: 75.0-H4** **Recommended: 75.0-H4**



NIAGARA MOHAWK POWER CORPORATION - COMMON

Schedule E
Page 1 of 1

General Plant

Depreciable

Account: 392.21 Transportation Equipment - Aircraft

T-Cut: None

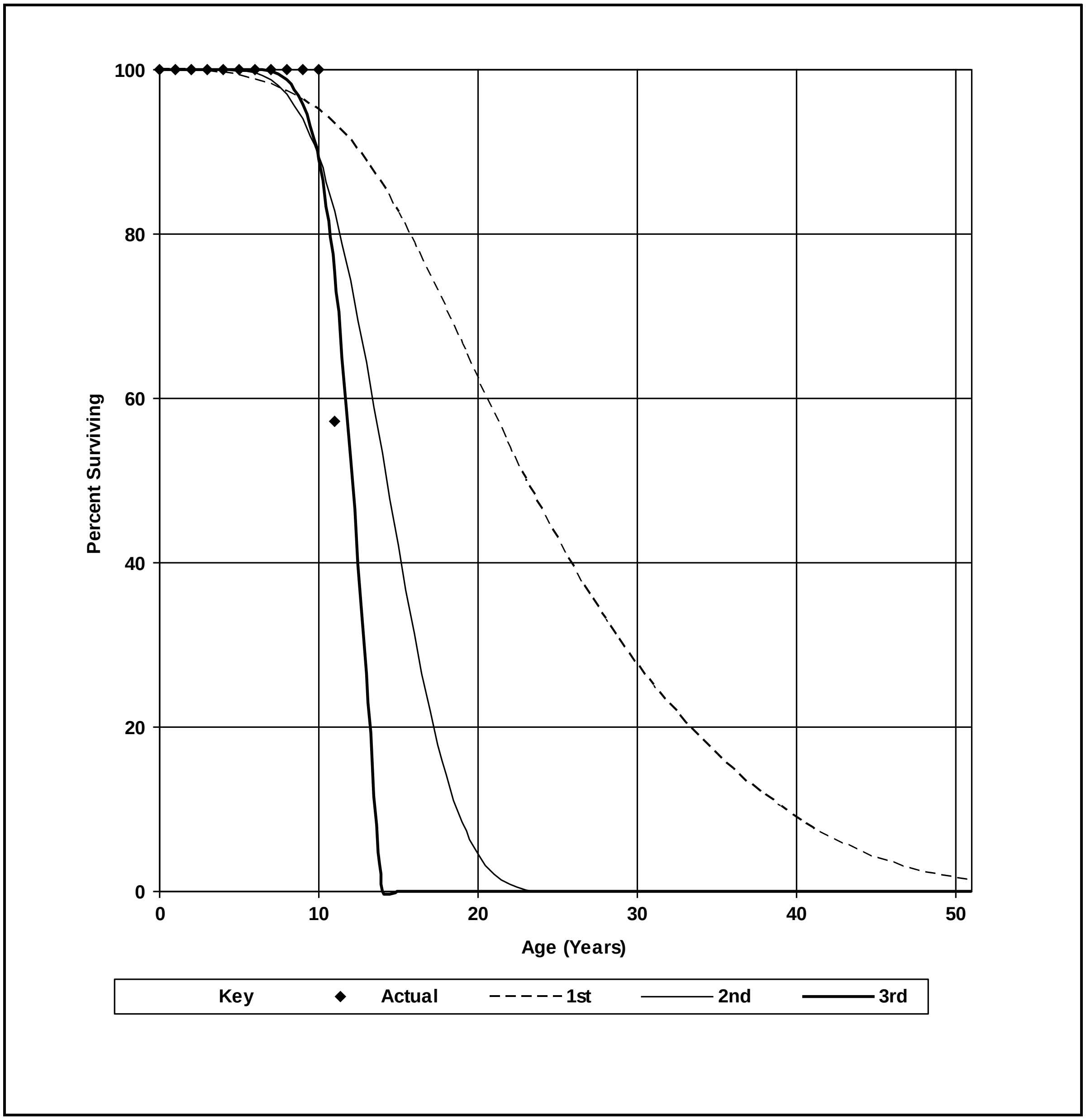
Placement Band: 1994-2008 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Survivorship Functions

1st: 24.1-L2 2nd: 13.8-S3 3rd: 11.5-R5



NIAGARA MOHAWK POWER CORPORATION - COMMON

Schedule E
Page 1 of 1

General Plant

Depreciable

Account: 392.21 Transportation Equipment - Aircraft

T-Cut: None

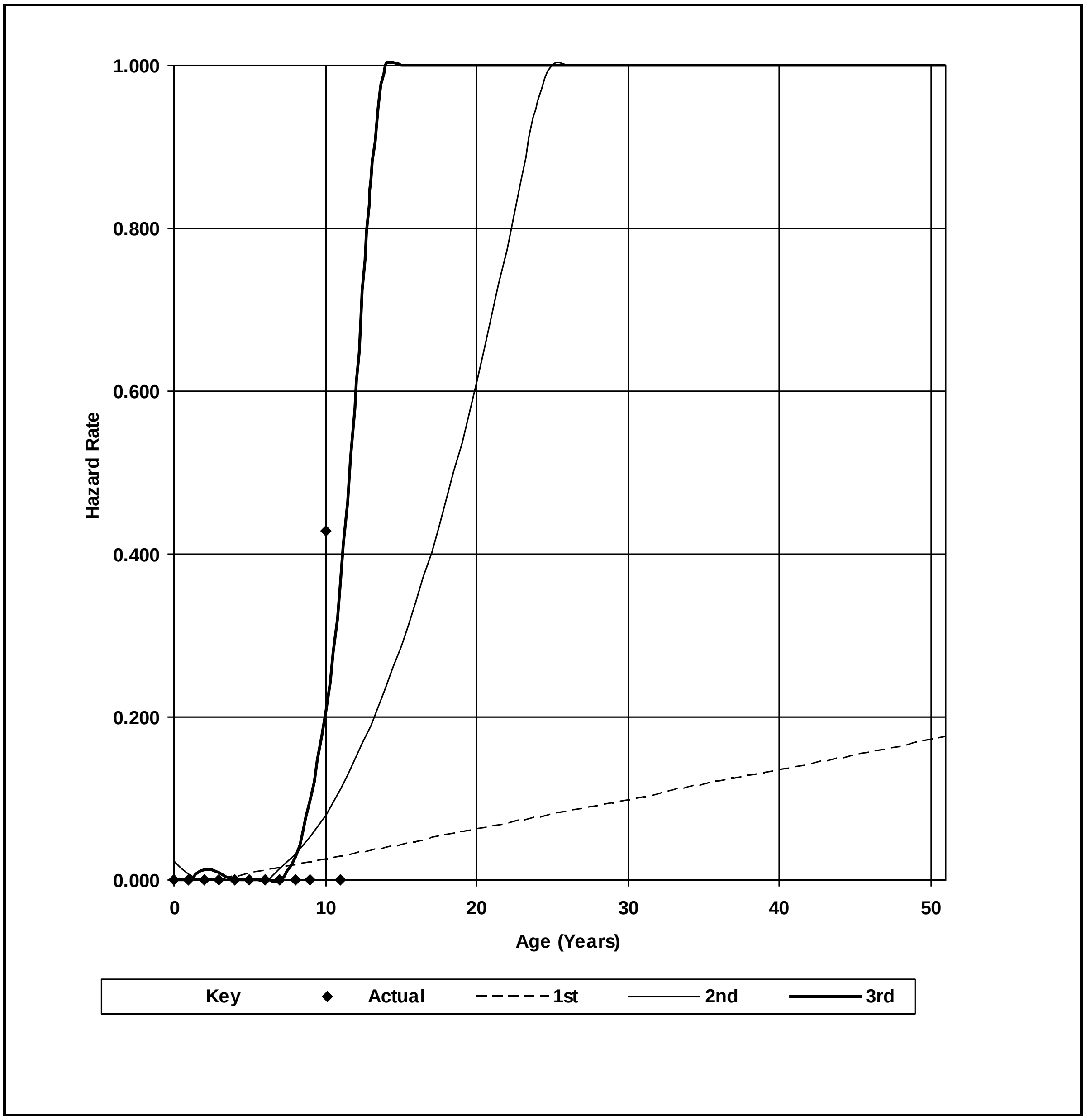
Placement Band: 1994-2008 Observation Band: 1996-2015

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Functions

1st: 24.1-L2 2nd: 13.8-S3 3rd: 11.5-R5



NIAGARA MOHAWK POWER CORPORATION - COMMON

Schedule E
Page 1 of 1

General Plant

Depreciable

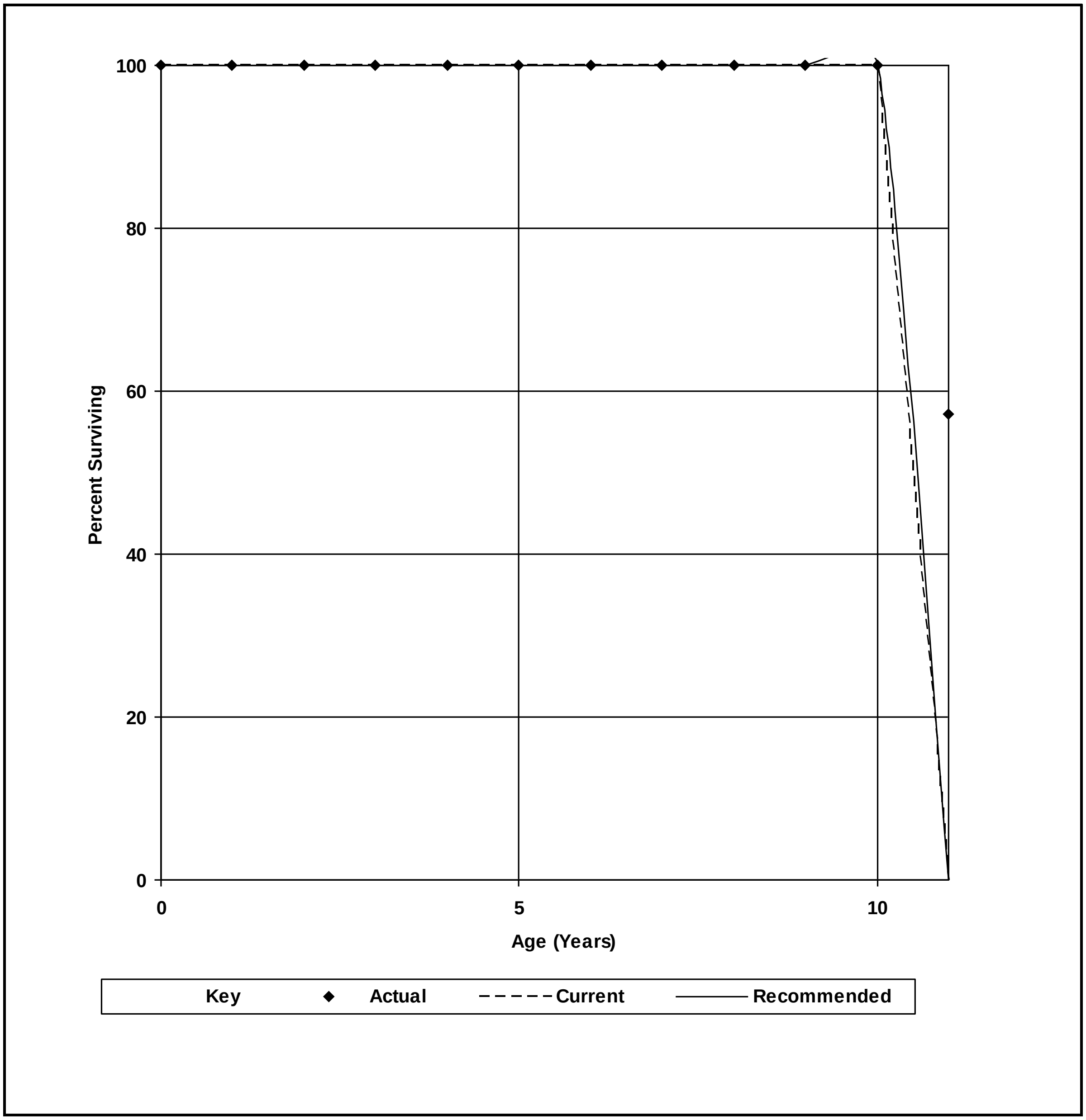
Account: 392.21 Transportation Equipment - Aircraft

T-Cut: None

Placement Band: 1994-2008

Observation Band: 1996-2015

Current and Recommended Projection Life Curves **Current: 10.0-SQ** **Recommended: 10.0-SQ**



Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

The Electric Customer Panel

Dated: July 10, 2017

Q. Please introduce the members of the Electric Customer Panel.

A. The Panel consists of Carlos A. Nouel, John F. Isberg, and James M. Molloy.

Q. Is this the same Panel that submitted testimony previously in this proceeding?

A. Yes. The Panel provided direct testimony as part of the Company's April 28, 2017 filing. The terms defined in the Panel's direct testimony have the same meanings here.

Q. What is the purpose of the Panel's corrections and updates testimony?

A. The purpose of the Panel's testimony is to identify and explain the following corrections and updates:

- <u>Energy Storage Projects</u> – The Panel provides additional details and updates the costs of the two energy storage projects discussed in the Panel's direct testimony.
- <u>Earnings Adjustment Mechanisms ("EAMs")</u> – The Panel explains corrections and updates to the EAMs section of its direct testimony.
- <u>Electric Transportation Initiative Benefit Cost Analysis ("BCA")</u> – The Panel identifies one correction to the "Electric Vehicles Benefit Cost Analysis Summary" included in Exhibit ___ (ECP-1), Schedule 8.

Q. Does the Panel sponsor any exhibits as part of its corrections and updates testimony?

A. Yes. The Panel sponsors the following exhibits that were prepared and compiled under our direction and supervision:

(i) Exhibit ___ (ECP-1CU) contains an updated summary page (Schedule 1) and updated schedules for the Company's proposed energy storage projects (Schedule 6) and electric transportation initiative (Schedule 8). For completeness and readability, the exhibit also includes the schedules from the original exhibit that are not being updated.

(ii) Exhibit ___ (ECP-5CU) contains an updated summary of EAM targets (Schedule 2), updated schedules for the Company's proposed electric Energy Efficiency EAM Energy Intensity targets (Schedules 5, 6, and 7), and an update to the summary of electric EAM net benefits (Schedule 8). For completeness and readability, the exhibit also includes the schedules from the original exhibit that are not being updated.

(iii) Exhibit ___ (ECP-6CU) contains relevant portions of the Information Requests referenced in the Panel's corrections and updates testimony.

I. <u>Energy Storage Projects</u>

Q. Please explain the updates to the energy storage projects.

A. Consistent with the Commission's "Order on Distributed System Implementation Plan Filings" issued on March 9, 2017 in Case 16-M-0411 ("March 2017 DSIP Order"), the Company is proposing to implement two energy storage projects to increase the penetration of distributed energy resources ("DER") and enable the Company to learn more about the impact of DER on the electric system.

Because the Company was still evaluating potential project options at the time the Panel's direct testimony was filed, the Company included an Example Project as a proxy for purposes of modeling the revenue requirement. The Example Project assumed the deployment of a 2.5 MW/8 MWh substation connected lithium-ion battery. The costs of the Example Project were doubled to account for two storage projects in the revenue requirement. The Panel explained in its direct testimony that it would update the actual projects selected and the associated costs in the Company's corrections and updates filing.

Q. Has the Company selected the two projects to be deployed?

A. Yes. After an evaluation process that considered projects from the Company's non-wires alternatives list, the Company selected the two projects that will be deployed to test storage technology, the Kenmore Project and the

East Pulaski Project. Both projects utilize a similarly-sized energy storage system, estimated at 2 MW/3 MWh, and are described in more detail below. Consistent with the March 2017 DSIP Order, each project will evaluate different grid functions. In addition, throughout the deployment and operation of the projects the Company will examine storage system functionality to identify and leverage any additional benefits of the storage systems.

<u>Kenmore Project</u> – The project will test the use of energy storage to alleviate a supply constraint at the Kenmore substation. The substation is supplied by three sub-transmission cables that are forecast to surpass their normal-rated capacity in the near future. The energy storage system will be designed to supply energy at peak times to reduce the load carried by the sub-transmission system. This will allow the Company to defer installing additional sub-transmission capacity in the area.

<u>East Pulaski Project</u> – The project will test the use of energy storage to alleviate an "n-1" distribution constraint at the East Pulaski substation. If a failure occurs in the nearby local network, the substation may need to supply energy to an increased number of customers, resulting in the possibility of the substation surpassing its rated capacity and impacting reliability. This condition has occurred, on average, approximately 2.5 times per year and

lasted several hours for each occurrence. The energy storage system being deployed will supply energy to the distribution system to reduce the peak load on the transformer during an abnormal condition. Further, because of forecast area load growth, the substation transformer is projected to exceed its peak capacity in 2020. This project also will help defer the need for future investment upgrades.

Q. What are the updated costs and benefits for the two storage projects?

A. The costs include a capital investment of $4.634 million in the Rate Year for each project (total of $9.268 million) and O&M expense of $0.02 million in Data Year 1 and Data Year 2 for each project (total of $0.04 million in each Data Year), as shown in Exhibit ___ (ECP-1CU), Schedule 6. The total costs are less than the estimated costs for the Example Project. The updated costs have been provided to the Revenue Requirements Panel to calculate the updated revenue requirements.

The benefits of the storage projects include avoided generation capacity costs, avoided distribution capacity upgrades, enhanced reliability, and wholesale market revenues. An updated BCA is included in Exhibit ___ (ECP-1CU), Schedule 6.

II. EAMs

Q. Please summarize the corrections and updates to the EAMs section of the Panel's direct testimony.

A. The Company is making corrections and updates to the System Efficiency, Energy Efficiency (electric), and Energy Efficiency (gas) EAMs, as well as EAM-related updates to the Benefits and Costs section of the Panel's direct testimony.

A. System Efficiency

Q. What are the corrections and updates to the System Efficiency EAM?

A. The System Efficiency EAM is composed of three metrics: (i) Peak Reduction; (ii) Substation Load Factor; and (iii) DER Utilization. The Company is making two corrections and updates to the Peak Reduction metric.

First, the Company discovered an error in the calculation of the 2016 weather-normalized system peak baseline. Line 1 of page 46 of 84 of the Panel's direct testimony indicated a 2016 weather-normalized system peak baseline of 6,737 MW. The correct figure should be 6,846 MW. The correction is explained in the Company's responses to Information Requests Nos. DPS-022

(MZS-3) and DPS-025 (MZS-6), copies of which are included in Exhibit ___ (ECP-6CU), Schedules 1 and 2.

Second, in responding to Information Request No. DPS-379 (RAC-8), the Company realized that it inadvertently failed to include New York State Energy Research and Development Authority ("NYSERDA") estimates for the energy efficiency portion of the Peak Reduction metric. *See* Exhibit ____ (ECP-6CU), Schedule 5. Including NYSERDA estimates results in the need to update the Peak Reduction targets. Exhibit ___ (ECP-5CU), Schedule 2, contains the updated targets.

Q. Does the change to the Peak Reduction targets require a corresponding change to the Panel's direct testimony?

A. Yes. Table 3 on page 47 of 84 of the Panel's direct testimony summarized the Peak Reduction targets. The table is being revised to reflect the updated Peak Reduction targets as follows:

Table 3 – Proposed Peak Reduction Targets and Basis Points (Updated)

Annual Peak Reduction Targets (MW) and Basis Points (bps)					
	2017	**2018**	**2019**	**2020**	**Basis Points**
Minimum	159	155	167	193	9 bps
Target	235	271	330	394	14 bps
Maximum	393	469	566	669	30 bps

B. <u>Energy Efficiency (Electric)</u>

Q. What are the corrections and updates to the electric Energy Efficiency EAM?

A. The electric Energy Efficiency EAM is composed of two metrics: (i) Incremental Energy Efficiency and (ii) Energy Intensity. The Company is making a correction to the Energy Intensity metric.

As explained in the response to Information Request No. DPS-131 (JT-1), a copy of which is included in Exhibit ___ (ECP-6CU), Schedule 3, in developing the Energy Intensity targets, the Company used an earlier sales forecast instead of the most recent 2017-2020 kWh forecast that was used to develop the Company's sales forecast in the rate filing. Because of the change in energy intensity trends in the 2017-2020 kWh forecast, the Company is updating the Energy Intensity targets. Schedules 2, 5, 6, and 7 of Exhibit ___ (ECP-5CU) reflect the corrected Energy Intensity targets.

Q. Does the correction require a corresponding change to the Panel's direct testimony?

A. Yes. Table 7 on page 56 of 84 of the Panel's direct testimony summarized the Energy Intensity targets. The table is being revised to reflect the updated targets as follows:

Table 7 – Proposed Energy Intensity Targets and Basis Points (Updated)

Residential: Year-Over-Year Energy-Intensity Targets (%) and Basis Points (bps)				
	2017	**2018**	**2019**	**2020**
Minimum	0.84% (2 bps)	0.85% (2 bps)	0.86% (3 bps)	0.86% (4 bps)
Target	1.29% (3 bps)	0.98% (3.5 bps)	0.99% (4.5 bps)	1.00% (5 bps)
Maximum	1.75% (8.5 bps)	1.32% (8.5 bps)	1.34% (9 bps)	1.35% (10 bps)
Commercial: Year-Over-Year Energy-Intensity Targets (%) and Basis Points (bps)				
	2017	**2018**	**2019**	**2020**
Minimum	0.88% (2 bps)	0.89% (2 bps)	0.90% (3 bps)	0.91% (4 bps)
Target	1.09% (3 bps)	1.10% (3 bps)	1.11% (4.5 bps)	1.12% (5 bps)
Maximum	1.36% (8.5 bps)	1.38% (8.5 bps)	1.40% (9 bps)	1.42% (10 bps)
Low-Income: Year-Over-Year Energy-Intensity Targets (%) and Basis Points (bps)				
	2017	**2018**	**2019**	**2020**
Minimum	0.02% (0.5 bps)	0.09% (1 bps)	0.09% (1 bps)	0.09% (1 bps)
Target	0.10% (0.75 bps)	0.53% (1.5 bps)	0.53% (1.5 bps)	0.53% (1.5 bps)
Maximum	0.53% (3 bps)	1.06% (3 bps)	1.25% (3 bps)	1.27% (3 bps)

In addition, at page 57 of 84 of the Panel's direct testimony, the Company described the percentage increase in improvement required to meet the Energy

Intensity targets. The percentages referenced in the testimony at lines 1 through 9 are being updated to account for the updated targets as follows:

> For residential customers, the minimum target represents a 22 percent improvement in the trendline slope, the mid-point target represents a 40 percent improvement, and the maximum target represents an 87 percent improvement. For commercial customers, who have a less steep projected rate of decline in energy intensity, the minimum target represents a 34 percent improvement in the trendline slope, the mid-point target represents a 65 percent improvement, and the maximum target represents a 106 percent improvement. Exhibit ___ (ECP-5CU), Schedules 5 and 6 show the proposed residential and commercial targets.

C. Energy Efficiency (Gas)

Q. What are the corrections and updates to the gas Energy Efficiency EAM?

A. The Company is correcting line 5, page 70 of 84, of the Panel's direct testimony. The sentence should be corrected to state that the Company proposes "a program-based gas Energy Efficiency metric," not an "outcome-based" metric. The correction is made in accordance with the Company's response to Information Request No. DPS-282 (LMR-7), a copy of which is included in Exhibit ___ (ECP-6CU), Schedule 4.

D. Updates to EAMs Benefits and Costs

Q. Please describe the updates to the EAMs Benefits and Costs section of the Panel's direct testimony.

A. The Company is making two updates. First, as described by the Revenue Requirements Panel, the Company is updating its forecast electric and gas rates bases. These updates result in a change in the value of a basis point. Exhibit ___ (ECP-5CU), Schedule 8, has been updated to reflect the updated basis point values. In addition, the exhibit contains an update to the benefits and cost portion of the schedule to reflect the change in the Peak Reduction targets and the costs of the energy storage projects.

Q. Do these changes require a corresponding update to the Panel's direct testimony?

A. Yes. Lines 19 through 21 on page 68 of 84 and lines 1 through 3 on page 69 of 84 are being updated as follows:

> As shown in Exhibit ___ (ECP-5CU), Schedule 8, the Company estimates the net present value ("NPV") of EAM-supporting activities to be $492.8 million over the years 2017-2020, if it achieves all the maximum targets; $303.1 million if it achieves all mid-point targets; and $156.5 million if it achieves all minimum levels.

In addition, lines 11 through 16 on page 69 of 84 are being updated as follows:

> The proposed NPV of earnings levels over 2017-2020 would be $118.5 million if the Company achieves all maximum levels; $52.0 million if it achieves all mid-point targets; and $24.4 million if it achieves all minimum levels. A summary of the findings that form the basis for this analysis and the customer share of the net benefits can be found in Exhibit ___ (ECP-5CU), Schedule 8.

III. <u>Electric Transportation Initiative BCA</u>

Q. Please describe the corrections and updates to the Electric Transportation initiative BCA included in Exhibit ___ (ECP-1), Schedule 8, to the Panel's direct testimony.

A. Exhibit ___ (ECP-1CU), Schedule 8, is an updated BCA for the Electric Transportation initiative. The updated BCA reflects the following three corrections:

- Capital and program costs were inadvertently reflected to begin in Fiscal Year 2018. The correction shows the costs, with the exception of a small portion of program costs, beginning in the Rate Year.
- In light of the above correction, the schedule for program benefits and costs was also corrected. The original exhibit showed benefits beginning in the Rate Year. The correction shows the benefits beginning in Data Year 1, a year after the program is implemented. The Company also extended the end of the benefits and cost period by one year, from Fiscal Year 2030 to Fiscal Year 2031.

- A formula error has been corrected, resulting in $0.183 million in additional costs for the EV Grid Integration program in Data Year 2.

Q. Do the corrections change the benefit-cost ratio in the BCA?

A. No. The benefit-cost ratio remains the same for the Electric Transportation initiative.

Q. Does this conclude the Panel's corrections and updates testimony?

A. Yes.

Exhibits of
The Electric Customer Panel

Index of Exhibits

Exhibit__ (ECP-1CU)	Benefit-Cost Analyses
Exhibit__ (ECP-5CU)	Company's proposed EAMs
Exhibit__ (ECP-6CU)	Information Requests

Exhibit __ (ECP-1CU)

Benefit-Cost Analyses

Niagara Mohawk Power Corporation d/b/a National Grid
Portfolio BCA: Summary of Projects included in Revenue Requirement
($MM)

Category	Item	Total (NPV $MM)	VVO/CVR	Solar Portal	E-Commerce Portal	DRMS	Energy Storage
Benefits	Total	$65.6	$45.6	$3.0	$0.2	$7.1	$9.6
	SCT	$61.2	$45.6	$3.0	$0.2	$7.1	$5.2
	UCT	$50.6	$35.0	$3.0	$0.2	$7.1	$5.2
	RIM	$55.0	$35.0	$3.0	$0.2	$7.1	$9.6
Costs	Total	$40.7	$26.9	$1.0	$0.1	$4.3	$8.4
	CapEx split	$29.3	$17.1	$0.05	$0.1	$3.9	$8.1
	O&M split	$11.5	$9.8	$0.98	$0.09	$0.4	$0.2
	SCT	$40.7	$26.9	$1.0	$0.1	$4.3	$8.4
	UCT	$40.7	$26.9	$1.0	$0.1	$4.3	$8.4
	RIM	$40.7	$26.9	$1.0	$0.1	$4.3	$8.4
Cost-Effectiveness Tests	SCT Ratio	1.5	1.7	2.9	1.5	1.7	0.6
	UCT Ratio	1.2	1.3	2.9	1.5	1.7	0.6
	RIM Ratio	1.4	1.3	2.9	1.5	1.7	1.2

Portfolio BCA: Summary of all Projects Considered

Category	Item	Total (NPV $MM)	VVO/CVR	Solar Portal	E-Commerce Portal	DRMS	Energy Storage	Electric Vehicles	Heat Pumps
Benefits	Total	$118.2	$45.6	$3.0	$0.2	$7.1	$9.6	$37.6	$15.0
	SCT	$94.0	$45.6	$3.0	$0.2	$7.1	$5.2	$22.8	$10.0
	UCT	$51.0	$35.0	$3.0	$0.2	$7.1	$5.2	$0.0	$0.4
	RIM	$75.2	$35.0	$3.0	$0.2	$7.1	$9.6	$14.8	$5.4
Costs	Total	$76.6	$26.9	$1.0	$0.1	$4.3	$8.4	$26.8	$9.0
	CapEx split	$41.8	$17.1	$0.1	$0.1	$3.9	$8.1	$12.5	$0.0
	O&M split	$21.6	$9.8	$1.0	$0.1	$0.4	$0.2	$7.3	$2.8
	SCT	$76.6	$26.9	$1.0	$0.1	$4.3	$8.4	$26.8	$9.0
	UCT	$72.8	$26.9	$1.0	$0.1	$4.3	$8.4	$26.8	$5.3
	RIM	$72.8	$26.9	$1.0	$0.1	$4.3	$8.4	$26.8	$5.3
Cost-Effectiveness Tests	SCT Ratio	1.2	1.7	2.9	1.5	1.7	0.6	0.8	1.1
	UCT Ratio	0.7	1.3	2.9	1.5	1.7	0.6	0.0	0.1
	RIM Ratio	1.0	1.3	2.9	1.5	1.7	1.2	0.6	1.0

Exhibit______(ECP-1CU)
Schedule 1
Corrections and Updates
Page 1 of 1

VVO/CVR Benefit Cost Analysis Summary
($MM)

Category	Item	NPV ($MM)
Benefits	Total	$45.6
	SCT	$45.6
	UCT	$35.0
	RIM	$35.0

Costs	Total	$26.9
	CapEx split	$17.1
	O&M split	$9.8
	SCT	$26.9
	UCT	$26.9
	RIM	$26.9

Cost-Effectiveness Tests	SCT Ratio	1.7
	UCT Ratio	1.3
	RIM Ratio	1.3

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
Benefit	Avoided Generation Capacity Costs	Y	Y	Y	$10.91	24%		
	Avoided LBMP	Y	Y	Y	$24.11	53%		
	Net Avoided CO2	Y			$10.58	23%		
	TOTAL BENEFITS	$45.6	$35.0	$35.0	$45.6			
Cost	Program Administration Costs	Y	Y	Y	$9.77	36%	$0.00	$9.77
	Incremental T&D and DSP Costs	Y	Y	Y	$17.13	64%	$17.13	$0.00
	TOTAL COSTS	$26.9	$26.9	$26.9	$26.9		$17.1	$9.8

VVO/CVR Benefit Cost Analysis Detail

VVO/CVR Benefits ($MM)	Time Period	FY19	FY20	FY21	FY22-34	Real ($MM)	NPV ($MM)
Avoided Generation Capacity Costs	FY20-34	$0.00	$0.00	$0.19	$22.38	$22.58	$10.91
Avoided LBMP	FY19-22	$0.00	$0.26	$0.93	$48.87	$50.06	$24.11
Net Avoided CO2		$0.00	$0.15	$0.55	$20.62	$21.32	$10.58
Total Benefits	FY19-34	$0.00	$0.41	$1.67	$91.87	$93.96	$45.60

VVO/CVR Costs ($MM)	Time Period	FY19	FY20	FY21	FY22-34	Real ($MM)	NPV ($MM)
Cost of Removal	FY19-22	$0.10	$0.20	$0.29	$0.35	$0.95	
Capital Expenditures	FY19-22	$2.55	$5.17	$7.27	$8.37	$23.36	
Incremental T&D and DSP		$2.65	$5.37	$7.56	$8.72	$24.31	$17.13
Ongoing License Fees & Communications O&M	FY19-34	$0.09	$0.30	$0.57	$13.62	$14.58	
Operating Expenditures	FY19-22	$0.52	$1.03	$1.79	$1.65	$4.99	
Program Admin Costs		$0.61	$1.34	$2.36	$15.27	$19.57	$9.77
Total Costs	FY19-34	$3.26	$6.71	$9.92	$23.99	$43.88	$26.89

Note: Fiscal Year ends March 31

Category	Item	NPV ($MM)
Benefits	Total	$3.02
	SCT	$3.02
	UCT	$3.02
	RIM	$3.02

Costs	Total	$1.0
	CapEx split	$0.1
	O&M split	$1.0
	SCT	$1.0
	UCT	$1.0
	RIM	$1.0

Cost-Effectiveness Tests	SCT Ratio	2.9
	UCT Ratio	2.9
	RIM Ratio	2.9

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
	Net Non-Energy Benefits (Customer Acquisition Costs)	Y	Y	Y	$3.02	100%		
	TOTAL BENEFITS	$3.0	$3.0	$3.0	$3.02			
Cost	Program Administration Costs	Y	Y	Y	$0.98	95%	$0.00	$0.98
	Incremental T&D and DSP Costs	Y	Y	Y	$0.05	5%	$0.05	$0.00
	TOTAL COSTS	$1.0	$1.0	$1.0	$1.03		$0.1	$1.0

Residential Solar Provider Marketplace Benefit Cost Analysis Detail

Solar Marketplace Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Reduced Customer Acquisition Costs for Solar Provic	FY19-22		$0.86	$0.94	$0.99	$1.03	$3.82	$3.02
Total Benefits	FY19-22		$0.86	$0.94	$0.99	$1.03	$3.82	$3.02

Solar Marketplace Costs ($MM)	Time Period	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Incremental T&D and DSP Costs	FY19	$0.05	$0.00	$0.00	$0.00	$0.05	$0.05
Program Administration Costs	FY19-22	$0.38	$0.35	$0.25	$0.23	$1.21	$0.98
Total Costs	FY19-22	$0.43	$0.35	$0.25	$0.23	$1.27	$1.03

Note: Fiscal Year ends March 31

Niagara Mohawk Power Corporation d/b/a National Grid
E-commerce Portal Benefit Cost Analysis Summary
($MM)

Category	Item	NPV ($MM)
Benefits	Total	$0.22
	SCT	$0.22
	UCT	$0.22
	RIM	$0.22

Costs	Total	$0.14
	CapEx split	$0.05
	O&M split	$0.09
	SCT	$0.14
	UCT	$0.14
	RIM	$0.14

Cost-Effectiveness Tests	SCT Ratio	1.53
	UCT Ratio	1.53
	RIM Ratio	1.53

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
Benefit	Avoided O&M	Y	Y	Y	$0.22	100%		
	TOTAL BENEFITS	$0.2	$0.2	$0.2	$0.2			
Cost	Program Administration Costs	Y	Y	Y	$0.14	100%	$0.05	$0.09
	TOTAL COSTS	$0.1	$0.1	$0.1	$0.1		$0.1	$0.1

E-commerce Portal Benefit Cost Analysis Detail

E-commerce Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Avoided O&M	FY18-22	$0.05	$0.05	$0.05	$0.05	$0.06	$0.26	$0.22
Total	FY18-22	$0.05	$0.05	$0.05	$0.05	$0.06	$0.26	$0.22

E-commerce Costs ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Program Administration Costs	FY18	$0.15	$0.00	$0.00	$0.00	$0.00	$0.15	$0.14
Total	FY18	$0.15	$0.00	$0.00	$0.00	$0.00	$0.15	$0.14

Note: Fiscal Year ends March 31

Niagara Mohawk Power Corporation d/b/a National Grid
Demand Response Management System (DRMS) Benefit Cost Analysis Summary
($MM)

Category	Item	NPV ($MM)
Benefits	Total	$7.1
	SCT	$7.1
	UCT	$7.1
	RIM	$7.1

Costs	Total	$4.3
	CapEx split	$3.9
	O&M split	$0.4
	SCT	$4.3
	UCT	$4.3
	RIM	$4.3

Cost-Effectiveness Tests	SCT Ratio	1.7
	UCT Ratio	1.7
	RIM Ratio	1.7

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
Benefit	AGCC	Y	Y	Y	$7.13	100%		
	TOTAL BENEFITS	$7.1	$7.1	$7.1	$7.13			
Cost	Program Administration Costs	Y	Y	Y	$0.39	9%		$0.39
	Incremental T&D and DSP Costs	Y	Y	Y	$3.93	91%	$3.93	
	TOTAL COSTS	$4.3	$4.3	$4.3	$4.32		$3.9	$0.4

Demand Response Management System (DRMS) Benefit Cost Analysis Detail

DRMS Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Avoided Generation Capacity Costs	FY18-21	$0.95	$1.23	$3.19	$3.32		$8.70	$7.13
Total Benefits	FY18-21	$0.95	$1.23	$3.19	$3.32	$0.00	$8.70	$7.13

DRMS Costs ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22	Real ($MM)	NPV ($MM)
Program Administration Costs	FY18-21	$0.40	$0.01	$0.01	$0.00		$0.42	$0.39
Incremental T&D and DSP Costs	FY18-21	$3.43	$0.00	$0.00	$1.20		$4.63	$3.93
Total Costs	FY18-21	$3.83	$0.01	$0.01	$1.20	$0.00	$5.05	$4.32

Note: Fiscal Year ends March 31

Niagara Mohawk Power Corporation d/b/a National Grid
Energy Storage Benefit Cost Analysis Summary
($MM)

Category	Item	NPV ($MM)
Benefits	Total	$9.6
	SCT	$5.2
	UCT	$5.2
	RIM	$9.6

Costs	Total	$8.4
	CapEx split	$8.1
	O&M split	$0.2
	SCT	$8.4
	UCT	$8.4
	RIM	$8.4

Cost-Effectiveness Tests	SCT Ratio	0.6
	UCT Ratio	0.6
	RIM Ratio	1.2

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total		
Benefit	Avoided Generation Capacity Costs	Y	Y	Y	$2.66	28%		
	Avoided LBMP	Y	Y	Y	$0.00	0%		
	Avoided Distribution Capacity Infrastructure	Y	Y	Y	$2.55	26%		
	Net Avoided CO2	Y			$0.00	0%		
	Revenue from Wholesale Market Particiaption			Y	$4.43	46%		
	TOTAL BENEFITS	$5.2	$5.2	$9.6	$9.6			
							CapEx (NPV)	O&M (NPV)
Cost	Program Administration Costs	Y	Y	Y	$0.25	3%		$0.25
	Incremental T&D and DSP Costs	Y	Y	Y	$8.12	97%	$8.12	
	TOTAL COSTS	$8.4	$8.4	$8.4	$8.4		$8.1	$0.2

Energy Storage Benefit Cost Analysis Detail

Energy Storage Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22-29	Real ($MM)	NPV ($MM)
Avoided Generation Capacity Costs	FY20-29		$0.00	$0.43	$0.43	$3.43	$4.29	$2.66
Avoided LBMP	FY20-29		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Avoided Distribution Capacity Infrastructure*	FY20-35		$0.00	$0.00	$0.00	$2.55		$2.55
Net Avoided CO2	FY20-29		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Revenue from Wholesale Market Participation	FY20-29		$0.00	$0.69	$0.70	$5.78	$7.17	$4.43
Total Benefits	FY20-29		$0.00	$1.12	$1.13	$11.76	$11.46	$9.64

Energy Storage Costs ($MM)	Time Period	FY19	FY20	FY21	FY22-29	Real ($MM)	NPV ($MM)
Program Administration Costs	FY19-29	$0.00	$0.04	$0.04	$0.32	$0.40	$0.25
Incremental T&D and DSP Costs	FY19	$9.27	$0.00	$0.00	$0.00	$9.27	$8.12
Total Costs	FY19-29	$9.27	$0.04	$0.04	$0.32	$9.67	$8.37

*Value of deferring T&D investment from 2020 to 2035
Note: Fiscal Year ends March 31

Category	Item	NPV ($MM)
Benefits	Total	$15.0
	SCT	$10.0
	UCT	$0.4
	RIM	$5.4

Costs	Total	$9.0
	CapEx split	$0.0
	O&M split	$2.8
	SCT	$9.0
	UCT	$5.3
	RIM	$5.3

Cost-Effectiveness Tests	SCT Ratio	1.1
	UCT Ratio	0.1
	RIM Ratio	1.0

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
Benefit	Avoided Generation Capacity Costs	Y	Y	Y	$0.38	3%		
	Net Avoided CO2	Y			$1.17	8%		
	Net Avoided SO2 and NOx	Y			$0.00	0%		
	Increased Utility Revenue			Y	$4.99	33%		
	Avoided Non-Electric Fuel Cost	Y			$8.44	56%		
	TOTAL BENEFITS	$10.0	$0.4	$5.4	$15.00			
Cost	Program Administration Costs	Y	Y	Y	$2.82	31%		$2.82
	Increased LBMP	Y	Y	Y	$2.43	27%		
	Participant DER Cost	Y			$3.77	42%		
	TOTAL COSTS	$9.0	$5.3	$5.3	$9.02		$0.0	$2.8

Heat Pump Benefit Cost Analysis Detail

Heat Pump Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22-35	Real ($MM)	NPV ($MM)
Avoided Generation Capacity Costs	FY18-35	$0.00	$0.01	$0.02	$0.04	$0.63	$0.70	$0.38
Net Avoided CO2	FY18-35	$0.01	$0.04	$0.08	$0.10	$1.88	$2.12	$1.17
Net Avoided SO2 and NOx	FY18-35	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.00
Increased Utility Revenue	FY18-35	$0.08	$0.24	$0.50	$0.51	$7.19	$8.52	$4.99
Avoided Non-Electric Fuel Cost	FY18-35	$0.11	$0.36	$0.77	$0.80	$12.70	$14.73	$8.44
Total Benefits	FY18-35	$0.20	$0.64	$1.37	$1.46	$22.41	$26.07	$15.00

Heat Pump Costs ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22-30	Real ($MM)	NPV ($MM)
Program Administration Costs	FY18-20	$0.73	$1.02	$1.30	$0.00	$0.00	$3.05	$2.82
Increased LBMP	FY18-35	$0.03	$0.10	$0.20	$0.21	$3.77	$4.31	$2.43
Participant DER Cost	FY18-20	$0.66	$1.36	$2.09	$0.00	$0.00	$4.12	$3.77
Total Costs	FY18-35	$1.42	$2.47	$3.59	$0.21	$3.77	$11.47	$9.02

Note: Fiscal Year ends March 31

Category	Item	NPV ($MM)
Benefits	Total	$37.6
	SCT	$22.8
	UCT	$0.0
	RIM	$14.8

Costs	Total	$26.8
	CapEx split	$12.5
	O&M split	$7.3
	SCT	$26.8
	UCT	$26.8
	RIM	$26.8

Cost-Effectiveness Tests	SCT Ratio	0.8
	UCT Ratio	0.0
	RIM Ratio	0.6

Category	Benefit / Cost	SCT	UCT	RIM	NPV ($MM)	% of total	CapEx (NPV)	O&M (NPV)
Benefit	Net Avoided CO2	Y			$5.62	15%		
	Net Avoided CO2 (Non-Attributable EV's)	Y			$0.19	1%		
	Net Avoided SO2 and NOx	Y			$0.00	0%		
	Net Avoided SO2 and Nox (Non-Attributable EV's)	Y			$0.00	0%		
	Increased Utility Revenue			Y	$14.34	38%		
	Increased Utility Revenue (Non-Attributable EV's)			Y	$0.46	1%		
	Avoided Non-Electric Fuel Cost	Y			$17.00	45%		
	TOTAL BENEFITS	$22.8	$0.0	$14.8	$ 37.60			
Cost	Program Administration Costs	Y	Y	Y	$7.26	27%	-	$7.26
	Incremental T&D and DSP Costs	Y	Y	Y	$12.52	47%	$12.52	-
	Participant DER Cost	Y			$0.00	0%		
	Increased Generation Capacity Costs	Y	Y	Y	$6.85	26%		
	Increased LBMP	Y	Y	Y	$0.21	1%		
	Increased LBMP (Non-Attributable EV's)	Y	Y	Y	$0.00	0%		
	TOTAL COSTS	$26.8	$26.8	$26.8	$26.84		$12.5	$7.3

Electric Vehicles Benefit Cost Analysis Detail

Electric Vehicles Benefits ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22-31	Real ($MM)	NPV ($MM)
Net Avoided CO2	FY19-31	$0.00	$0.00	$0.15	$0.39	$9.97	$10.51	$5.62
Net Avoided CO2 (Non-Attributable EV's)	FY19-31	$0.00	$0.01	$0.02	$0.02	$0.28	$0.33	$0.19
Net Avoided SO2 and NOx	FY19-31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Avoided SO2 and Nox (Non-Attributable EV's)	FY19-31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Increased Utility Revenue	FY19-31	$0.00	$0.00	$0.49	$1.28	$23.88	$25.65	$14.34
Increased Utility Revenue (Non-Attributable EV's)	FY19-31	$0.00	$0.03	$0.06	$0.06	$0.61	$0.76	$0.46
Avoided Non-Electric Fuel Cost	FY19-31	$0.00	$0.00	$0.65	$1.66	$27.71	$30.02	$17.00
Total Benefits	FY19-31	$0.00	$0.04	$1.37	$3.42	$62.46	$67.28	$37.60

Electric Vehicles Costs ($MM)	Time Period	FY18	FY19	FY20	FY21	FY22-31	Real ($MM)	NPV ($MM)
Program Administration Costs	FY18-21	$0.45	$1.77	$2.87	$3.70	$0.14	$8.93	$7.26
Incremental T&D and DSP Costs	FY18-25	$0.00	$1.07	$4.23	$9.01	$1.86	$16.17	$12.52
Increased Generation Capacity Costs	FY19-31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Increased LBMP	FY19-31	$0.00	$0.00	$0.19	$0.51	$11.81	$12.51	$6.85
Increased LBMP (Non-Attributable EV's)	FY19-31	$0.00	$0.01	$0.02	$0.03	$0.30	$0.36	$0.21
Total	FY18-31	$0.45	$2.84	$7.32	$13.24	$14.11	$37.97	$26.84

Note: Fiscal Year ends March 31

Exhibit __ (ECP-5CU)

Company's proposed EAMs

Exhibit ___ (ECP-5) Summary of EAM Basis Points

EAM	Achievement Targets	Annual Basis Point Allocations 2017	2018	2019	2020
System Efficiency		**40**	**45**	**45**	**45**
Annual Peak Reduction	Minimum	9	9	9	9
	Mid-Point	14	14	14	14
	Maximum	30	30	30	30
Substation Load Factor	Minimum	N/A	1	1	1
	Mid-Point		2.5	2.5	2.5
	Maximum		5	5	5
DER Utilization	Minimum	0	0	0.5	0.5
	Mid-Point	4	4	4	4
	Maximum	10	10	10	10
Energy Efficiency		**30**	**30**	**30**	**30**
Incremental Energy Efficiency	Minimum	0	0	0	0
	Mid-Point	4	4	3	2.5
	Maximum	10	10	9	7
Energy Intensity (Residential)	Minimum	2	2	3	4
	Mid-Point	3	3	4.5	5
	Maximum	8.5	8.5	9	10
Energy Intensity (Commercial)	Minimum	2	2	3	4
	Mid-Point	3	3	4.5	5
	Maximum	8.5	8.5	9	10
Energy Intensity (Low-Income)	Minimum	0.5	1	1	1
	Mid-Point	0.75	1.5	1.5	1.5
	Maximum	3	3	3	3
Interconnection			**5**	**5**	**5**
Developer Satisfaction Survey	Minimum	N/A	1	1	1
	Mid-Point		2.5	2.5	2.5
	Maximum		5	5	5
Customer Engagement			**3.34**	**10**	**10**
DR Retention	Minimum	N/A	0	0	0
	Mid-Point		1.0	1.0	1.0
	Maximum		2.5	2.5	2.5
Customer Participation	Minimum	N/A	0	0	0
	Mid-Point		0.42	1.0	1.0
	Maximum		0.83	2.5	2.5
Transactional Conversion Rate	Minimum	N/A		0	0
	Mid-Point			1	1
	Maximum			2.5	2.5
Survey	Minimum	N/A		0	0
	Mid-Point			1	1
	Maximum			2.5	2.5
Total Basis Points	**Minimum**	**13.5**	**16**	**18.5**	**20.5**
	Mid-Point	**28.8**	**35.9**	**40.5**	**41**
	Maximum	**70**	**83.3**	**90**	**90**

Note: numbers may not add due to rounding.

Exhibit ___ (ECP-5) Summary of EAM Targets

EAM	Achievement Targets	Annual Targets 2017	2018	2019	2020
System Efficiency					
Annual Peak Reduction (MW)	Minimum	159	155	167	193
	Mid-Point	235	271	330	394
	Maximum	393	469	566	669
Substation Load Factor	Minimum	N/A	1%	1%	1%
	Mid-Point		2%	2%	2%
	Maximum		3%	3%	3%
DER Utilization (MWh)	Minimum	95,448	148,447	154,408	160,940
	Mid-Point	167,497	210,958	215,680	246,134
	Maximum	239,407	301,386	311,697	357,377
Energy Efficiency					
Incremental Energy Efficiency (MWh)	Minimum	230,705	281,240	281,240	281,240
	Mid-Point	288,381	348,904	348,904	348,904
	Maximum	354,931	426,711	426,711	426,711
Energy Intensity (Residential)	Minimum	0.84%	0.85%	0.86%	0.86%
	Mid-Point	1.29%	0.98%	0.99%	1.00%
	Maximum	1.75%	1.32%	1.34%	1.35%
Energy Intensity (Commercial)	Minimum	0.88%	0.89%	0.90%	0.91%
	Mid-Point	1.09%	1.10%	1.11%	1.12%
	Maximum	1.36%	1.38%	1.40%	1.42%
Energy Intensity (Low-Income)	Minimum	0.02%	0.09%	0.09%	0.09%
	Mid-Point	0.10%	0.53%	0.53%	0.53%
	Maximum	0.53%	1.06%	1.25%	1.27%
Interconnection					
Developer Satisfaction Survey	Maximum	N/A	TBD		
Customer Engagement					
DR Retention (Residential & Small Business)	Minimum	N/A	85%	88%	89%
	Mid-Point		93%	96%	97%
	Maximum		95%	98%	99%
DR Retention (C&I)	Minimum	N/A	92%	91%	91%
	Mid-Point		95%	94%	94%
	Maximum		97%	97%	97%
Customer Participation (Residential)	Minimum	N/A	3,450	TBD	
	Mid-Point		5,000		
	Maximum		6,150		
Customer Participation (C&I)	Minimum	N/A	15	TBD	
	Mid-Point		30		
	Maximum		45		
Transactional Conversion Rate	Maximum	N/A		TBD	
Survey	Maximum	N/A		TBD	

Exhibit ___ (ECP-5) Non-Weather Normalized Peak Reduction
Coincident/Non-Coincident Peak

Niagara Mohawk Non-Weather Normalized Peak (MW)											
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average
Coincident Peak	6365	6536	6437	6771	6934	6928	7017	5843	6556	6809	
Non-Coincident Peak	6751	6536	6437	6943	7149	6931	7077	6428	6643	6809	
Ratio	94%	100%	100%	98%	97%	100%	99%	91%	99%	100%	98%

Exhibit ___ (ECP-5) Targeted Substation Load Factor
Weighted Average Load Factor of Seven Substations

Substation	Station#	Transformer ID	2017 SN[1]	2016 Peak (MW)	2016 Annual Load (MWh)	2016 Load Factor
Sorrell Hill	269	1	99.3%	26.87	107,823	45.7%
Southwood	244	1	98.1%	20.36	83,475	46.7%
Duguid	265	1	97.7%	31.29	119,862	43.6%
MCCLELLAN ST.	304	1	94.5%	12.52	60,977	55.4%
YAHNUNDASIS	646	3	93.6%	31.32	131,264	47.7%
Swaggertown	364	1	93.2%	20.10	70,453	39.9%
Fly Road	261	1	92.6%	27.79	145,551	59.6%
Weighted average total						**48.1%**

[1] Summer Normal ("SN") is a measure of the substation peak divided by the rated normal capacity of the substation.

Exhibit ___ (ECP-5) Residential Energy Intensity Targets

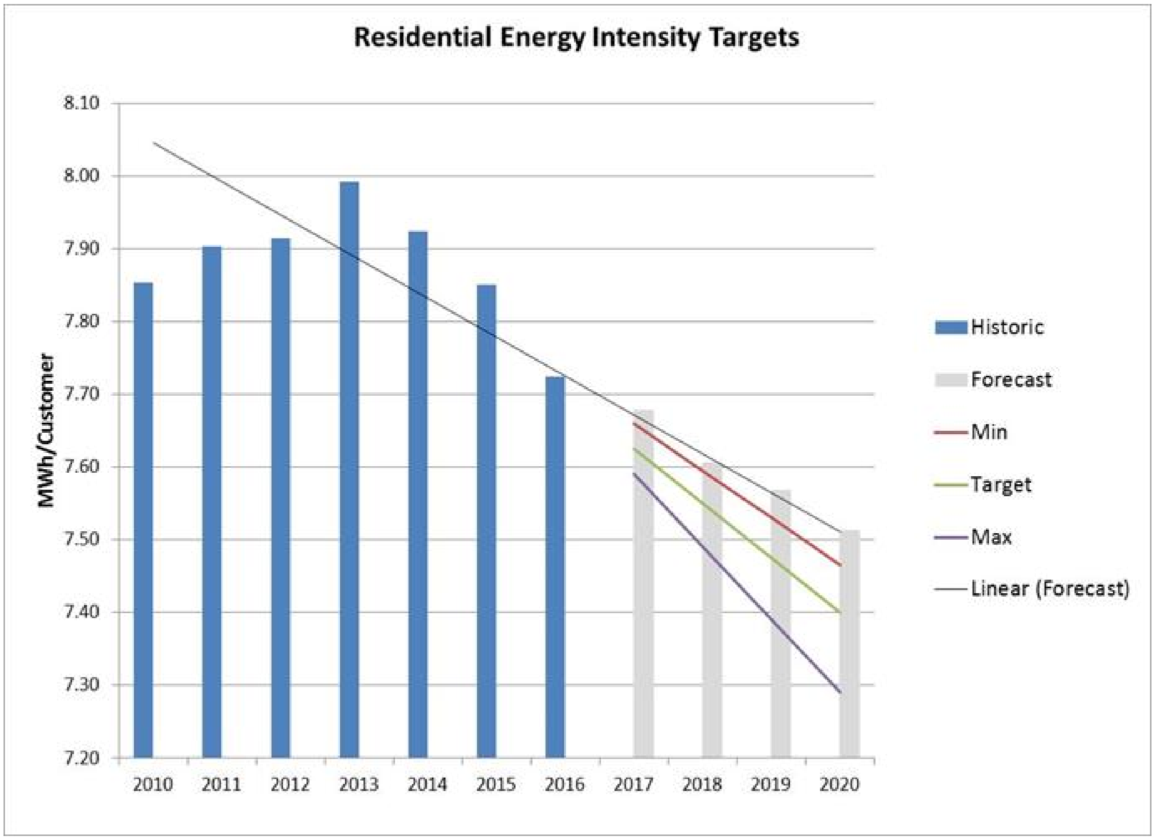


Exhibit ___ (ECP-5) Commercial Energy Intensity Targets

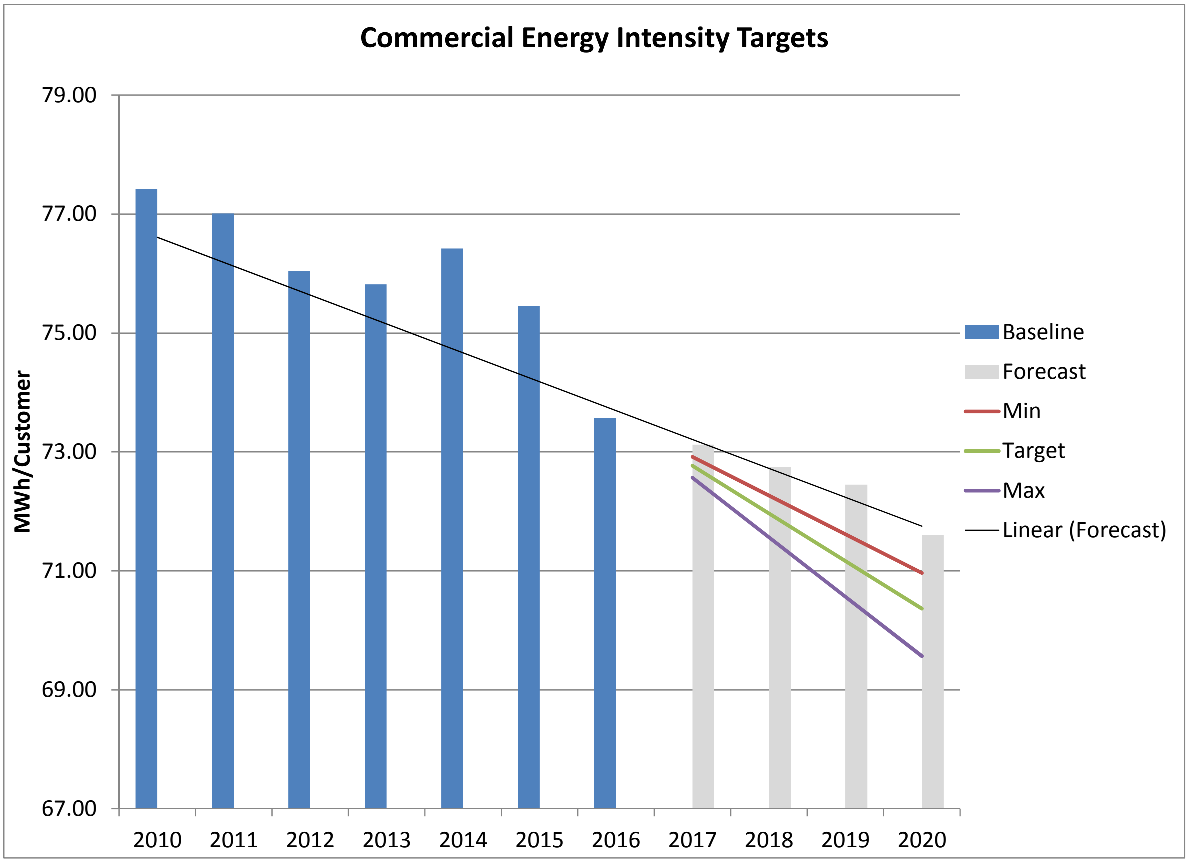


Exhibit ___ (ECP-5) Low-Income Energy Intensity Targets

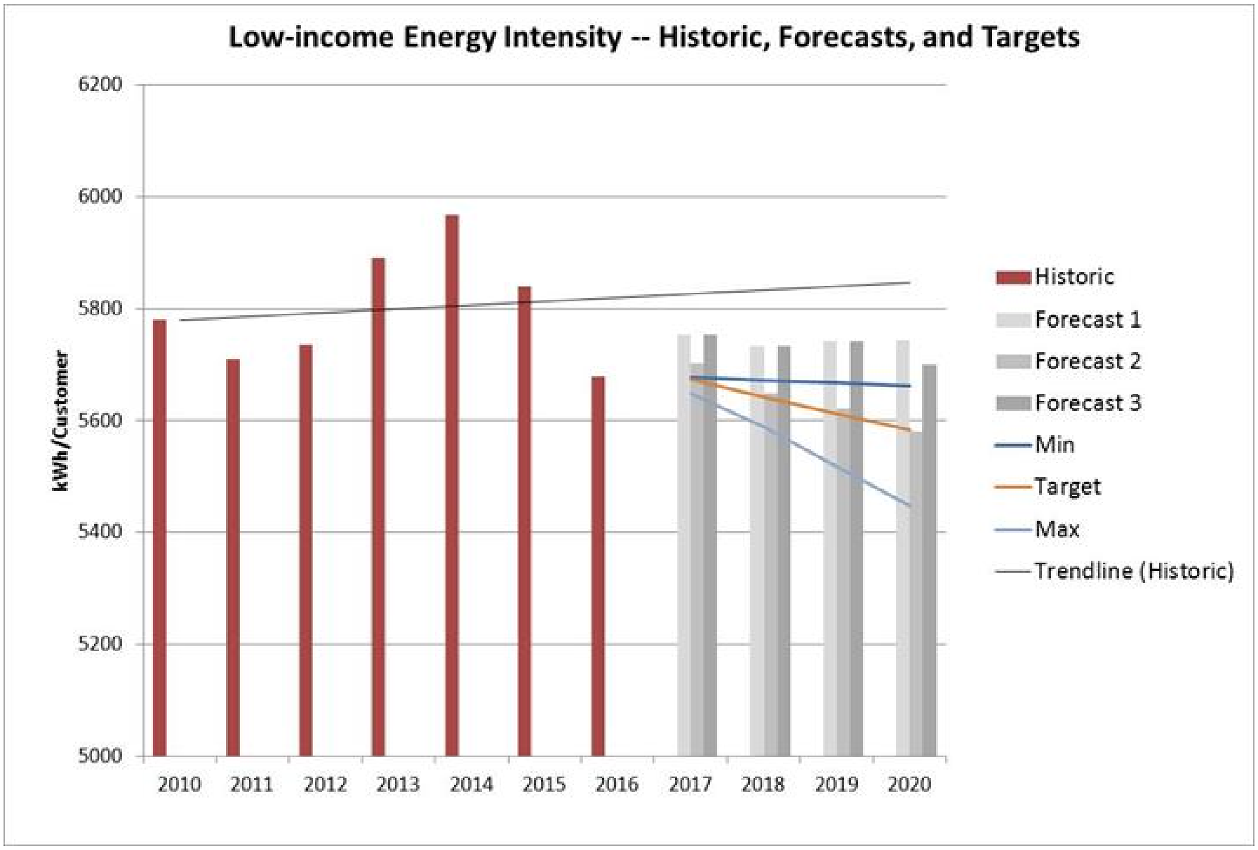


Exhibit ___ (ECP-5) Summary of Electric EAM Net Benefits

Summary of EAM Net Benefits	Portfolio Net Benefits	4 year EAM Incentive Value	Savings to Customers	EAM Incentive	Savings to Customers
	NPV	NPV	NPV	%	%
Minimum	$156.5	$24.4	$132.1	16%	84%
Mid-Point Target	$303.1	$52.0	$251.1	17%	83%
Maximum	$492.8	$118.5	$374.3	24%	76%

		Benefits		
	Total (NPV $m)	Minimum	Target	Maximum
Benefits	Avoided MW	$55.3	$100.6	$171.4
	Avoided Local MW	$0.9	$1.8	$2.7
	Avoided MWh	$219.6	$285.3	$363.4
	Avoided CO2	$127.4	$165.9	$211.8
	TOTAL BENEFITS	**$403.2**	**$553.6**	**$749.3**

		Costs		
	Total (NPV $m)	Minimum	Target	Maximum
Costs	Program Administration Costs	$11.5	$11.5	$11.5
	Incremental T&D and DSP Costs	$29.2	$29.2	$29.2
	Energy Efficiency Program Admin	$192.6	$192.6	$192.6
	DR Performance Payments	$13.3	$17.1	$23.1
	TOTAL COSTS	**$246.7**	**$250.5**	**$256.5**

Net Benefits		**$156.5**	**$303.1**	**$492.8**

Exhibit ___ (ECP-5) Summary of Gas Efficiency EAM Net Benefits

	Annual Net Benefits ($ Millions)				Average Annual Incentive Value ($Millions)	Average Annual Share of Net Benefits to Customers
	2017	2018	2019	2020		
Minimum	5.0	9.9	9.9	9.9	0	100%
Mid-Point Target	7.6	13.1	13.1	13.1	0.4	86%
Maximum	10.8	17.1	17.1	17.1	1.0	85%

Exhibit __ (ECP-6CU)

Information Requests

Date of Request: May 8, 2017 Request No. DPS-022 MZS-3
Due Date: May 18, 2017 NMPC Req. No. NM-409

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Mary Ann Sorrentino

TO: National Grid, Electric Customer Panel

SUBJECT: ***ANNUAL PEAK REDUCTION***

Request:

With reference to Exhibit ECP-5, Schedule 3, Page 1 of 1, provide:

a) The date and time of the coincident and non-coincident peaks shown in the chart;
b) The chart on a weather normalized basis; and
c) The weather normalization calculations.

Response:

In preparing this response, the Company discovered an error in the methodology used to calculate the normalized system-peak baseline of 6,737 MW set forth on page 46, line 1, of the Electric Customer Panel's testimony ("Prior Methodology"). Specifically, the Prior Methodology does not accurately produce Company level weather-adjusted values when the days of the zonal peaks (the subzones within the Company service territory previously used to estimate the Company total) occurs on days different than the peak day of the Company. The correct value for the Company's 2016 weather normalized system-peak baseline should be 6,846 MW, as shown in the response to part b) below.

The Prior Methodology first calculated weather-normal values on the day of each zone's own peak to establish the relationship between that zone's actual peak and its weather-adjusted value. The Company then multiplied the weather-adjusted value by a coincidence factor value based on that zone's peak to Company peak actual values. This was done for each zone and then aggregated to arrive at the normalized system-peak baseline of 6,737 MW set forth in the Electric Customer Panel's testimony. However, in preparing the response, the Company discovered that the Prior Methodology does not accurately capture the correct Company weather normalized value in cases where a zone peaked on a different day than the Company, and that zone's peak day weather-adjustment moves in the opposite direction then that on the Company day. An example of this occurred in the baseline year, 2016, where Zone F peaked on Friday, August 12th and the Company peaked on Thursday, August 11th. The weather on Thursday was slightly lower than normal (an actual weighted temperature-humidity variable ("WTHI") of 80.3 vs. a normal of 80.5). This infers that an upward weather adjustment should be made. The weather on Friday, which impacted Zone F had an actual WTHI of 81.2, higher than normal, inferring a downward adjustment for loads on that day. While this downward adjustment is correctly made, looking at that zone in isolation when transferring to the Company peak can cause incorrect results. The Prior Methodology did exactly this by carrying the downward Zone F adjustment into the Company calculation for Thursday. This caused the weather normalized Company value to decrease when it should have increased. This same issue could cause inaccuracies when determining Company peaks coincident with the NYISO when those days are not the same.

Based on the foregoing, the Company is correcting for this methodology error, as discussed below, and will make the appropriate correction in its Corrections and Updates filing. Please note that the weather normalization process described below is the updated process the Company is proposing to utilize to weather normalize the peaks for the purpose of measuring the Peak Reduction EAM results.

a) The date and time of the coincident and non-coincident peaks are:

Company Peak Times

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Date	2-Aug	9-Jun	17-Aug	8-Jul	21-Jul	17-Jul	19-Jul	1-Jul	8-Sep	11-Aug
Hour Ending	16	17	16	16	17	16	14	16	15	17

NYISO Peak Times

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Date	8-Aug	9-Jun	17-Aug	6-Jul	22-Jul	17-Jul	19-Jul	2-Sep	29-Jul	11-Aug
Hour Ending	17	17	16	17	16	17	17	16	17	17

b) The chart for coincidence and non-coincidence on a weather normalized basis is:

Niagara Mohawk Weather-Normalized Peaks (MW)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Coincident Peak	6,664	6,659	6,607	6,652	6,702	6,694	6,726	6,451	6,576	6,766
Non-Coincident Peak *	6,733	6,735	6,683	6,721	6,702	6,782	6,864	6,749	6,777	6,846
Ratio	99%	99%	99%	99%	100%	99%	98%	96%	97%	99%

Non-coincident, or Company peak days, and the weather normalized values of those peaks are on the days of the Company's "actual" loads. They are not associated with weather normalized values for any other days during the entire summer period.

c) The weather normalization calculations are performed as follows.

The weather normalization process was calculated for each year using regression analysis to establish a relationship between load and weather and other relevant variables, as appropriate. The Company used a daily model with the load on each of the summer days as the dependent variable and a WTHI as the primary independent variable. The WTHI captures both the impacts of temperature and humidity on loads and was specified as a multi-day variable to capture the impacts of heat waves. The Company also used the actual weather on each day to specify the regression analysis and establish the model coefficients used to make the weather adjustments. The days of the three summer months of June, July and August were used each year. These days most closely capture the typical peak producing months. The exception was in 2014 and in 2015 when the NYISO or the Company peaked in September. The weather inputs were from relevant National Weather Service stations in the Company's service territory. These included Albany, Syracuse, Buffalo, Watertown, Utica, Rochester and Massena. Weather station inputs for each zone were weighted by load in each area.

Other variables tested and used in the model, as applicable, were:

- Friday, Saturday and Sunday categorical day indicators to capture typically lower load on those days versus other weekdays;
- July 4th and/or the days ahead or after this holiday depending on when it was celebrated each year;
- A monthly "September" categorical month indicator for any years where the Company (in 2015) or NYISO peak (in 2014) was in the non-typical lower load month of September instead of the more frequent peak months of June, July, or August;
- An annual indicator. While the regression was performed individually and specifically for each year, to ensure that sufficient observations were included to capture a fuller range of temperature – humidity impacts on load, most models included a second year in addition to the current year being modeled. This "annual" indicator was included, if statistically significant, to capture any year-over-year non-weather related changes such as economic growth;
- A "cool summer" categorical indicator for years 2014 and 2015 where the summer season was unusually cool prior to the peak day. The concept here is that in the absence of any extreme "hot" weather prior to the peak, people may not have installed all of their room ACs and other such cooling equipment yet (this has not been studied directly herein but bears out as a variable on a statistical basis).

Generally speaking, the actual loads are weather-normalized by taking the difference between actual weather and normal weather, multiplying that by the regression weather coefficients and adding those to the actual load. The Company also included additional categorical variables for years when those variables were also applicable in the final results.

This process is repeated separately for each year to weather normalize Company peaks. This process is again repeated to determine the load at the time of the NYISO peaks. For the weather normalization process for the NYISO days, the Company used a separate 20 year weather normal value for WTHI based on the historical days coincident with the NYISO.

The "normal" values for WTHI for the Company peak and also for coincidence with the NYISO are:

	WTHI
Company:	80.5
NYISO:	80.0

The units for the WTHI are degrees. It is appropriate for the 20-year normal for the days coincident with the NYISO to be lower than the Company's normal because for most years the Company peak coincident with the NYSIO peak would have occurred during the same or cooler weather than that on the actual day of the Company peak.

Name of Respondent:
Joe Gredder

Date of Reply:
May 18, 2017

Date of Request: May 8, 2017 Request No. DPS-025 MZS-6
Due Date: May 18, 2017 NMPC Req. No. NM-412

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Mary Ann Sorrentino

TO: National Grid, Electric Customer Panel

SUBJECT: ***ANNUAL PEAK REDUCTION***

Request:
With reference to page 46, lines 6-8 of the Panel's Pre-Filed Direct Testimony and the accompanying Exhibit__(ECP-5), Schedule 3, Page 1 of 1:

a) Explain how the 2016 peak was weather normalized;
b) If the 2016 peak was not normalized using the prior 20 annual peak days, then provide the 2016 peak using this normalization process; and
c) Provide the coincident and non-coincident peaks listed on the referenced Exhibit using this proposed normalization process.

Response:

Please see the Company's response to DPS-022 for the correction the Company is making to the 2016 weather-normalized system peak baseline of 6,737 MW, as set forth on page 46, line 1 of the Electric Customer Panel's testimony. The correct value for the Company's 2016 weather normalized system-peak baseline should be 6,846 MW, as shown in the response to part b) of DPS-022. The Company will make this correction in its Corrections and Updates filing.

a) The response to DPS-022, item (c) explains the process to weather normalize the 2016 peak. As discussed in that response, this process has been corrected from the methodology originally used by the Company to weather normalize system peak and produces different values. The resulting regression equation for 2016 is:

load (actual) = 173.7 (WTHI) + -79.1 (Fri) + -598.1 (Sat) + -560.1 (Sun) +
-874.9 (July 4, 2013) + -444.2 (July 5, 2013) + - 538.7 (July 4, 2016) - int

where:

- WTHI (weighted temperature-humidity variable) is the weighted three-day temperature-humidity index each day.
- Fri/Sat/Sun are categorical indicators of 0 or 1 for those days.
- July 4, 2013, July 5, 2013 and July 4, 2016 are categorical indicators of 0 or 1 for those holiday days.
- int: intercept of model equation (-7,324).

The input data set for this model were the daily loads and weather for the months of June, July and August for the years 2016 and 2013. Year 2013 was added to the dataset because that was the most recent extreme weather day and thus adds data points at the higher end of the weather scale.

b) The normalization uses the weather from the prior 20 peak days.

c) The table included in the response to DPS-22, item (a) provides the coincident and non-coincident weather normalized peaks.

<u>Name of Respondent</u>:	<u>Date of Reply</u>:
Joe Gredder	May 18, 2017

Date of Request: May 24, 2017
Due Date: June 5, 2017

Request No. DPS-131 JT-1
NMPC Req. No. NM-567

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Jeff Tengeler

TO: National Grid, Electric Customer Panel

SUBJECT: ***ENERGY INTENSITY EAMS***

Request:

In these interrogatories, all requests for data, work papers, or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

1) For the period January 2010 through and including the most recent data available:

   a. Provide the historic actual number of customers and monthly kWh of usage for all service classifications and sub classifications.

   b. Provide the historic weather data used to normalize energy (heating and cooling degree days).

2) With reference to Exhibit__(ECP-5), Schedule 5, 6, and 7:

   a. Provide the work paper(s) used to develop the graphs and proposed targets.

   b. Explain which service classifications are included in the Residential, Commercial, and Low-Income Energy Intensity groupings.

Response:

1)
   a. Please see Attachment 1 for monthly customer counts and monthly kWh usage by service classification. The SC-1 service class includes SC-1C customer counts and usages.

b. Please refer to the response to DPS-PF-77 for the historic weather data used to normalize energy (heating and cooling degree days).

2) With reference to Exhibit__(ECP-5), Schedule 5, 6, and 7:

a. Please see Attachment 2 for the spreadsheet used to develop the proposed Energy Intensity targets and graphs.

When preparing this response, the Company realized that the 2017-2020 kWh sales forecast used for Energy Intensity EAM development was based on an outdated Company forecast. Attachment 3 includes updated Energy Intensity forecasts and graphs based on the sales forecast utilized for the rate case filing, with changes highlighted in yellow. The Company will also update the Energy Intensity targets in the Corrections and Updates filing.

b. The residential service classification includes customers with a parent service classification of SC-1 and SC-1C. The commercial service classification includes customers with a parent service classification of SC-2ND and SC-2D, and a portion of the customers with a parent service classification of SC-3and SC-3A. This determination of residential or commercial is based on the revenue code assigned to the account in the billing system. National Grid does not currently track low income as a separate service classification, but for the purpose of the Energy Intensity metric, the Company defined low income as all residential customers whose accounts were tagged with a c4 rider in the billing system, indicating the customer received Home Energy Assistance Program ("HEAP") payments at any point during the year. This includes service classifications SC-1 Non Heat; SC-1C Non Heat; SC-1 Heat; SC-1C Heat; SC-1 T&D Non Heat; SC-1 T&D Heat; SC-1C T&D Non Heat; SC-1C T&D Heat.

<u>Name of Respondent</u>:	<u>Date of Reply</u>:
Courtney Eichhorst	June 5, 2017
Meghan McGuinness	

MONTHLY
Rate Class
Customer Count

YEAR	MONTH	SC1	SC2ND	SC2D	SC3	SC3A	SC4	SC7	SC11_12	SL	TOTAL
2010	1	1,451,805	108,490	48,437	4,456	204	75	43	113	12,589	1,626,212
2010	2	1,452,971	108,492	48,358	4,440	207	76	42	111	12,579	1,627,276
2010	3	1,453,208	108,417	48,463	4,448	205	75	43	95	12,568	1,627,522
2010	4	1,453,757	108,685	48,680	4,438	205	81	43	88	12,554	1,628,531
2010	5	1,452,382	108,862	48,828	4,432	209	84	44	81	12,538	1,627,460
2010	6	1,451,227	109,057	48,701	4,431	209	85	44	80	12,525	1,626,359
2010	7	1,450,319	109,189	48,641	4,428	208	84	43	79	12,509	1,625,500
2010	8	1,451,889	109,228	48,603	4,420	208	81	43	80	12,486	1,627,038
2010	9	1,452,402	109,220	48,600	4,420	208	82	44	81	12,424	1,627,481
2010	10	1,451,807	108,712	48,687	4,408	209	81	43	81	12,425	1,626,453
2010	11	1,453,379	108,658	48,461	4,421	211	80	44	81	12,417	1,627,752
2010	12	1,455,190	108,853	48,375	4,425	210	80	43	80	12,430	1,629,686
2011	1	1,456,482	109,040	48,230	4,417	213	80	44	79	12,427	1,631,012
2011	2	1,457,468	109,112	48,182	4,417	212	81	47	77	12,420	1,632,016
2011	3	1,457,702	109,129	48,218	4,419	212	81	46	78	12,413	1,632,298
2011	4	1,457,550	109,128	48,732	4,417	212	79	45	80	12,412	1,632,655
2011	5	1,456,546	109,324	48,919	4,418	210	79	44	81	12,393	1,632,014
2011	6	1,454,749	109,307	48,960	4,422	210	78	44	79	12,375	1,630,224
2011	7	1,454,042	109,375	48,895	4,423	208	77	44	79	12,347	1,629,490
2011	8	1,455,517	109,483	48,832	4,417	208	78	44	79	12,327	1,630,985
2011	9	1,454,873	109,337	48,865	4,418	208	77	44	79	12,329	1,630,230
2011	10	1,453,830	109,078	48,781	4,409	207	77	45	79	12,313	1,628,819
2011	11	1,455,117	108,967	48,560	4,410	207	78	45	79	12,295	1,629,758
2011	12	1,456,294	109,183	48,473	4,411	207	79	45	79	12,274	1,631,045
2012	1	1,458,286	109,427	48,330	4,444	219	80	42	29	12,274	1,633,131
2012	2	1,459,388	109,523	48,258	4,442	221	80	41	22	12,277	1,634,252
2012	3	1,459,233	109,609	48,345	4,433	222	80	42	22	12,278	1,634,264
2012	4	1,459,722	109,996	48,427	4,450	223	81	40	21	12,268	1,635,228
2012	5	1,456,982	110,337	48,460	4,439	224	81	38	20	12,249	1,632,830
2012	6	1,745,191	110,409	48,397	4,444	221	81	38	20	12,239	1,921,040
2012	7	1,746,300	110,540	48,389	4,443	221	83	38	20	12,227	1,922,261
2012	8	1,459,156	110,734	48,301	4,440	221	80	38	22	12,209	1,635,201
2012	9	1,459,260	110,540	48,422	4,442	221	80	36	22	12,201	1,635,224
2012	10	1,458,627	110,379	48,255	4,442	220	79	36	23	12,202	1,634,263
2012	11	1,459,910	110,357	48,031	4,444	221	76	36	25	12,190	1,635,290
2012	12	1,461,473	110,403	47,964	4,452	221	77	36	25	12,191	1,636,842
2013	1	1,463,080	110,548	47,899	4,456	221	76	36	25	12,174	1,638,515
2013	2	1,463,946	110,587	47,855	4,462	219	76	37	26	12,073	1,639,281
2013	3	1,464,737	110,495	48,025	4,467	218	83	37	19	12,066	1,640,147
2013	4	1,465,009	110,767	48,290	4,460	218	81	37	20	12,038	1,640,920
2013	5	1,463,943	110,760	48,620	4,469	214	74	37	27	12,014	1,640,158
2013	6	1,463,628	110,738	48,748	4,475	211	81	38	20	12,012	1,639,951
2013	7	1,463,168	110,783	48,799	4,476	214	91	39	11	11,995	1,639,576
2013	8	1,463,756	110,854	48,715	4,487	211	92	39	9	11,962	1,640,125
2013	9	1,463,682	110,799	48,707	4,493	209	93	39	10	11,958	1,639,990
2013	10	1,463,225	110,624	48,666	4,489	210	95	38	9	11,940	1,639,296
2013	11	1,464,818	110,541	48,574	4,496	210	95	39	9	11,923	1,640,705
2013	12	1,466,422	110,671	48,537	4,500	208	95	39	8	11,926	1,642,406
2014	1	1,467,651	110,812	48,467	4,504	208	95	38	9	11,911	1,643,695
2014	2	1,468,190	110,802	48,451	4,505	209	95	39	8	11,909	1,644,208
2014	3	1,468,627	110,425	48,812	4,510	210	94	39	8	11,887	1,644,612
2014	4	1,467,811	110,039	49,497	4,515	208	94	40	8	11,878	1,644,090
2014	5	1,466,342	110,202	49,622	4,515	205	94	40	8	11,858	1,642,886
2014	6	1,465,366	110,254	49,616	4,521	205	95	41	7	11,854	1,641,959
2014	7	1,463,825	110,435	49,487	4,517	204	96	40	7	11,842	1,640,453
2014	8	1,464,278	110,674	49,263	4,510	204	97	40	7	11,823	1,640,896
2014	9	1,465,331	110,863	49,129	4,509	203	97	40	8	11,820	1,642,000
2014	10	1,464,153	110,698	49,072	4,514	202	96	39	8	11,802	1,640,584
2014	11	1,467,049	110,743	48,902	4,515	201	96	38	8	11,796	1,643,348
2014	12	1,468,853	110,960	48,848	4,519	201	96	38	8	11,795	1,645,318
2015	1	1,471,048	111,107	48,795	4,527	201	96	38	8	11,783	1,647,603
2015	2	1,472,524	111,188	48,782	4,526	201	97	38	8	11,780	1,649,144
2015	3	1,472,984	111,060	48,915	4,526	199	96	38	8	11,780	1,649,606
2015	4	1,472,988	110,942	49,359	4,534	199	97	37	8	11,771	1,649,935
2015	5	1,471,344	111,260	49,412	4,540	197	97	37	8	11,750	1,648,645
2015	6	1,470,952	111,356	49,414	4,538	198	95	38	6	11,732	1,648,329
2015	7	1,470,267	111,527	49,278	4,537	198	94	38	6	11,710	1,647,655
2015	8	1,470,862	111,753	49,139	4,532	198	93	38	6	11,689	1,648,310
2015	9	1,471,599	111,772	49,235	4,534	197	93	38	6	11,662	1,649,136
2015	10	1,471,613	111,570	49,218	4,537	197	93	38	6	11,616	1,648,888
2015	11	1,473,600	111,658	49,033	4,535	197	93	38	6	11,607	1,650,767
2015	12	1,475,131	111,865	49,055	4,540	197	93	37	6	11,590	1,652,514
2016	1	1,477,893	112,154	48,956	4,542	196	93	37	6	11,596	1,655,473
2016	2	1,479,189	112,369	48,911	4,540	196	94	37	6	11,607	1,656,949
2016	3	1,479,790	112,572	48,863	4,544	197	95	37	6	11,600	1,657,704
2016	4	1,480,517	112,917	48,981	4,554	197	95	37	6	11,595	1,658,899
2016	5	1,480,050	113,110	49,045	4,551	197	95	37	6	11,576	1,658,667
2016	6	1,479,438	113,313	49,037	4,558	197	94	37	6	11,546	1,658,226
2016	7	1,478,962	113,503	49,002	4,554	195	94	37	6	11,545	1,657,898
2016	8	1,480,278	113,682	48,940	4,561	195	94	37	6	11,539	1,659,332
2016	9	1,480,430	113,545	49,118	4,558	195	95	37	6	11,525	1,659,509
2016	10	1,480,903	113,394	49,298	4,554	194	95	37	6	11,527	1,660,008

MONTHLY ***(Historicals:*** ***Actuals)***
GWH

Year	Month	SC1	SC2ND	SC2D	SC3	SC3A	SC4	SC7	SC11_12	NYPA R&E	NYPA RNY	NYPA HLF	NYPA PP	NYPA St Lawrence	STREET LIGHTING	TOTAL
2010	1	1,216	64	396	563	350	32	34	122	316	-	-	-	-	24	3,117
2010	2	1,030	59	360	513	347	37	30	103	303	-	-	-	-	19	2,801
2010	3	996	58	359	519	375	35	31	116	311	-	-	-	-	19	2,817
2010	4	845	50	340	520	336	52	30	87	307	-	-	-	-	17	2,584
2010	5	749	44	315	493	349	62	24	68	279	-	-	-	-	14	2,397
2010	6	857	47	355	527	342	45	24	94	291	-	-	-	-	14	2,597
2010	7	1,107	71	536	440	440	61	34	100	163	-	-	-	-	14	2,966
2010	8	1,150	57	419	564	463	60	29	100	511	-	-	-	-	14	3,368
2010	9	990	53	395	540	374	63	27	99	347	-	-	-	-	17	2,906
2010	10	782	46	334	529	364	44	14	83	322	-	-	-	-	18	2,535
2010	11	820	46	319	478	380	39	35	91	303	-	-	-	-	19	2,530
2010	12	1,020	54	355	531	388	38	33	83	318	-	-	-	-	22	2,842
2011	1	1,155	61	376	537	401	57	30	83	338	-	-	-	-	22	3,060
2011	2	1,075	60	358	523	352	51	28	82	299	-	-	-	-	22	2,851
2011	3	1,025	59	359	530	395	63	29	88	341	-	-	-	-	16	2,906
2011	4	938	54	348	521	350	52	27	85	312	-	-	-	-	16	2,703
2011	5	804	46	320	493	372	67	25	95	346	-	-	-	-	14	2,583
2011	6	856	48	354	532	406	69	22	91	330	-	-	-	-	14	2,722
2011	7	1,022	52	397	568	346	59	30	92	340	-	-	-	-	14	2,920
2011	8	1,169	58	372	498	157	0	20	36	-	-	-	-	-	14	2,325
2011	9	966	52	382	548	414	153	33	88	1,048	-	-	-	-	17	3,702
2011	10	823	47	340	527	389	50	16	90	313	-	-	-	-	18	2,613
2011	11	853	48	330	501	363	35	37	83	189	-	-	-	-	20	2,459
2011	12	962	52	339	513	316	35	25	76	361	-	-	-	-	22	2,701
2012	1	1,077	57	348	527	501	41	15	33	333	-	-	-	-	21	2,953
2012	2	1,035	58	348	486	404	47	12	21	303	-	-	-	-	19	2,734
2012	3	968	56	353	537	424	41	13	27	308	-	-	-	-	20	2,747
2012	4	842	49	331	541	428	16	11	21	139	-	-	-	-	16	2,394
2012	5	822	48	320	512	520	70	15	23	471	-	17	1	-	15	2,835
2012	6	893	51	368	560	459	53	14	3	259	-	16	1	-	14	2,690
2012	7	1,088	55	391	560	377	42	12	22	326	-	14	1	-	13	2,902
2012	8	1,199	62	427	578	446	39	15	26	297	88	14	1	-	16	3,207
2012	9	1,031	56	398	602	456	40	15	45	243	90	12	1	-	16	3,004
2012	10	769	45	327	510	397	36	14	23	342	99	12	1	-	17	2,594
2012	11	826	47	315	493	390	31	12	22	276	102	8	0	-	20	2,543
2012	12	1,024	57	350	522	394	42	12	21	242	106	9	0	-	21	2,800
2013	1	1,173	65	363	535	395	35	12	25	359	96	9	0	-	20	3,087
2013	2	1,070	58	366	534	389	46	11	18	293	110	8	0	-	16	2,921
2013	3	995	58	343	504	383	40	12	24	341	120	8	1	-	15	2,843
2013	4	941	55	340	525	380	51	12	23	197	114	8	0	-	25	2,672
2013	5	835	50	342	518	417	43	12	24	338	112	8	1	-	16	2,716
2013	6	861	48	345	528	381	42	16	23	290	111	8	1	-	13	2,666
2013	7	1,084	53	388	553	414	51	19	22	354	120	8	1	-	14	3,081
2013	8	1,086	57	415	591	406	48	19	20	313	122	9	1	-	15	3,102
2013	9	982	52	382	550	429	56	18	18	305	113	9	1	-	16	2,931
2013	10	777	45	324	521	366	64	15	22	299	117	10	1	-	18	2,579
2013	11	821	46	317	510	371	48	13	22	303	119	8	1	-	19	2,598
2013	12	1,066	55	355	525	390	43	11	19	301	116	8	1	-	21	2,910
2014	1	1,271	65	383	562	390	43	15	22	296	122	8	1	-	23	3,202
2014	2	1,150	64	373	561	384	62	11	21	338	113	7	1	-	19	3,103
2014	3	1,090	62	370	535	359	45	12	23	276	41	8	1	-	17	2,839
2014	4	933	53	334	547	481	52	16	22	356	185	9	1	-	17	3,004
2014	5	832	47	335	521	379	57	4	23	324	105	9	1	-	14	2,655
2014	6	792	44	337	529	397	58	29	23	292	130	9	1	-	13	2,653
2014	7	977	50	373	559	409	58	25	23	311	123	9	1	-	14	2,933
2014	8	1,006	52	394	572	429	59	19	24	327	124	9	1	-	14	3,028
2014	9	918	48	362	557	410	46	18	23	300	111	9	1	-	16	2,819
2014	10	797	44	336	529	394	53	19	23	304	127	9	1	-	18	2,652
2014	11	845	47	331	504	392	50	18	24	296	111	8	1	-	19	2,648
2014	12	1,024	55	350	538	391	51	14	22	305	127	8	1	-	21	2,908
2015	1	1,161	59	399	555	413	53	14	24	329	131	8	1	-	23	3,172
2015	2	1,153	63	343	553	396	48	13	23	272	121	8	1	-	19	3,011
2015	3	1,107	61	369	542	403	57	15	26	307	135	9	1	-	17	3,049
2015	4	946	54	350	531	386	45	15	24	270	123	9	1	-	18	2,770
2015	5	781	45	323	503	403	54	16	26	8	137	9	1	-	14	2,320
2015	6	861	46	354	542	375	57	19	25	549	128	8	1	-	14	2,980
2015	7	925	49	367	563	439	56	19	23	362	135	13	1	-	13	2,966
2015	8	1,069	53	399	576	430	49	19	26	248	143	13	1	-	14	3,040
2015	9	1,054	53	397	585	433	61	20	25	360	135	9	1	-	17	3,150
2015	10	840	46	346	526	385	49	17	26	263	138	9	1	0.38	17	2,665
2015	11	776	44	310	493	386	45	15	25	278	129	8	1	0.41	19	2,530
2015	12	1,021	56	374	530	348	48	15	24	335	131	10	10	0.48	20	2,922
2016	1	1,093	57	363	540	411	47	15	25	295	131	9	1	0.58	23	3,010
2016	2	1,001	57	347	532	370	46	14	25	277	127	9	1	0.55	19	2,825
2016	3	1,001	58	361	531	355	46	15	25	282	124	9	1	0.52	18	2,827
2016	4	874	50	330	524	374	54	14	24	286	128	8	1	0.46	16	2,684
2016	5	739	44	304	486	366	64	16	25	282	127	9	1	0.38	14	2,479
2016	6	895	48	365	540	374	64	17	24	265	132	9	1	0.36	14	2,747
2016	7	1,087	55	407	585	412	70	17	22	282	134	9	1	0.40	13	3,094
2016	8	1,178	57	407	591	431	69	20	26	274	138	9	1	0.42	16	3,216
2016	9	1,095	55	404	593	399	58	17	24	255	129	8	1	0.32	16	3,054
2016	10	817	46	345	533	403	44	12	27	262	134	9	1	0.35	18	2,649

Residential Energy Intensity Targets

	Targets			
	Year-over-year percent reduction			
	2017	2018	2019	2020
Min	0.57%	0.57%	0.58%	0.58%
Target	0.78%	0.78%	0.79%	0.80%
Max	1.16%	1.23%	1.25%	1.26%

Residential Sales, GWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
11,444	11,543	11,583	11,739	11,656	11,592	11,471	*11,434*	*11,382*	*11,383*	*11,362*

Residential Customer Counts (actuals through 2016, projected for 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
1,457,025	1,460,359	1,463,542	1,468,646	1,470,920	1,476,460	1,484,868	*1,486,248*	*1,489,763*	*1,493,723*	*1,497,732*

Energy Intensity (Residential) -- Target Calculation
MWh/customer

	Historic							*Forecast*			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Historic	7.85	7.90	7.91	7.99	7.92	7.85	7.73				
Forecast								*7.69*	*7.64*	*7.62*	*7.59*
Min								7.68	7.64	7.59	7.55
Target								7.67	7.61	7.55	7.49
Max								7.64	7.54	7.45	7.35

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Commercial Energy Intensity Targets

	Targets			
	Year-over-year percent reduction			
	2017	2018	2019	2020
Min	2.22%	1.00%	1.01%	1.02%
Target	2.32%	1.13%	1.14%	1.15%
Max	2.44%	1.33%	1.34%	1.36%

Commercial Sales, GWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
12,644	12,604	12,521	12,502	12,645	12,551	12,358	*12,175*	*12,040*	*11,995*	*11,915*

Commercial Customer Counts (actuals through 2016, projected for 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
163,329	163,676	164,666	164,892	165,464	166,357	167,985	*168,478*	*168,855*	*169,406*	*170,014*

Energy Intensity (Commercial) -- Target Calculation
MWh/customer

	Historical							*Forecast*			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseline	77.42	77.01	76.04	75.82	76.42	75.45	73.57				
Forecast								*72.26*	*71.30*	*70.81*	*70.08*
Min								71.93	71.22	70.50	69.79
Target								71.86	71.05	70.24	69.43
Max								71.77	70.82	69.87	68.92

	Percent Reduction from 2016			
	2017	2018	2019	2020
Min	2.22%	3.19%	4.17%	5.14%
Target	2.32%	3.42%	4.52%	5.62%
Max	2.44%	3.73%	5.03%	6.32%

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Low Income Energy Intensity Targets

	Targets			
	Year to year percent change			
	2017	2018	2019	2020
Min	0.02%	0.09%	0.09%	0.09%
Target	0.10%	0.53%	0.53%	0.53%
Max	0.53%	1.06%	1.25%	1.27%

Low Income Sales, kWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
1,121	1,193	1,088	1,009	966	977	908	*858*	*812*	*769*	*726*

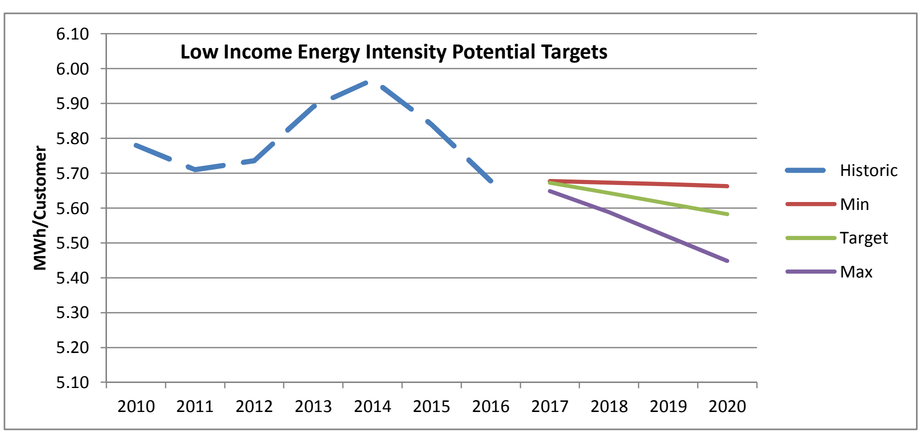
Low Income Customer Count (actuals through 2016, projected for 2017-2020)

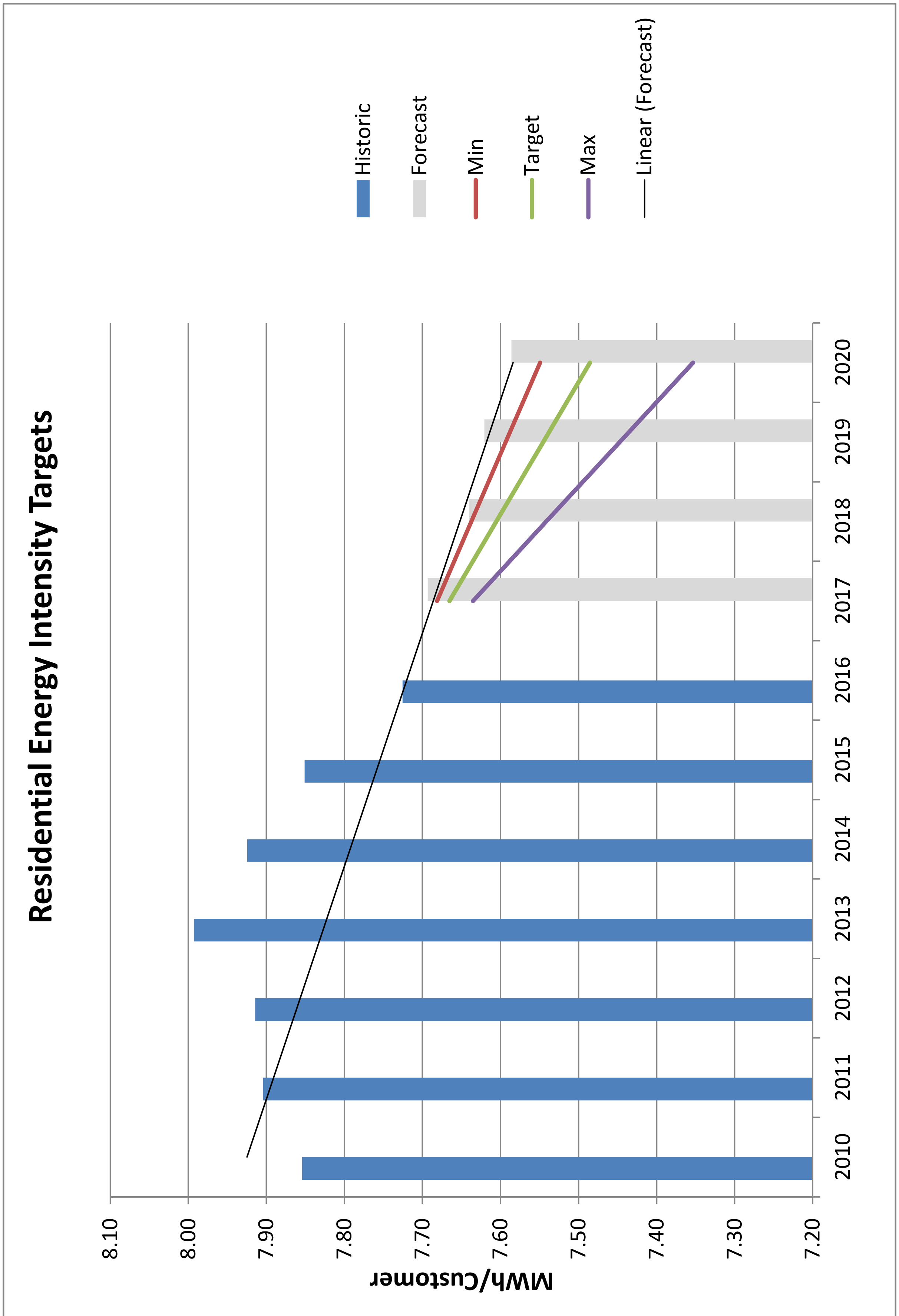
2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
193,945	208,842	189,657	171,343	161,864	167,349	159,958	*148,773*	*140,932*	*133,091*	*125,210*

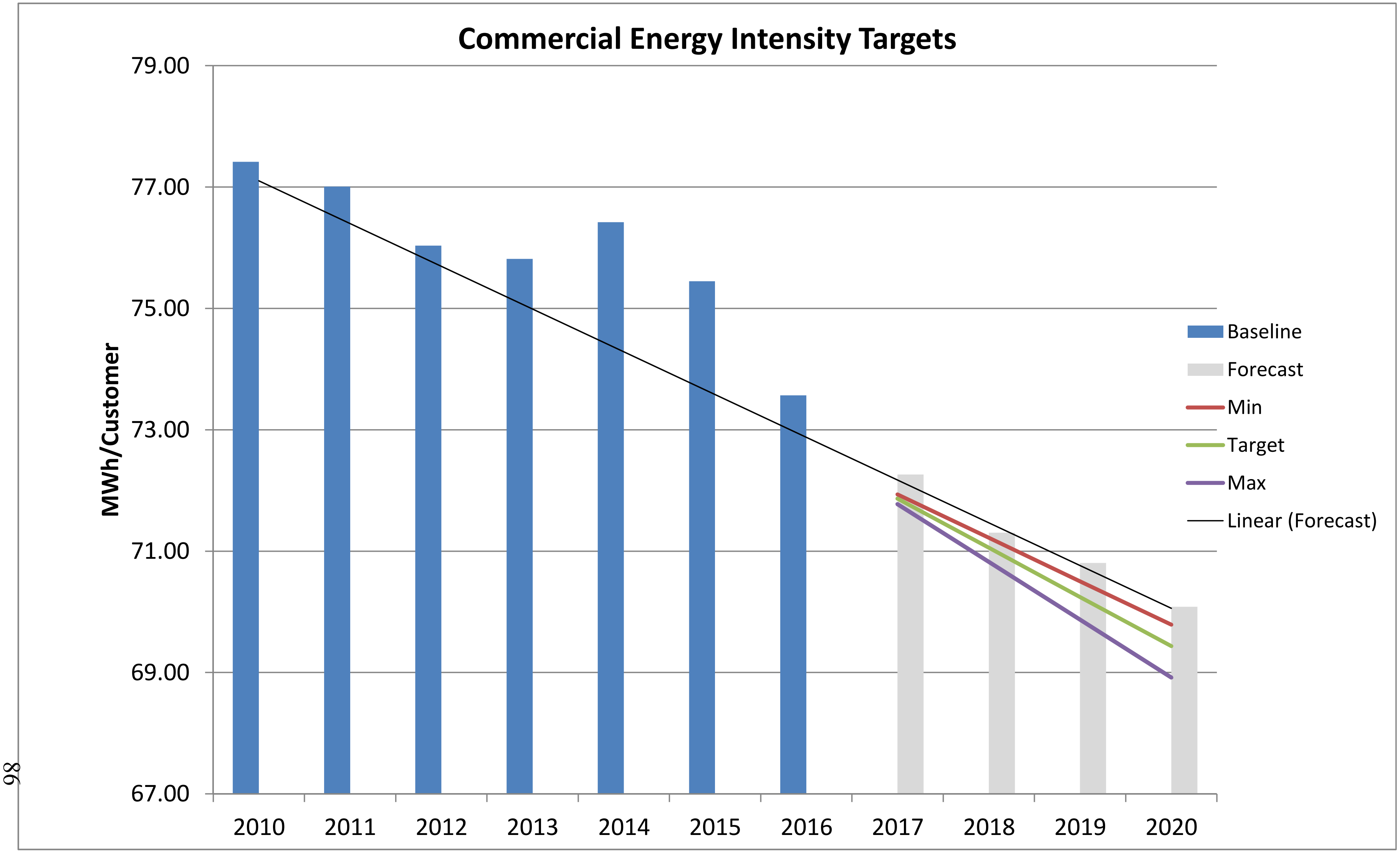
Energy Intensity (Low Income) -- Target Calculation
MWh/customer

	Historic							*Forecast*			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Historic	5.78	5.71	5.74	5.89	5.97	5.84	5.68				
Forecast								*5.76*	*5.76*	*5.78*	*5.80*
Min								5.68	5.67	5.67	5.66
Target								5.67	5.64	5.61	5.58
Max								5.65	5.59	5.52	5.45

	Percent Reduction from 2016			
	2017	2018	2019	2020
Min	0.02%	0.10%	0.19%	0.28%
Target	0.10%	0.63%	1.16%	1.68%
Max	0.53%	1.58%	2.82%	4.05%




Residential Energy Intensity Targets
MWh/Customer
8.10
8.00
7.90
7.80
7.70
7.60
7.50
7.40
7.30
7.20
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Historic
Forecast
Min
Target
Max
Linear (Forecast)



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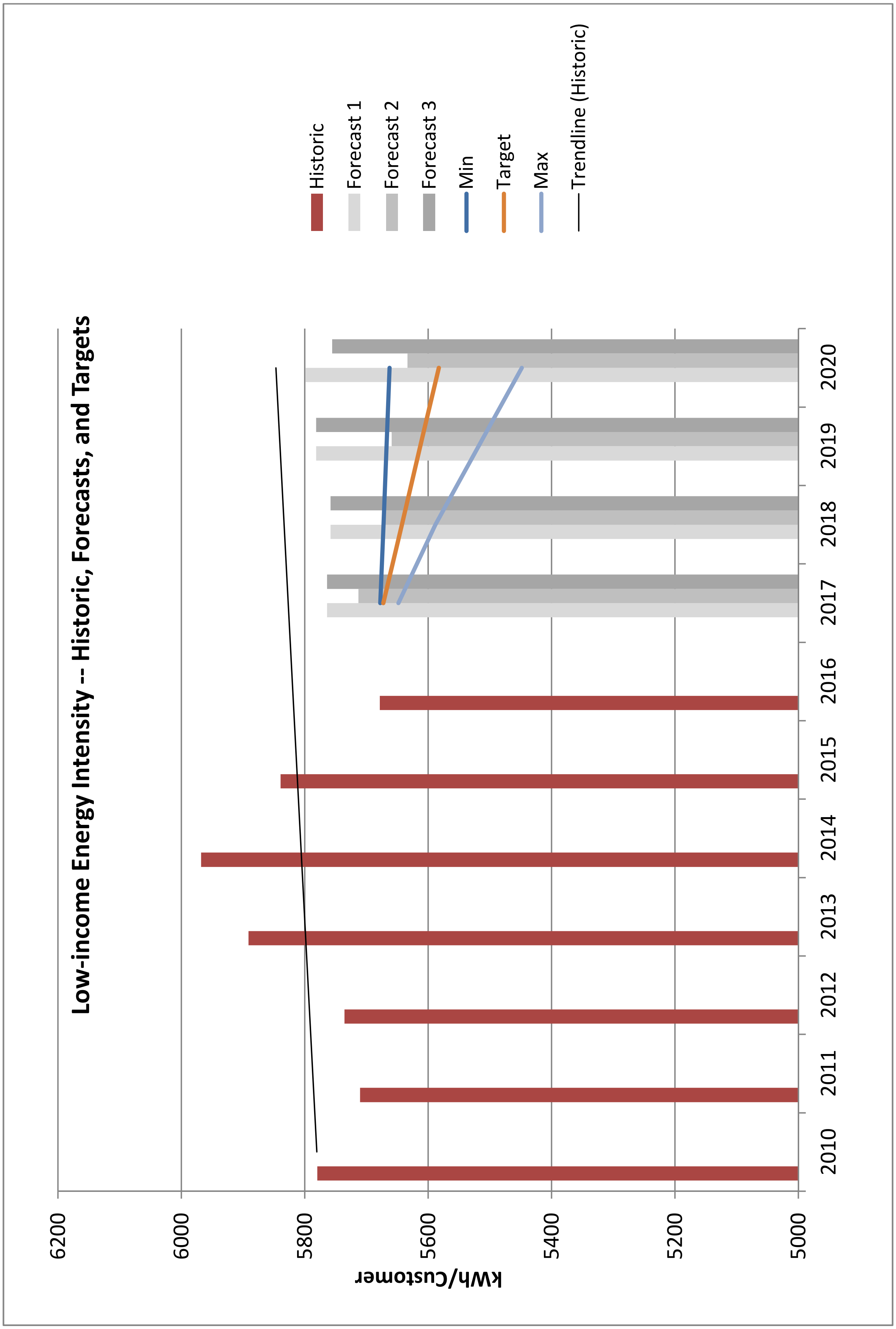
Low-income Energy Intensity -- Historic, Forecasts, and Targets
kWh/Customer
6200
6000
5800
5600
5400
5200
5000
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Historic
Forecast 1
Forecast 2
Forecast 3
Min
Target
Max
Trendline (Historic)

Niagara Mohawk Power Corporation
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Case 17-E-0238
Attachment 2 to DPS-131 JT-1
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C4 RIDER Results

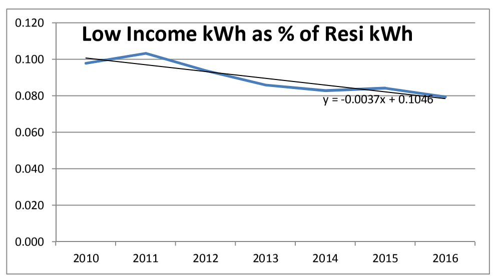
Year	TOTAL_KWH	TOTAL_BILL_DAYS	NUMBER_HEAP	NUMBER_C4	NUMBER_ACCTS	KWh/Custc	Total RESI customer accounts	Total RESI Sales actuals (GWh)	C4 share of resi Sales	C4 share of Resi Customers	Weather normalization ratios from sales forecast	Low Income Weather normalized kWH	Weather-normalized KWh/customer	Total RESI Weather-normalized	Low Income Weather-normalized GWh
2010	1,134,512,522	53846422	121355	193945	193945	5850	1,457,025	11582	0.098	0.1331	0.988	1,120,995,757	5780	11,444	1121.0
2011	1,205,556,156	57379191	122576	208842	208842	5773	1,460,359	11669	0.103	0.1430	0.989	1,192,567,871	5710	11,543	1192.6
2012	1,088,304,607	52967004	112049	189657	189657	5738	1,463,542	11588	0.094	0.1296	1.000	1,087,821,418	5736	11,583	1087.8
2013	1,007,324,421	48086366	85172	171343	171343	5879	1,468,646	11715	0.086	0.1167	1.002	1,009,412,584	5891	11,739	1009.4
2014	966,461,939	45728619	89723	161864	161864	5971	1,470,920	11661	0.083	0.1100	1.000	966,029,814	5968	11,656	966.0
2015	987,957,994	47308742	117482	167349	167349	5904	1,476,460	11719	0.084	0.1133	0.989	977,219,132	5839	11,592	977.2
2016	920,111,285	45235754	82370	159958	159958	5752	1,484,868	11563	0.080	0.1077	0.987	908,310,764	5678	11,471	908.3
2017					148773		1,486,248		0.075	0.1001		857,550,000	5764	11,434	857.6
2018					140932		1,489,763		0.071	0.0946		811,536,600	5758	11,382	811.5
2019					133091		1,493,723		0.068	0.0891		769,490,800	5782	11,383	769.5
2020					125210		1,497,732		0.064	0.0836		726,031,800	5798	11,362	726.0

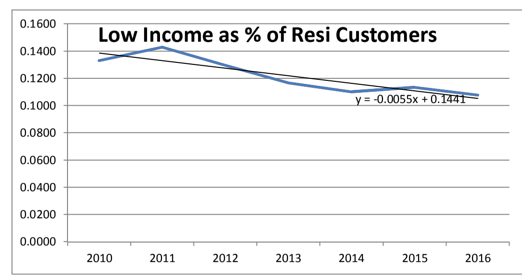
MWh/Customer Forecasts

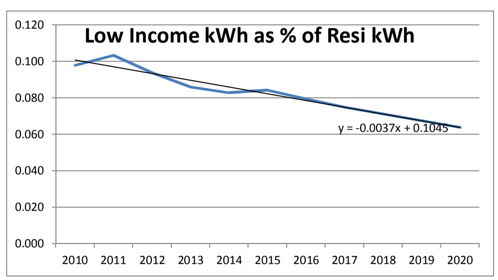
1. Assume low income share of customers and share of total energy use continue to decline at their respective rates		2. Assume shares stay at constant (2016) level		3. Assume shares stop declining in 2019	
MWh/Customer Forecast		MWh/Customer Forecast		MWh/Customer Forecast	
2017	5764	2017	5713	2017	5764
2018	5758	2018	5674	2018	5758
2019	5782	2019	5659	2019	5782
2020	5798	2020	5634	2020	5756
Customer Forecast		Customer Forecast		Customer Forecast	
2017	148773	2017	160107	2017	148773
2018	140932	2018	160485	2018	140932
2019	133091	2019	160912	2019	133091
2020	125210	2020	161344	2020	133448
Sales Forecast (GWh)		Sales Forecast (GWh)		Sales Forecast (GWh)	
2017	858	2017	915	2017	858
2018	812	2018	911	2018	812
2019	769	2019	911	2019	769
2020	726	2020	909	2020	768

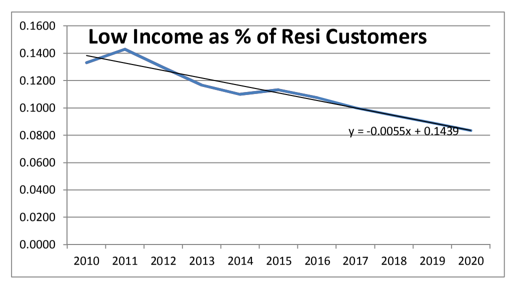
Graph historic and forecasts

Year	Historic	Forecast 1	Forecast 2	Forecast 3	Min	Target	Max
2010	5780						
2011	5710						
2012	5736						
2013	5891						
2014	5968						
2015	5839						
2016	5678						
2017		5764.1	5713.2	5764.1	5677.5	5672.8	5648.4
2018		5758.4	5673.8	5758.4	5672.5	5642.8	5588.4
2019		5781.7	5659.2	5781.7	5667.5	5612.8	5518.4
2020		5798.5	5633.7	5755.6	5662.5	5582.8	5448.4









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NIAGARA MOHAWK POWER CORPORATION
d/b/a National Grid

Residential Energy Intensity Targets

	Targets			
	Year-over-year percent reduction			
	2017	2018	2019	2020
Min	0.57%	0.57%	0.58%	0.58%
Target	0.78%	0.78%	0.79%	0.80%
Max	1.16%	1.23%	1.25%	1.26%

Residential Sales, GWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)*

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
11,444	11,543	11,583	11,739	11,656	11,592	11,471	*11,416*	*11,334*	*11,308*	*11,255*

Residential Customer Counts (actuals through 2016, projected for 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
1,457,025	1,460,359	1,463,542	1,468,646	1,470,920	1,476,460	1,484,868	*1,486,714*	*1,490,054*	*1,494,001*	*1,498,021*

Energy Intensity (Residential) -- Target Calculation
MWh/customer

	Historic							*Forecast*			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Historic	7.85	7.90	7.91	7.99	7.92	7.85	7.73				
Forecast								*7.68*	*7.61*	*7.57*	*7.51*
Min								7.68	7.64	7.59	7.55
Target								7.67	7.61	7.55	7.49
Max								7.64	7.54	7.45	7.35

	Percent Reduction from 2016			
	2017	2018	2019	2020
Min	0.57%	1.14%	1.71%	2.28%
Target	0.78%	1.55%	2.33%	3.11%
Max	1.16%	2.38%	3.60%	4.82%

Exhibit __(ECP-6CU)
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Commercial Energy Intensity Targets

	Targets			
	Year-over-year percent reduction			
	2017	**2018**	**2019**	**2020**
Min	2.22%	1.00%	1.01%	1.02%
Target	2.32%	1.13%	1.14%	1.15%
Max	2.44%	1.33%	1.34%	1.36%

Commercial Sales, GWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)*

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
12,644	12,604	12,521	12,502	12,645	12,551	12,358	*12,331*	*12,294*	*12,283*	*12,182*

Commercial Customer Counts (actuals through 2016, projected for 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
163,329	163,676	164,666	164,892	165,464	166,357	167,985	*168,643*	*168,994*	*169,533*	*170,139*

Energy Intensity (Commercial) -- Target Calculation
MWh/customer

	Historical							*Forecast*			
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Baseline	77.42	77.01	76.04	75.82	76.42	75.45	73.57				
Forecast								*73.12*	*72.75*	*72.45*	*71.60*
Min								71.93	71.22	70.50	69.79
Target								71.86	71.05	70.24	69.43
Max								71.77	70.82	69.87	68.92

	Percent Reduction from 2016			
	2017	**2018**	**2019**	**2020**
Min	2.22%	3.19%	4.17%	5.14%
Target	2.32%	3.42%	4.52%	5.62%
Max	2.44%	3.73%	5.03%	6.32%

Exhibit __(ECP-6CU)
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Low Income Energy Intensity Targets

	Targets			
	Year to year percent change			
	2017	2018	2019	2020
Min	0.02%	0.09%	0.09%	0.09%
Target	0.10%	0.53%	0.53%	0.53%
Max	0.53%	1.06%	1.25%	1.27%

Low Income Sales, kWh (Weather-normalized actuals through 2016, weather-normalized forecast 2017-2020)*

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
1,121	1,193	1,088	1,009	966	977	908	*856*	*808*	*764*	*719*

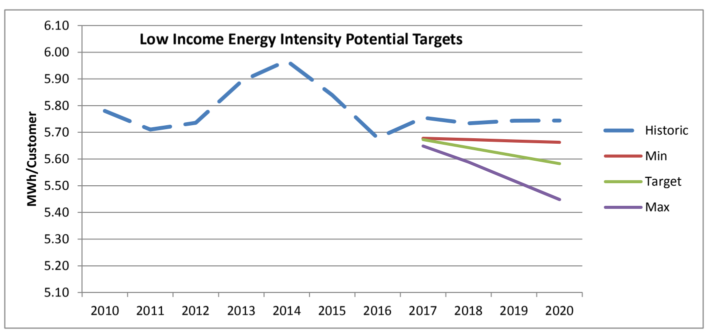
Low Income Customer Count (actuals through 2016, projected for 2017-2020)

2010	2011	2012	2013	2014	2015	2016	*2017*	*2018*	*2019*	*2020*
193,945	208,842	189,657	171,343	161,864	167,349	159,958	*148,773*	*140,932*	*133,091*	*125,210*

Energy Intensity (Low Income) -- Target Calculation
MWh/customer

	Historic							*Forecast*			
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Historic	5.78	5.71	5.74	5.89	5.97	5.84	5.68				
Forecast								*5.76*	*5.73*	*5.74*	*5.74*
Min								5.68	5.67	5.67	5.66
Target								5.67	5.64	5.61	5.58
Max								5.65	5.59	5.52	5.45

	Percent Reduction from 2016			
	2017	2018	2019	2020
Min	0.02%	0.10%	0.19%	0.28%
Target	0.10%	0.63%	1.16%	1.68%
Max	0.53%	1.58%	2.82%	4.05%



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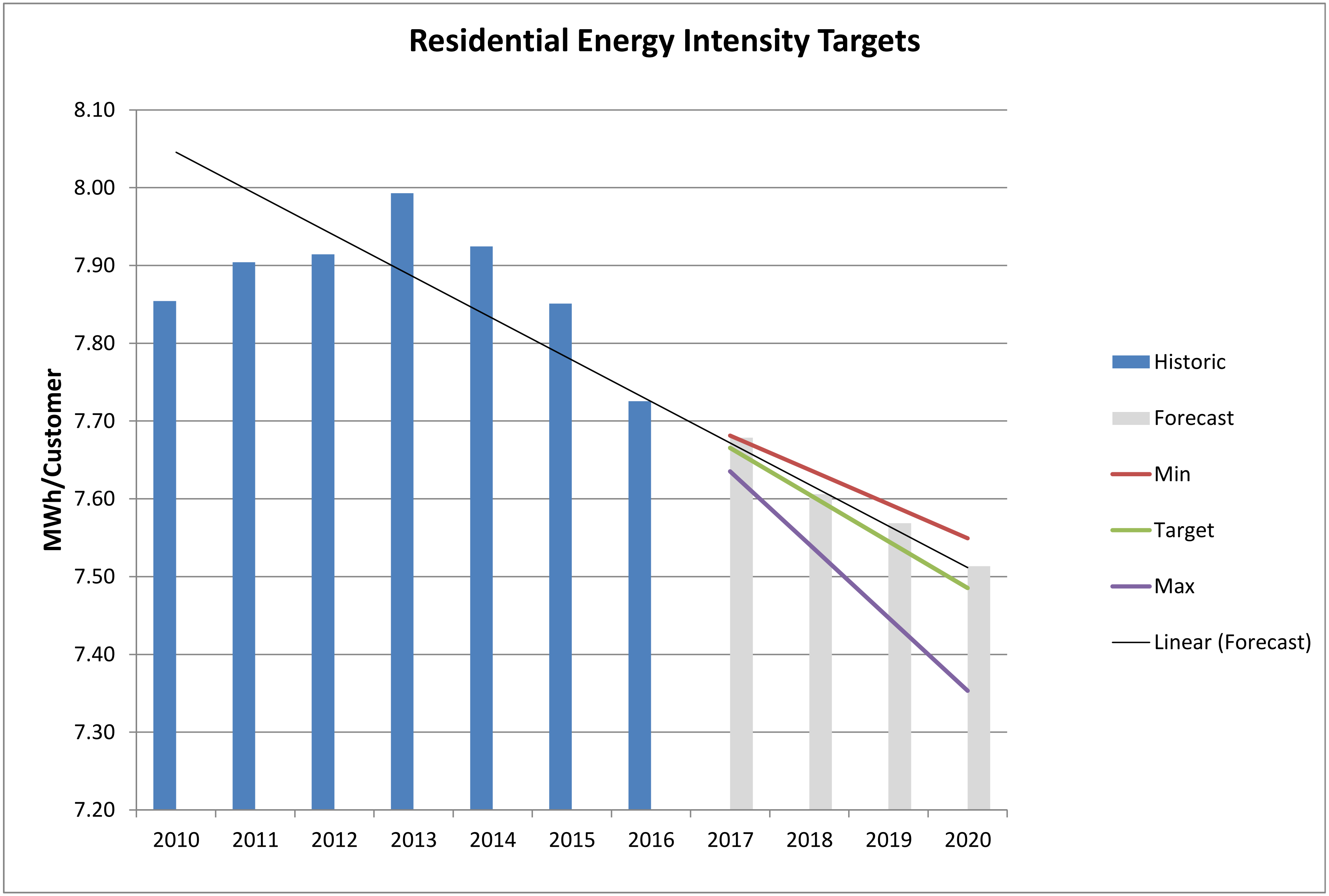

Exhibit __(ECP-6CU)
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Exhibit __(ECP-6CU)
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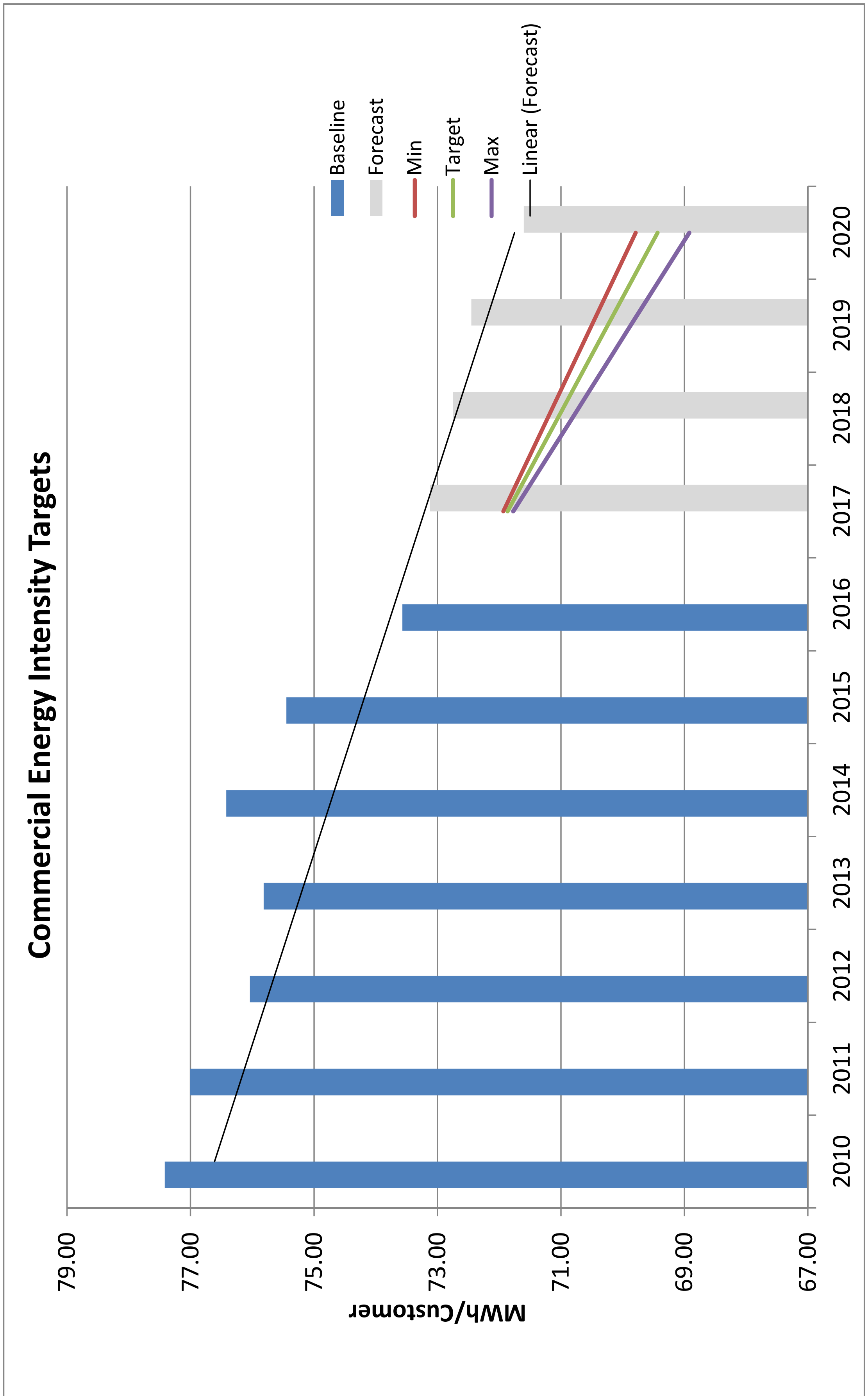

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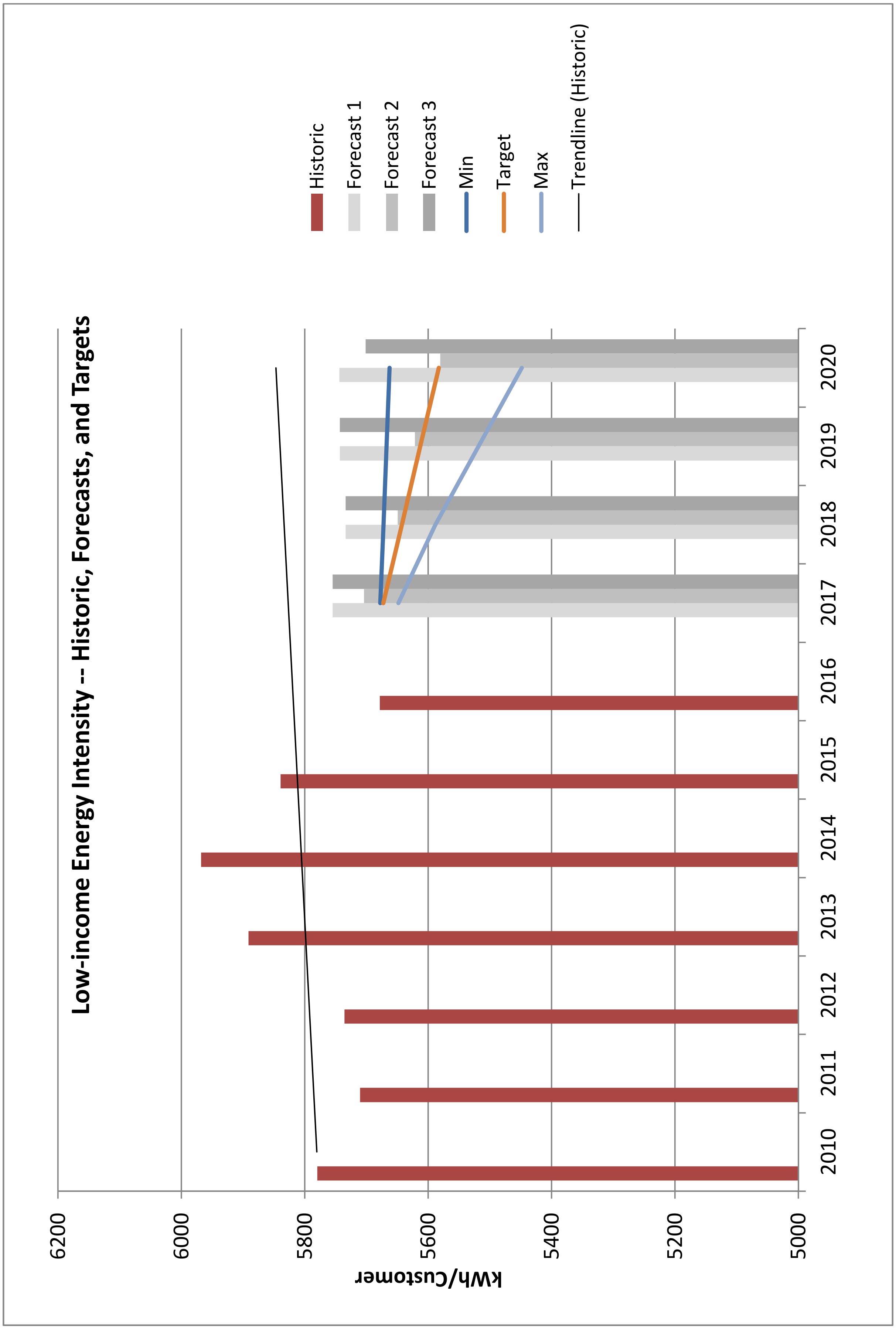


C4 RIDER Results

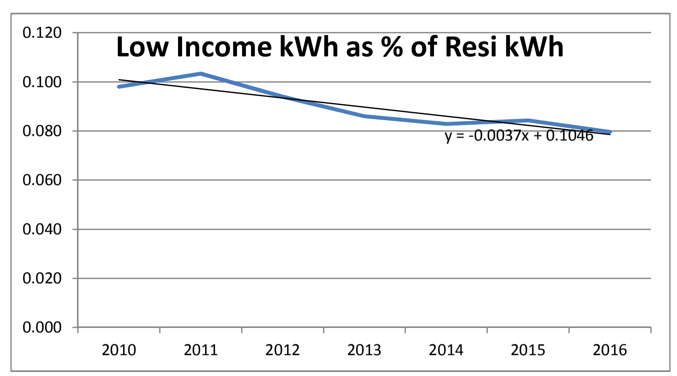
Year	TOTAL_KWH	TOTAL_BILL_DAYS	NUMBER_HEAP	NUMBER_C4	NUMBER_ACCTS	KWh/Custc	Total RESI customer accounts	Total RESI Sales actuals (GWh)	C4 share of resi Sales	C4 share of Resi Customers	Weather normalization ratios from sales forecast	Low Income Weather-normalized kWH	Weather-normalized KWh/customer	Total RESI Weather-normalized	Low Income Weather-normalized GWh
2010	1,134,512,522	53846422	121355	193945	193945	5850	1,457,025	11582	0.098	0.1331	0.988	1,120,995,757	5780	11,444	1121.0
2011	1,205,556,156	57379191	122576	208842	208842	5773	1,460,359	11669	0.103	0.1430	0.989	1,192,567,871	5710	11,543	1192.6
2012	1,088,304,607	52967004	112049	189657	189657	5738	1,463,542	11588	0.094	0.1296	1.000	1,087,821,418	5736	11,583	1087.8
2013	1,007,324,421	48086366	85172	171343	171343	5879	1,468,646	11715	0.086	0.1167	1.002	1,009,412,584	5891	11,739	1009.4
2014	966,461,939	45728619	89723	161864	161864	5971	1,470,920	11661	0.083	0.1100	1.000	966,029,814	5968	11,656	966.0
2015	987,957,994	47308742	117482	167349	167349	5904	1,476,460	11719	0.084	0.1133	0.989	977,219,132	5839	11,592	977.2
2016	920,111,285	45235754	82370	159958	159958	5752	1,484,868	11563	0.080	0.1077	0.987	908,310,764	5678	11,471	908.3
2017					148773		1,486,248		0.075	0.1001		856,207,355	5755	11,416	856.2
2018					140932		1,489,763		0.071	0.0946		808,080,983	5734	11,334	808.1
2019					133091		1,493,723		0.068	0.0891		764,391,595	5743	11,308	764.4
2020					125210		1,497,732		0.064	0.0836		719,200,279	5744	11,255	719.2

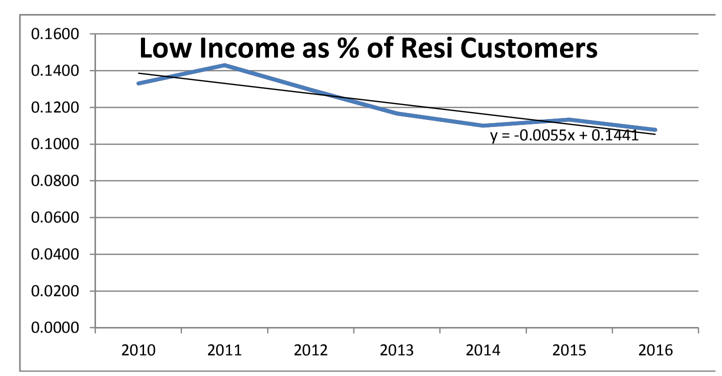
MWh/Customer Forecasts

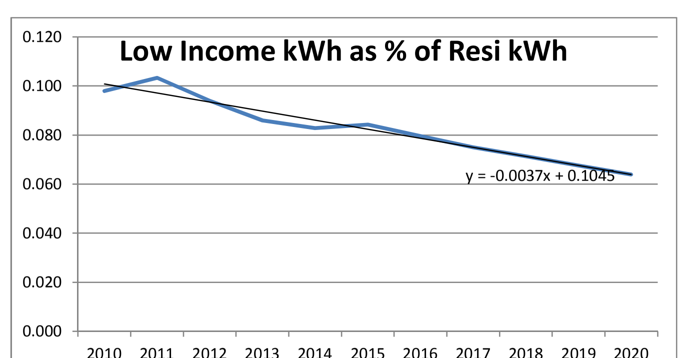
1. Assume low income share of customers and share of total energy use continue to decline at their respective rates		2. Assume shares stay at constant (2016) level		3. Assume shares stop declining in 2019	
	MWh/Customer Forecast		MWh/Customer Forecast		MWh/Customer Forecast
2017	5755	2017	5704	2017	5755
2018	5734	2018	5650	2018	5734
2019	5743	2019	5622	2019	5743
2020	5744	2020	5581	2020	5701
	Customer Forecast		Customer Forecast		Customer Forecast
2017	148773	2017	160107	2017	148773
2018	140932	2018	160485	2018	140932
2019	133091	2019	160912	2019	133091
2020	125210	2020	161344	2020	133448
	Sales Forecast (GWh)		Sales Forecast (GWh)		Sales Forecast (GWh)
2017	856	2017	913	2017	856
2018	808	2018	907	2018	808
2019	764	2019	905	2019	764
2020	719	2020	900	2020	761

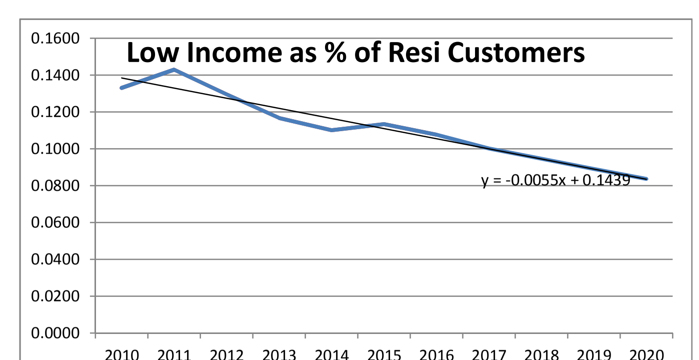
Graph historic and forecasts

Year	Historic	Forecast 1	Forecast 2	Forecast 3	Min	Target	Max
2010	5780						
2011	5710						
2012	5736						
2013	5891						
2014	5968						
2015	5839						
2016	5678						
2017		5755.1	5704.2	5755.1	5677.5	5672.8	5648.4
2018		5733.9	5649.6	5733.9	5672.5	5642.8	5588.4
2019		5743.4	5621.7	5743.4	5667.5	5612.8	5518.4
2020		5743.9	5580.7	5701.4	5662.5	5582.8	5448.4









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Date of Request: June 7, 2019 Request No. DPS-282 LMR-7
Due Date: June 19, 2017 NMPC Req. No. NM-745

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Lisa Rosi

TO: National Grid, Electric Customer Panel

SUBJECT: **INCREMENTAL GAS ENERGY EFFICIENCY EAM**

Request:

In all interrogatories, all requests for workpapers or supporting calculations shall be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact and unlocked.

On pages 69 through 72 of the Electric Customer Panel's (panel) Pre-Filed Direct Testimony, the panel proposed Incremental Gas Energy Efficiency (Gas EE) EAM. On pages 53 and 54 of its testimony, the panel also proposed a similar EAM related to Incremental Electric Energy Efficiency (Electric EE).

1. Explain how the Gas EE EAM is outcome-based instead of program-based.

2. Explain why the target and maximum Gas EE thresholds were proposed based on a 10% and 20% reduction from ETIP $/Dth costs, respectively, whereas the Electric EE thresholds were proposed based on a 20% and 35% reduction from ETIP $/kWh.

3. Explain why the Company proposed to earn an EAM based on 2017 performance completed prior to the Rate Year.

4. Provide the workpaper supporting the Benefit Cost Analysis performed by the Company relative to the Gas EE EAM, as shown in Exhibit_(ECP-5), Schedule 9.

Response:

1. The Incremental Gas EE EAM is program-based. The Company will make this correction in its Corrections and Updates filing.

2. Because the Gas ETIP portfolio is smaller than the Electric ETIP portfolio, it is more difficult to achieve economies of scale. Therefore, the Company assumed smaller cost reductions were possible for gas energy efficiency. Further, the ETIP budgeted cost per savings achieved decreases in the first rate year as a result of the Company adding to its energy savings target to reflect more program-specific funding available as costs shift out of the ETIP portfolio and into base rates. This results in a Gas ETIP portfolio cost savings of approximately 18 percent in the minimum EAM scenario.

3. In 2016, Niagara Mohawk along with the other Joint Utilities filed proposals for the System Efficiency, Energy Efficiency, and Interconnection EAMs. Consistent with the EAM proposals filed by Con Edison, NYSEG/RGE, and O&R, the Company proposes the opportunity to begin earning based on performance for 2017. Rather than filing a separate proposal in addition to the case, the Company filed the 2017 metrics and targets with the rate case. In this way, all parties to the rate case would have an opportunity to evaluate the Company's proposal.

4. Please see Attachment 1 for the workpaper supporting the Benefit Cost Analysis performed by the Company relative to the Gas EE EAM, as shown in Exhibit_(ECP-5), Schedule 9.

Name of Respondent:	Date of Reply:
Lisa Tallet	June 19, 2017

Date of Request: June 20, 2017 | Request No. DPS-379 RAC-8
Due Date: June 30, 2017 | NMPC Req. No. NM-892

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Robert Cully

TO: National Grid, Electric Customer Panel

SUBJECT: **PEAK REDUCTION FROM DER**

Request:
In all interrogatories, all requests for workpapers or supporting calculations shall be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact and unlocked.

1. Explain how the Company developed the MW impacts of the DER listed in its response to DPS-024.

2. With reference to the Company's response to DPS-024, provide the net peak reduction for each DER type at the target level. Explain what the difference between the gross and net MWs from these DERs represents.

3. With reference to the Company's response to DPS-024, provide both the net anticipated peak reduction and gross anticipated peak reduction for each DER type at the minimum level.

4. With reference to the Company's response to DPS-024, provide both the net anticipated peak reduction and gross anticipated peak reduction for each DER type at the maximum level.

5. With reference to the Company's response to DPS-023, provide the weather-normalized NMPC Peak Forecast without Energy Efficiency and Solar PV for each year from 2017 through 2020.

6. With reference to the Company's response to DPS-023, provide the weather-normalized NMPC Peak Historical/Forecast for each year from 2017 through 2020.

7. For each year from 2007 through 2016, provide the historic peak load impact of each DER type listed in the Company's response to DPS-024.

Response:

1. The Company analyzed historic peak impacts and forecast trends to develop peak impact targets for each type of DER listed in the response to DPS-024. The intent was to create targets that were ambitious and that required the Company to deliver performance above historic trends.

    - For Demand Response ("DR"), the Company relied on one year of program history as a reference point and used estimates of potential DR capacity and new customer enrollments to develop a range of minimum to maximum peak impacts.
    - For Solar PV, the Company developed peak impact targets using solar applications in the interconnection queue as a reference, and applying a range of estimates based on the number of projects in the queue at various stages that are forecast to interconnect in a given year, as well as forecast new applications.
    - For Energy Efficiency ("EE"), the Company developed peak impact targets based on forecast ETIP achievements aligned with the incremental EE targets (with the exception of LED streetlights). In determining the targets, the Company had intended to include estimated NYSERDA peak impacts, but discovered in preparing this response that it inadvertently failed to include these estimates. The Company has therefore revised its Peak Reduction targets to include NYSERDA estimated EE and included the revised targets in Attachment 1 and in the tables below. The Company will also submit the revised targets in its Corrections and Updates filing.
    - For VVO, the Company referred to planned VVO investments and used a 2%, 3%, and 3.5% MW reduction estimate for the minimum, target, and maximum targets.
    - For Storage, the Company developed estimates based on the size of potential non-wires alternatives ("NWA") and mandated storage projects. Please refer to Attachment 1 for the spreadsheet used to develop the targets.

2. As seen in Attachment 1, the Company initially designed the peak reduction targets from the bottom up for each type of DER. The total gross peak impacts, however, did not account for forecast peak load growth or provide a means to measure against a constant baseline. Therefore, to create an outcome-based measurement that could be tracked against future peaks, the Company set a baseline and translated the gross MW impacts into net MW impacts that could be measured against the baseline. The difference between the gross and net MW targets represents forecast peak load growth over the baseline. Because the net MW targets represent the aggregate gross impacts netted for forecast load growth, net MW targets are not assumed by DER type. Please see the table below for the peak reduction targets at the target level.

Peak Reduction Targets - Target Level				
	2017	2018	2019	2020
Solar PV	22	58	98	127
Demand response	200	210	220	230
Energy efficiency	51	114	181	248
VVO	0	0	2	4
Storage	2	2	6	8
Gross Peak Targets	275	384	507	616
Forecasted Peak Growth	40	114	178	222
Net Peak Targets	235	271	330	394

3. As mentioned above, because the net MW targets represent the aggregate gross impacts netted for forecast load growth, net MW targets are not assumed by DER type. Please see the table below for the peak reduction targets at the minimum level.

Peak Reduction Targets - Min Level				
	2017	2018	2019	2020
Solar PV	14	33	51	65
Demand response	140	145	150	155
Energy efficiency	44	91	142	193
VVO	0	0	1	2
Storage	0	0	0	0
Gross Peak Targets	198	269	345	416
Forecasted Peak Growth	40	114	178	222
Net Peak Targets	159	155	167	193

4. As mentioned above, because the net MW targets represent the aggregate gross impacts netted for forecasted load growth, net MW targets are not assumed by DER type. Please see the table below for the peak reduction targets at the maximum level.

Peak Reduction Targets - Max Level				
	2017	2018	2019	2020
Solar PV	25	70	120	157
Demand response	300	315	330	345
Energy efficiency	57	131	210	289
VVO	0	0	2	4
Storage	2	5	8	10
Gross Peak Targets	383	520	670	805

Forecasted Peak Growth	40	114	178	222
Net Peak Targets	344	407	492	583
Stretch Net Peak Targets	393	469	566	669

Recognizing the role of market transformation and innovation in achieving success, the Company created stretch goals for the maximum targets to make the targets ambitious. In this case, the net MW targets exceed the anticipated gross impacts of each DER type, assuming that the incremental MW required to achieve the maximum targets may come from new and innovative approaches. The stretch targets were set by moving up the slope of the line between the previous target and maximum. For more detail on how the maximum targets were set, please refer to the "Maximum Targets" tab in Attachment 1.

5. The weather-normalized NMPC Peak Forecast without Energy Efficiency and Solar PV, which adds forecast energy efficiency and solar PV back to the Company's forecast, is as follows:

NMPC Weather-Normalized	**2017**	**2018**	**2019**	**2020**
Peak Forecast without EE & PV	6886	6960	7024	7068

6. The weather-normalized NMPC Peak Forecast, which accounts for the impacts of forecast energy efficiency and solar PV, is as follows:

NMPC Weather-Normalized	**2017**	**2018**	**2019**	**2020**
Peak Forecast	6831	6849	6860	6853

7. Historic peak load impacts from 2007 to 2016 are below. Demand response impacts in 2016 were due to NMPC programs, and prior to 2016 were a result of NYISO calls. Peak impacts due to energy efficiency were not tracked prior to the Energy Efficiency Portfolio Standard ("EEPS"), which began in 2009. Historic peak impacts were not tracked for VVO or storage because there is no VVO and a negligible amount of storage in NMPC.

Historic Incremental Peak Load Impacts										
Peak Impacts (MW)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Solar PV	0.2	0.4	0.7	1.9	3.5	5.9	10.4	17.9	28.1	42.5
Demand response	0.0	0.0	0.0	0.0	0.0	2.0	113.6	0.0	0.0	101.5
Energy Efficiency	0.0	0.0	4.0	35.2	64.7	53.4	40.3	43.6	43.8	44.5

Name of Respondent:
Courtney Eichhorst

Date of Reply:
June 30, 2017

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

The Gas Customer Panel

Dated: July 10, 2017

Q. Please introduce the members of the Gas Customer Panel.

A. The Panel consists of John F. Isberg and James M. Molloy.

Q. Is this the same Panel that submitted testimony previously in this proceeding?

A. Yes. The Panel provided direct testimony as part of the Company's April 28, 2017 filing. The terms defined in the Panel's direct testimony have the same definitions here.

Q. What is the purpose of the Panel's corrections and updates testimony?

A. The purpose of the Panel's testimony is to correct Exhibit ___ (GCP-1), which provides a breakdown of the costs of the Company's proposed non-pipeline alternatives projects. Exhibit ___ (GCP-1CU) is a corrected version of the exhibit that was prepared and compiled under the Panel's supervision and direction.

Q. Please explain the corrected information contained in Exhibit ___ (GCP-1CU).

A. The amount of the incentive per unit and number of units for the Commercial Gas Demand Response Project were transcribed incorrectly in the original exhibit. Exhibit ___ (GCP-1CU) includes the correct information, reflecting a

$400 incentive per unit with forecast units of 1,080 and 1,998 in Data Year 1 and Data Year 2, respectively.

Q. Is there any change to the cost of the Commercial Gas Demand Response Project because of the corrections?

A. No. The corrections merely fix typographical errors. They have no impact on the cost of the proposed project.

Q. Does this conclude the Panel's corrections and updates testimony?

A. Yes, it does.

Exhibits of
The Gas Customer Panel

Index of Exhibits

Exhibit __ (GCP-1CU)

Geothermal Demonstration and DR Pilot

Niagara Mohawk Power Corporation d/b/a National Grid
Gas Customer Panel
Geothermal Demonstation and DR Pilot
($000's)

			FY 2019			FY 2020			FY 2021	
Commercial Gas Demand Response Pilot	Unit Costs	Units	Capital	O&M	Units	Capital	O&M	Units	Capital	O&M
Materials (Devices)	$ 4,000	-	$0	$0	20	$80,000	$0	17	$68,000	$0
Installation Labor & Design	$ 3,000	-	$0	$0	20	$60,000	$0	17	$51,000	$0
Outreach	$ 50,000	1	$0	$50,000	1	$0	$50,000	1	$0	$50,000
Comms	$ 60	-	$0	$0	20	$0	$1,200	37	$0	$2,220
Maintenance/Repair (annual)	$ 250	-	$0	$0	20	$0	$5,000	37	$0	$9,250
Customer Incentives UNY per unit per activation	$ 400	-	$0	$0	1,080	$0	$432,000	1,998	$0	$799,200
Total			$0	$50,000		$140,000	$488,200		$119,000	$860,670

			FY 2019			FY 2020			FY 2021	
Geothermal Demonstration		Units	Capital	O&M	Units	Capital	O&M	Units	Capital	O&M
Below Ground Heat Exchanger:	$ 7,000	100	$0	$700,000	-	$0	$0	-	$0	$0
Above Ground A/C System	$ 3,000	100		$300,000						
Solar Thermal	$ 5,000	20		$100,000						
Project Evaluation		-	$0	$100,000	-	$0	$50,000	-	$0	$0
Total			$0	$1,200,000		$0	$50,000		$0	$0