Addendum to Avoided Energy Supply Costs in New England: 2015 Report

Prepared for:

Avoided-Energy-Supply-Component (AESC) Study Group

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1 Introduction and Summary

In August 2015, the AESC Study Group retained TCR to prepare three supplemental analyses to the Avoided-Energy-Supply-Costs in New England: 2015 Report ("AESC 2015").[1] Chapters 2 through 4 describe each of the three analyses, present their results and explain how Program Administrators (PAs) can apply these results. TCR prepared the analyses described in Chapters 2 and 4 using pCloudAnalytics (pCA) and the dataset for the AESC 2015 Base Case, both of which are described in AESC 2015. As in AESC 2015, all costs are reported in constant 2015 dollars (2015$) except where noted otherwise.

Following is a summary of the analysis and key results in each Chapter.

Chapter 2, Electric Energy Costing Periods.

The "on-peak" period in the ISO New England wholesale energy market is weekdays, excluding certain holidays, is a 16 hour block from 7 a.m. to 11 p.m. However, electric energy use and wholesale energy prices generally peak on weekday afternoons and early evenings during a limited number of summer and winter months. The first task in the supplemental analysis identifies, for each zone, the block of four consecutive hours within the on-peak period during which TCR projects energy prices to most frequently be at their highest. The supplemental analysis then provides average avoided energy costs for these "four-hour on-peak" blocks and for the remaining 12 hours, i.e., the "other on-peak" blocks. This analysis is similar to the identification of "super-peak" hours for the WCMA zone presented in AESC 2015.

Based on the results of its analysis, TCR recommends the following four-hour on-peak periods for avoided electric energy costs:

- For summer months of June through August, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 13:00 to hour ending at 17:00, EDT.
- For winter months of January, February and December, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 17:00 to hour ending at 21:00, EST

Chapter 3. Natural Gas Costing periods.

AESC 2015 presents estimates of avoided costs of natural gas in northern New England (NNE) and southern New England (SNE) by customer sector and end-use load shape, i.e., heating, non-heating and water heating. The second task in the supplemental analysis calculates the projected avoided costs of natural gas in northern New England (NNE) and southern New England (SNE) for three costing periods similar to those used by Vermont. The three periods are peak days (i.e. 10 coldest winter days), shoulder days (i.e., remaining 141 winter season days) and shoulder/summer baseload days (i.e., 214 days). This analysis is similar to the calculation of natural gas avoided costs for Vermont presented in AESC 2015.

If PAs choose to use to apply the avoided gas costs for these three costing periods to load reductions

[1] Hornby, Rudkevich, Schlesinger, Englander, Neri, Goldis, Amoako-Gyan, He, Rivas and Tabors, *Avoided Energy Supply Costs in New England: 2015 Report* Boston, Tabors Caramanis Rudkevich, March 27, 2015 Revised April 3, 2015.

from a particular efficiency program, they will first need to determine the reduction in load from that program in each costing period. PAs could make that determination for a given costing period by multiplying the reduction in gas use per Heating Degree Day (HDD), i.e. MMBtu / HDD, expected in that costing period for the application to which the efficiency program applies by the number of HDD in their service territory in that costing period.

Chapter 4. Assessment of active Demand Response (DR).

AESC 2015 presents estimates of avoided costs and energy price impacts for reductions from potential energy efficiency programs, sometimes referred to as "passive demand response" (PDR). The third task in the supplemental analysis estimates the avoided energy costs and energy price impacts of reductions from potential active DR programs.

Based on the results of its analysis, TCR has the following observations.

- The unit average avoided energy costs of active DR are both DR program-specific and state-specific. Unit average avoided energy costs depend significantly on the key design characteristics of the DR program, their anticipated results and the energy market in which those reductions occur. Key design characteristics and anticipated results include the days on which the DR events occur, the hours on those days during which DR reductions will occur and the size of the reduction in each of those hours.
- The unit average avoided energy cost of active DR targeting reductions in summer hours with the highest load and/or highest energy prices will typically exceed the unit average avoided energy costs in the summer four-hour on-peak period and the summer on-peak period respectively.
- The unit average avoided energy costs of active DR calculated under the realized marginal avoided cost (RMAC) method are consistent with the avoided energy costs reported in AESC 2015. PAs can use the RMAC method to evaluating the cost savings of any DR program by using hourly LMPs from the AESC 2015 Base Case for their state and the projected hours of DR events and anticipated hourly reductions of the specific DR programs being evaluated.
- The unit average avoided energy costs of active DR calculated under the direct avoided cost (DAC) method are the most accurate, but that method requires the use of a simulation model to compare costs under two scenarios, one without the candidate DR and one with the candidate DR. It also requires this simulation analyses for the evaluation of each candidate DR program.
- Active DR does not always cause a reduction in LMPs, which is consistent with the DRIPE results reported in AESC 2015. That fact, combined with the fact that the average avoided energy costs of active DR are DR program-specific and state-specific, highlights the importance of program and state-specific evaluations of potential DR programs. PAs in Connecticut, New Hampshire and Maine should prepare evaluations specific to their states and the potential DR programs under consideration in their states rather than relying solely on the results for Massachusetts presented in this report.

2 Assessment of Alternative Electric Energy Costing Periods

A. Background

AESC 2015, and prior AESC reports, developed projections of avoided energy costs for the summer season and winter season using the on-peak and off-peak time periods in the ISO New England wholesale energy market. ISO New England defines that on-peak period as a 16 hour block, from 7 a.m. to 11 p.m., on weekdays excluding certain holidays. The off-peak period is all remaining hours.

As part of AESC 2015 the Study Group asked the AESC 2015 project team to recommend alternative costing periods for developing avoided electric costs if an analysis indicates that the alternative costing periods may more accurately and reasonably reflect seasonal and hourly variation of marginal energy costs than the existing on-peak and off-peak costing periods. In essence, the goal was to determine if costing periods more granular than on-peak and off-peak would provide a more accurate estimate of the value of reductions which occur primarily during those more granular time periods.

Section 5.7 of the AESC 2015 report presented an analysis of alternative costing periods to the on-peak period. The analysis examined the historical and projected distribution of energy prices by hour in the West Central Massachusetts (WCMA) zone. That analysis identified the four hour block in the on-peak period that most frequently had the highest energy prices in the on-peak period in the summer and winter seasons respectively. AESC 2015 labeled that four hour block as a “super-peak on-peak” period and labeled the remaining 12 hours the “other on-peak” period. Based on those results AESC 2015 recommended that PAs consider using more granular costing periods than the on-peak period, such as the super-peak and other peak periods identified in Section 5.7

In August of 2015, the AESC Study Group asked TCR to perform a supplemental study of more granular costing periods for the on-peak period for each of the New England states. This Chapter summarizes the methodology and findings of this supplemental study.

In the absence of generally accepted terms for these more granular costing periods, the Study Group has asked TCR to use the terms “four-hour on-peak” blocks and “other on-peak” blocks. The four-hour on-peak blocks in each state are the four consecutive hours projected to most frequently have the highest energy prices during the on-peak period each day. The other on-peak blocks are the remaining 12 hours in the on-peak period each day.

Table 1 illustrates the relationship between the on-peak period in the ISO New England wholesale energy market, by season, and the four-hour on-peak and other on-peak periods that TCR has developed in this supplemental analysis.

Table 1 Electric Energy Costing Periods

	ISO-NE (Energy Market)			Avoided Energy Costing Periods (Addendum, AESC 2015)		
Terminology	**Months**	**Time periods (Days and hours)**	**# of hours per year**	**Months**	**Time periods (Days and hours)**	**# of hours per year**
SUMMER						
On-Peak	June – Sept	Non holiday weekdays, 7am – 11 pm	1,382			
Four-hour On-Peak (NOTE 1)				June - August	Non holiday weekdays, 1 pm – 5 pm	260
Other on-Peak				June – Sept	Non holiday weekdays, 7am - 1 pm and 5 pm – 11 pm	1,122
Off-Peak	June – Sept	weekdays, 11 pm – 7 am; all hours Saturday, Sunday, holidays	1,552	Same as ISO - NE		1,552
WINTER						
On-Peak	Oct-May	weekdays, 7am – 11 pm; all hours Saturday, Sunday, holidays	2,787			
Four-hour On-Peak (NOTE 2)				Dec - Feb	Non holiday weekdays, 5 pm – 9 pm	260
Other on-Peak				Oct-May	Non holiday weekdays, 7am – 5 pm and 9 pm – 11 pm	2,527
Off-Peak	Oct-May	weekdays, 11 pm - 7am; all hours Saturday, Sunday, holidays	3,039	Same as ISO - NE		3,039
ANNUAL total			8,760			8,760

Note 1. Summer Four-hour On-Peak period is identical to the ISO –NE "Demand Resource Forecast Peak Hours", the performance period for DR in the FCM

Note 2. Winter Four-hour On-Peak period contains 1 more month (February) than ISO –NE "Demand Resource Forecast Peak Hours", the performance period for DR in the FCM, and 2 more hours per block, i.e., 5 pm – 9 pm vs 5 pm to 7 pm.

B. Methodology

TCR applied the methodology described in Section 5.7 of AESC 2015 to each of the eight Standard Market Design (SMD) Load Zones in New England.

Selection of Four-hour On-Peak Costing Periods

Following the AESC 2015 finding that in summer on-peak period energy prices in June, July and August are consistently higher than September and that winter on-peak prices in December, January and February are consistently higher than in other winter months, TCR selected these months for further analyses.

For each of the eight New England SMD Zones, TCR analyzed five data sets of hourly prices for each of those months, three sets of historical energy prices and two sets of projected energy prices. The historical data sets are from 2012, 2013 and 2014; the projected prices are from the Base Case for June 2019 through May 2020 and for June 2025 to May 2026. For each dataset, TCR computed average prices for each on-peak hour in each of the three summer months and each of the three winter months. For example, for June 2012 TCR computed average hourly prices for each of the 16 on-peak hours, i.e. hours beginning at 07:00 and ending at 23:00 on weekdays.

Next, TCR analyzed energy prices by hour in blocks of four consecutive hours for several different possible blocks in order to identify candidate four-hour on-peak periods by season. For winter months, TCR analyzed the following 4 hour blocks: between hours beginning at 14:00 and ending at 18:00, 15:00 -19:00, 16:00 -20:00 and 17:00 -21:00. For summer months, TCR analyzed the following 4 hour blocks: between hours beginning at 11:00 and ending at 15:00, 12:00 -16:00, 13:00 -17:00 and 14:00 -18:00. Tables 2 through 9 present energy price summaries by source and 4-hour block for all eight SMD Zones.

Table 2**. Average LMP of candidate Four-hour on-peak Periods for the state of Connecticut ($/MWh)**

Winter Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
14:00-18:00	$44.14	$107.67	$139.91	$67.81	$82.32
15:00-19:00	$48.34	$117.10	$152.77	$71.07	$86.74
16:00-20:00	$50.93	$123.14	$161.58	$73.96	$90.26
17:00-21:00	$50.57	$123.75	$162.40	$74.60	$90.85
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$58.74	$57.15	$48.24	$50.79	$70.78
12:00-16:00	$62.52	$59.29	$49.79	$55.01	$75.52
13:00-17:00	$65.31	$60.76	$50.97	$55.21	$79.91
14:00-18:00	$65.06	$60.54	$51.00	$54.79	$79.57

Table 3. **Average LMP of candidate Four-hour on-peak Periods for NMABO ($/MWh)**

Winter Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
14:00-18:00	$43.96	$116.37	$143.52	$68.65	$83.23
15:00-19:00	$47.96	$127.21	$158.08	$72.05	$87.77
16:00-20:00	$50.44	$134.03	$168.19	$75.02	$91.40
17:00-21:00	$49.99	$134.33	$168.96	$75.50	$92.00
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$55.96	$56.44	$48.88	$52.46	$72.13
12:00-16:00	$58.94	$58.75	$50.46	$56.67	$77.04
13:00-17:00	$60.97	$60.19	$51.47	$56.84	$81.41
14:00-18:00	$60.50	$59.79	$51.34	$56.36	$81.00

Table 4. **Average LMP of candidate Four-hour on-peak Periods for SEMA ($/MWh)**

Winter Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
14:00-18:00	$44.13	$116.98	$143.19	$67.48	$82.22
15:00-19:00	$48.13	$127.47	$157.70	$70.72	$86.66
16:00-20:00	$50.61	$133.99	$167.79	$73.52	$90.19
17:00-21:00	$50.19	$134.11	$168.58	$73.99	$90.81
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$56.09	$55.84	$47.61	$50.36	$70.08
12:00-16:00	$59.12	$57.95	$49.07	$54.58	$75.01
13:00-17:00	$61.16	$59.39	$50.15	$54.81	$79.44
14:00-18:00	$60.71	$59.13	$50.08	$54.41	$79.11

Table 5. **Average LMP of candidate Four-hour on-peak Periods for WCMA ($/MWh)**

Winter Blocks	**2012**	**2013**		**2014**	**2019/2020**	**2025/2026**
14:00-18:00	$44.39	$113.27		$142.69	$67.94	$82.49
15:00-19:00	$48.58	$123.10		$156.46	$71.22	$86.91
16:00-20:00	$51.14	$129.39		$165.97	$74.10	$90.43
17:00-21:00	$50.74	$129.72		$166.77	$74.65	$91.02
Summer Blocks	**2012**	**2013**		**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$58.34	$56.52		$48.04	$51.19	$71.00
12:00-16:00	$61.98	$58.62		$49.50	$55.41	$75.83
13:00-17:00	$64.65	$60.05		$50.57	$55.60	$80.21
14:00-18:00	$64.44	$59.79		$50.53	$55.15	$79.84

Table 6. **Average LMP of candidate Four-hour on-peak Periods for the state of Maine ($/MWh)**

Winter Blocks	2012	2013	2014		2019/2020	2025/2026
14:00-18:00	$43.90	$110.71	$135.96		$66.63	$80.02
15:00-19:00	$48.04	$120.84	$150.06		$69.36	$83.99
16:00-20:00	$50.47	$126.95	$159.83		$71.42	$86.83
17:00-21:00	$49.75	$126.87	$160.46		$71.32	$87.17
Summer Blocks	**2012**	**2013**	**2014**		**2019/2020**	**2025/2026**
11:00-15:00	$53.77	$52.57	$45.47		$50.33	$68.79
12:00-16:00	$56.42	$54.39	$46.77		$54.56	$73.46
13:00-17:00	$58.18	$55.59	$47.71		$54.72	$77.55
14:00-18:00	$57.72	$55.30	$47.58		$54.29	$77.06

Table 7. **Average LMP of candidate Four-hour on-peak Periods for the state of New Hampshire ($/MWh)**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026
14:00-18:00	$43.60	$113.11	$141.89	$66.91	$81.62
15:00-19:00	$47.53	$122.97	$156.16	$69.74	$85.56
16:00-20:00	$49.96	$129.12	$166.03	$71.90	$88.43
17:00-21:00	$49.51	$129.24	$166.81	$71.85	$88.73
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$55.79	$55.82	$47.70	$50.65	$69.77
12:00-16:00	$58.64	$57.86	$49.12	$54.87	$74.49
13:00-17:00	$60.55	$59.21	$50.15	$55.03	$78.76
14:00-18:00	$60.04	$58.90	$50.06	$54.60	$78.47

Table 8. **Average LMP of candidate Four-hour on-peak Periods for the state of Rhode Island ($/MWh)**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026
14:00-18:00	$43.51	$118.12	$143.30	$67.66	$82.36
15:00-19:00	$47.38	$128.77	$157.78	$70.93	$86.80
16:00-20:00	$49.76	$135.39	$167.80	$73.76	$90.34
17:00-21:00	$49.37	$135.41	$168.59	$74.23	$90.95
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$56.67	$55.31	$47.25	$50.77	$70.48
12:00-16:00	$59.95	$57.42	$48.70	$54.99	$75.41
13:00-17:00	$62.04	$58.83	$49.77	$55.20	$79.82
14:00-18:00	$61.62	$58.58	$49.70	$54.78	$79.47

Table 9. **Average LMP of candidate Four-hour on-peak Periods for the state of Vermont ($/MWh)**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026
14:00-18:00	$43.58	$110.06	$141.27	$67.26	$81.87
15:00-19:00	$47.45	$119.19	$154.28	$70.20	$85.94
16:00-20:00	$49.89	$125.14	$163.12	$72.49	$88.92
17:00-21:00	$49.46	$125.60	$163.97	$72.62	$89.26
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**
11:00-15:00	$56.44	$56.66	$47.48	$50.94	$70.64
12:00-16:00	$59.27	$58.65	$48.83	$55.16	$75.30
13:00-17:00	$61.16	$59.99	$49.84	$55.33	$79.62
14:00-18:00	$60.66	$59.70	$49.79	$54.90	$79.30

Using this information, for each zone TCR ranked each 4 hour block within each season according to the block's average price of energy by hour during each season. TCR ranked the block with the highest average price 1 and the block with the lowest average price 4. For each time block TCR summed ranks across cases. Finally, using this information for each season TCR identified the block with the lowest total rank. Tables 10 through 17 present ranking results for all SMD zones.

Table 10. **Ranking of candidate four-hour on-peak Periods for the state of Connecticut**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	2	1	1	6
14:00-18:00	2	2	1	3	2	10

Table 11 **Ranking of candidate four-hour on-peak Periods for NMABO**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

Table 12**. Ranking of candidate four-hour on-peak Periods for SEMA**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	2	1	1	6
14:00-18:00	2	2	1	3	2	10

Table 13**. Ranking of candidate four-hour on-peak Periods for WCMA**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

Table 14 **Ranking of candidate four-hour on-peak Periods for the state of Maine**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	1	2	1	2	7
17:00-21:00	2	2	1	2	1	8
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

Table 15**. Ranking of candidate four-hour on-peak Periods for the state of New Hampshire**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	1	2	8
17:00-21:00	2	1	1	2	1	7
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

Table 16**. Ranking of candidate four-hour on-peak Periods for the state of Rhode Island**

Winter Blocks	2012	2013	2014	2019/2020	2025/2026	Total Rank
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

Table 17**. Ranking of candidate four-hour on-peak Periods for the state of Vermont**

Winter Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
14:00-18:00	4	4	4	4	4	20
15:00-19:00	3	3	3	3	3	15
16:00-20:00	1	2	2	2	2	9
17:00-21:00	2	1	1	1	1	6
Summer Blocks	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Total Rank**
11:00-15:00	4	4	4	4	4	20
12:00-16:00	3	3	3	2	3	14
13:00-17:00	1	1	1	1	1	5
14:00-18:00	2	2	2	3	2	11

C. Results and Recommendations

In all zones, the summer block with the best ranking begins at hour 13:00 and ends at 17:00. This block coincides with the summer Demand Resource Forecast Peak Hours defined by ISO-NE.[2]

In all zones except Maine, the winter block with the best ranking begins at 17:00 and ends at 21:00. In Maine, the block between 16:00 and 20:00 has a slightly better ranking than the 17:00 to 21:00 block.

Table 18 summarizes the four-hour on-peak periods for each of the ISO-NE areas based on the ranking results.

Table 18**. Four-hour on-peak periods with best ranking results**

Area	**Summer Blocks**	**Winter Blocks**
CT	13:00-17:00	17:00-21:00
ME	13:00-17:00	16:00-20:00
NH	13:00-17:00	17:00-21:00
RI	13:00-17:00	17:00-21:00
VT	13:00-17:00	17:00-21:00
NMABO	13:00-17:00	17:00-21:00
SEMA	13:00-17:00	17:00-21:00
WCMA	13:00-17:00	17:00-21:00

Although the 16:00 to 20:00 winter block has a better ranking for the Maine zone than the 17:00 to 21:00, TCR analyzed the difference in Four-hour on-peak prices in Maine between these two blocks.

[2] ISO-NE Tariff, Section I – General Terms and Conditions, Definition of Demand Resource Forecast Peak Hours.

This comparison is presented in Table 19. According to this analysis, the differences less than 1%. Thus for uniformity and simplicity across all zones and states TCR recommends using the same Four-hour on-peak winter period of 17:00-21:00 hours

Table 19**. Average winter four-hour on-peak energy prices in Maine using different time blocks ($/MWh)**

Four Hour Block	**2012**	**2013**	**2014**	**2019/2020**	**2025/2026**	**Average**
16:00-20:00	$50.52	$126.03	$158.32	$71.80	$86.84	$98.70
17:00-21:00	$49.80	$125.85	$158.83	$71.69	$87.14	$98.66
Difference (%)	1.43%	0.14%	-0.32%	0.15%	-0.35%	0.04%

Based on the results of this analysis, TCR recommends the following four-hour on-peak periods for avoided electric energy costs:

- For summer months of June through August, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 13:00 to hour ending at 17:00, EDT.
- For winter months of January, February and December, weekdays only (excluding holidays defined by ISO-NE), four hour interval from hour beginning at 17:00 to hour ending at 21:00, EST.

Note that this recommendation is different from the recommendation made in Section 5.7 of the AESC 2015 report where TCR recommended a time period beginning at 16:00 to hour ending at 20:00, EST as the winter Four-hour on-peak period. That recommendation was based on an incorrect processing of price data for WCMA. Correcting for that error resulted in a different ranking and selecting a 17:00 to 21:00 time interval for the winter Four-hour on-peak period.

DRIPE Effects in Four-hour On-Peak and Other Peak Periods

As requested by the study group, TCR also assessed the DRIPE effect for the Four-hour on-peak and other peak periods. In AESC 2015, the DRIPE effect is a product of two components – the energy price and the DRIPE coefficient. The applicable energy prices are computed for four costing periods in each year (summer peak and off-peak, winter peak and off-peak) by aggregating results for the hours in those periods from the BAU simulation for each year. The applicable DRIPE coefficients are computed for the four costing periods using analysis of price differences between the BAU case and specially constructed market simulations with different levels of demand. For each costing period, the DRIPE coefficient is computed as the average for the relevant costing period over a three year horizon 2016 - 2018.

TCR examined the possibility of developing DRIPE coefficients separately for the Four-hour on-peak and other peak periods. That analysis is complicated by the fact that the DRIPE coefficient for the Four-hour on-peak period is highly sensitive to both the magnitude of the demand reduction and the shape of the demand reduction during the four-hour blocks in the Four-hour on-peak period. Thus in order to calculate an accurate DRIPE coefficient for these Four-hour on-peak periods one would need the magnitude and shape of each type of load reduction for which DRIPE results are required. Without accurate information on the load reduction during these time periods the modeling results can be misleading. As a result, TCR does not recommend using separate DRIPE coefficient for Four-hour on-peak and other periods. Instead, TCR calculated DRIPE for the Four-hour on-peak periods and other peak periods by applying the relevant peak period DRIPE coefficients from AESC 2015 to the prices for the Four-hour on-peak periods and other peak periods respectively.

D. Application of Results

TCR developed an avoided cost workbook for Program Administrators (PAs) who are evaluating efficiency measures with reductions the PA can estimate for Four-hour on-peak periods and for other peak periods. A pdf version of the workbook is included as Appendix B to this report. The workbook is a supplement to Appendix B of AESC 2015. The structure of this work book is identical to Appendix B with two exceptions. It provides avoided electric energy costs and energy DRIPE values for four costing periods each year corresponding to On-Peak time periods. The four costing periods are Summer Four-hour on-peak, Summer other on-Peak, Winter Four-hour on-peak and Winter other on-Peak.

A PA should only apply avoided energy cost and energy DRIPE values from the Supplemental workbook if the PA can estimate energy reductions for Four-hour on-peak periods and for other peak period. Under that circumstance, the PA can apply the values as follows:

- For efficiency measures with Summer energy reductions explicitly estimated for summer Four-hour on-peak periods and summer other on-peak periods, use avoided energy cost and energy DRIPE values from the Appendix B Addendum.
- For efficiency measures with Winter energy reductions explicitly estimated for winter Four-hour on-peak periods and winter other on-peak periods, use avoided energy cost and energy DRIPE values from the Appendix B Addendum.
- For efficiency measures with energy reductions in Off-Peak periods in summer or winter, continue using the avoided costs provided in Appendix B for summer off-peak and winter off-peak respectively.

The avoided capacity cost values for reductions in the Four-hour on-peak periods in the Appendix B Addendum are identical to those for on-peak reported in Appendix B. PAs can use these avoided capacity values from either the Appendix B Addendum or from Appendix B.

3 Assessment of Alternative Gas Costing Periods

A. Background

In Task 2 of the Addendum TCR analyzed whether alternative costing period definitions for natural gas may more accurately and reasonably reflect the seasonal variation of marginal energy costs in comparison to the definitions traditionally used for AESC studies. Section 2.16 of the AESC 2015 report presented an analysis of alternative costing periods defined in terms of the major time periods during which natural gas is used, an approach methodologically consistent with the costing periods for calculation of avoided electric energy costs. Based on the results of that analysis AESC 2015 recommended that Program Administrators consider changing the costing periods for natural gas in future AESC studies to three resource based costing periods – peak days (10), shoulder days (141) and baseload days (214).

In August of 2015, the AESC Study Group asked TCR to perform a supplemental study to calculate natural gas avoided costs for those three costing periods. This document summarizes the methodology and findings of this supplemental study.

B. Methodology

TCR applied the methodology described in Section 2.16 of AESC 2015 to develop projections of gas distribution utility avoided natural gas costs for the three costing periods for Southern New England (SNE) and Northern New England (NNE) respectively. (SNE consists of CT, MA and RI; NNE consists of NH and ME). The three costing periods are consistent with the gas industry definitions of winter and summer, i.e. winter is 151 days, November through March, and summer is 214 days, April through October. The two costing periods within the winter, 10 peak days and 141 remaining winter days, are generally consistent with gas distribution supply planning and are also consistent with the costing periods AESC 2015 used in its calculations for Vermont. The projections of marginal costs by costing period were developed from the same updated AESC 2013 projections used to develop the AESC 2015 gas distribution utility avoided natural gas costs.

C. Results and their Application

Table 20 and Table 21 report the resulting values in 2015$/MMBtu by year from 2015 through 2045 for SNE and NNE respectively. These values include an adjustment for the AESC 2015 assumed distribution system loss of 2%, but do not assume any retail margin. As such, the results in Table 20 and Table 21 are comparable to the values reported in AESC Exhibits C-1 and C-3 respectively. TCR developed an avoided cost workbook for PAs who wish to evaluate gas efficiency measures using these three costing periods. A pdf version of the workbook is included as Appendix C to this report

If a PA wished to apply the avoided gas costs for these three costing periods to load reductions from a particular efficiency program, it would first need to determine the reduction in load from that program in each costing period. PAs could make that determination for a given costing period by multiplying the reduction in gas use per Heating Degree Day (HDD), i.e. MMBtu / HDD, expected in that costing period for the application to which the efficiency program applies by the number of HDD in their service territory in that costing period.

For example, the reductions in load in each costing period from an efficiency program in Massachusetts targeted at residential heating would be as follows:

- Reduction on peak days = expected reduction in residential heating gas use per HDD (MMBtu / HDD) on coldest 10 days of year * HDD in MA on coldest 10 days of year.

- Reduction on baseload days Reduction on shoulder days = expected reduction in residential heating gas use per HDD (MMBtu / HDD) on shoulder days * HDD in MA on shoulder days

- Reduction on baseload days = expected reduction in residential heating gas use per HDD (MMBtu / HDD) on baseload days * HDD in MA on baseload days.

Once a PA has projected load reductions from a particular efficiency program for each costing period, the PA can multiply the load reduction in each costing period by the avoided gas supply cost for each costing period from Table 20 or Table 21 according to the state in which the PA is located. If, in addition, the PA wished to calculate the avoided retail margin for that particular efficiency program, the PA could multiply the total load reduction for all three costing periods by the avoidable LDC margins from Exhibit 2-43 of AESC 2015 for the relevant sector, end-use and state.

Table 20 Avoided Cost of Gas by Costing Period, Southern New England

Avoided Cost of Gas to Retail Customers by Costing Period - Southern New England (CT, MA, RI), 2015$ per MMBtu			
Assumes 2% Distribution System Losses and zero Avoidable Retail Margin			
(2015$ per MMBtu)			
Costing period	**Shoulder / summer**	**Remaining Winter**	**Peak Days**
Days	**214**	**141**	**10**
Year			
2015	$ 4.45	$ 6.39	$ 10.91
2016	$ 4.66	$ 6.67	$ 8.47
2017	$ 5.36	$ 7.68	$ 9.68
2018	$ 5.84	$ 8.18	$ 10.36
2019	$ 5.89	$ 8.20	$ 10.62
2020	$ 5.53	$ 7.77	$ 10.19
2021	$ 5.83	$ 8.20	$ 10.81
2022	$ 5.91	$ 8.28	$ 10.97
2023	$ 6.00	$ 8.38	$ 11.12
2024	$ 6.19	$ 8.69	$ 11.60
2025	$ 6.31	$ 8.80	$ 11.77
2026	$ 6.41	$ 8.96	$ 12.03
2027	$ 6.49	$ 9.05	$ 12.18
2028	$ 6.60	$ 9.16	$ 12.32
2029	$ 6.80	$ 9.35	$ 12.51
2030	$ 7.08	$ 9.63	$ 12.79
2031	$ 7.08	$ 9.63	$ 12.79
2032	$ 7.08	$ 9.63	$ 12.79
2033	$ 7.08	$ 9.63	$ 12.79
2034	$ 7.08	$ 9.63	$ 12.79
2035	$ 7.08	$ 9.63	$ 12.79
2036	$ 7.08	$ 9.63	$ 12.79
2037	$ 7.08	$ 9.63	$ 12.79
2038	$ 7.08	$ 9.63	$ 12.79
2039	$ 7.08	$ 9.63	$ 12.79
2040	$ 7.08	$ 9.63	$ 12.79
2041	$ 7.08	$ 9.63	$ 12.79
2042	$ 7.08	$ 9.63	$ 12.79
2043	$ 7.08	$ 9.63	$ 12.79
2044	$ 7.08	$ 9.63	$ 12.79
2045	$ 7.08	$ 9.63	$ 12.79
Levelized (a)			
2016-2025	$5.72	$8.05	$10.50
2016-2030	$6.00	$8.40	$11.05
2016-2045 (b)	$6.44	$8.90	$11.76

Table 21 Avoided Cost of Gas by Costing Period, Northern New England

Avoided Cost of Gas to Retail Customers by Costing Period - Northern New England (NH, ME), 2015$ per MMBtu			
Assumes 2% Distribution System Losses and zero Avoidable Retail Margin			
(2015$ per MMBtu)			
Costing period	**Shoulder / summer**	**Remaining Winter**	**Peak Days**
Days	**214**	**141**	**10**
Year			
2015	$ 4.12	$ 7.69	$ 10.91
2016	$ 4.64	$ 8.42	$ 8.47
2017	$ 5.70	$ 9.33	$ 9.68
2018	$ 5.98	$ 9.78	$ 10.36
2019	$ 5.86	$ 13.68	$ 10.62
2020	$ 5.48	$ 13.30	$ 10.19
2021	$ 5.78	$ 13.67	$ 10.81
2022	$ 5.87	$ 13.77	$ 10.97
2023	$ 5.95	$ 13.88	$ 11.12
2024	$ 6.14	$ 14.13	$ 11.60
2025	$ 6.24	$ 14.24	$ 11.77
2026	$ 6.35	$ 14.38	$ 12.03
2027	$ 6.44	$ 14.49	$ 12.18
2028	$ 6.54	$ 14.60	$ 12.32
2029	$ 6.73	$ 14.79	$ 12.51
2030	$ 7.01	$ 15.07	$ 12.79
2031	$ 7.01	$ 15.07	$ 12.79
2032	$ 7.01	$ 15.07	$ 12.79
2033	$ 7.01	$ 15.07	$ 12.79
2034	$ 7.01	$ 15.07	$ 12.79
2035	$ 7.01	$ 15.07	$ 12.79
2036	$ 7.01	$ 15.07	$ 12.79
2037	$ 7.01	$ 15.07	$ 12.79
2038	$ 7.01	$ 15.07	$ 12.79
2039	$ 7.01	$ 15.07	$ 12.79
2040	$ 7.01	$ 15.07	$ 12.79
2041	$ 7.01	$ 15.07	$ 12.79
2042	$ 7.01	$ 15.07	$ 12.79
2043	$ 7.01	$ 15.07	$ 12.79
2044	$ 7.01	$ 15.07	$ 12.79
2045	$ 7.01	$ 15.07	$ 12.79
Levelized (a)			
2016-2025	$5.74	$12.29	$10.50
2016-2030	$6.00	$12.99	$11.05
2016-2045 (b)	$6.41	$13.84	$11.76

4 Assessment of Demand Response Avoided Costs for Electric Energy

A. Background

In Task 3 TCR estimated the impact of active Demand Response (active DR) on locational marginal prices (LMPs) for three Massachusetts zones (NEMA – Boston, SEMA, and WCMA) as well as for Connecticut, Maine, New Hampshire and Rhode Island over the period 2016 – 2018.

The AESC Study Group agreed that TCR would limit its analysis to LMPs and energy costs, i.e., TCR would not analyze impacts on capacity prices or avoided capacity costs. The AESC Study Group also agreed that TCR would prepare the analyses using the same *pCloudAnalytics* energy market model and input data for the ISO New England system as it used to prepare the AESC 2015 Base Case.[3]

The initial scope of work (SOW) for this task assumed that members of the AESC Study Group from each state would provide TCR with key details of the active DR they wanted TCR to analyze for their state for the period 2016 – 2018. Those key details were expected to include:

1. DR profiles by state or SMD Zone. (A profile could be thought of as an aggregation of DR programs that share the same trigger rules).
2. The trigger rule by profile by state by year (e.g. system-wide or SMD Zone demand in excess of specified threshold).
3. The size, hourly shape of demand reduction (in MW) of the profile when it is triggered. This information should be provided by profile by state or SMD zone.
4. The duration or a termination rule of the demand reduction event provided in the most unambiguous way (e.g. profile will persist for 6 hours, or profile will persist as long as the system or SMD Zone demand remains above the threshold, or whichever condition ends last, etc.). This information should be provided by profile by state or SMD zone
5. The size, hourly shape and duration (in MW) of the snapback effect associated with each demand reduction event by profile by state or SMD Zone.

Based upon that assumption TCR proposed to run seven DR scenarios, one for each state in which the DR is assumed to be in place in that state only and one scenario for all states in which all DR profiles are assumed to be in place in all states.

During the course of the task, with approval of the project manager, TCR modified its analytical approach relative to that in the SOW in three respects. First, TCR only ran a DR scenario for MA, since it was the only state for which TCR received adequate quantitative information on active DR programs under consideration that would yield material reductions. For that DR Scenario, which we also refer to

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[3] In AESC 2015 TCR simulated the operation of the ISO NE wholesale energy market under a Base Case which assumed no approval of new efficiency programs from 2016 onward.

as the MA DR Load Reduction Case, TCR simulated the operation of the ISO NE wholesale energy market using the load reductions for each day provided by National Grid. Second, TCR ran that DR scenario as a decrement cases since the quantitative information for DR in MA and RI was limited to the hours in which DR reductions occurred and the size of the reductions in each hour. Third, TCR expanded its analyses to calculate the avoided energy costs of DR using two different methodologies.

The remaining sections describe the active DR that TCR assessed, the methodologies TCR used to assess the avoided costs of those active DR reductions and their results, and the methodologies TCR used to assess the price impacts of those active DR reductions and their results.

B. Characteristics of Active DR

Active DR has a more narrow focus than passive DR, or energy efficiency. The primary goal of active DR is typically to reduce electricity use just during hours of highest peak demand and/or during hours of highest energy prices. The Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) define DR as:

> *Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*[4]

That definition reflects the potential of DR to cause changes in electric use in order to maintain system reliability, in order to avoid high energy prices, or some combination of both factors.

National Grid and TCR discussed various approaches for evaluating possible active DR programs National Grid might offer in MA and RI over the period 2016 – 2018. They ultimately agreed that TCR would provide National Grid hourly LMPs for the months of June through August in 2016 through 2018 from the AESC 2015 Base Case and National Grid would develop projections of the operation of their various potential DR programs during that period. National Grid provided TCR the results of its projections consisting of the hours in which it projected DR reductions would occur and the corresponding projection of the aggregate reduction from the portfolio of potential DR programs in each of those hours. Table 22 reports summary statistics for the projected DR events from the NGRID portfolio of potential DR programs for MA and RI.

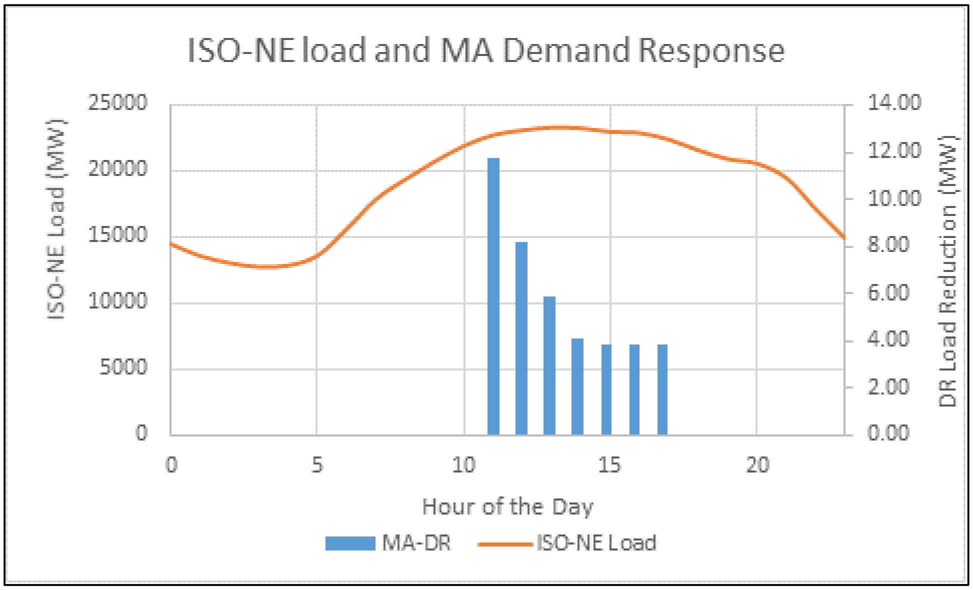
[4] ____, *Assessment of Demand Response Potential and Advanced Metering*, FERC, February 2011, page 21.

Table 22. Summary of Assumed DR Reductions in MA and RI

Year	2016	2017	2018
Massachusetts			
DR events (days)	22	21	19
Average Duration per event (hr)	7.00	7.90	8.32
Max Duration (hr)	14	14	14
Min Duration (hr)	1	1	1
Average Demand Reduction per event (MW)	2.720	15.246	18.583
Max Reduction (MW)	5.707	45.823	50.628
Min Reduction (MW)	1.753	3.834	4.235
Rhode Island			
DR events (days)	22	21	19
Average Duration per event (hr)	7.00	7.90	8.32
Max Duration (hr)	14	14	14
Min Duration (hr)	1	1	1
Average Demand Reduction per event (MW)	0.072	0.389	0.449
Max Reduction (MW)	0.160	0.678	0.986
Min Reduction (MW	0.043	0.182	0.076

The projected MA DR load reduction in 2016 is much smaller than the reductions projected for 2017 and 2018 because 2016 is the first year of their potential programs. The projected MA DR load reduction in 2016 is 2.7 MW on average and ranges between 1.7 MW and 5.7 MW. The 2018 and 2019 average demand reduction levels are 15.2 MW and 18.6 MW, respectively, a significant increase from the 2016 level. The assumed duration of DR events in MA ranges from 1 hour to 14 hours. The clients project the average duration of DR events in MA to increase from 7 hours in 2016 to 8.3 hours in 2018. Figure 1 shows a typical load reduction profile for a projected DR event in MA based on an event projected for June 20, 2017.

Figure 1. DR load reduction profile in Massachusetts and ISO New England system demand



National Grid specified that the reductions from the DR programs under consideration would be dispatchable. In other words, the System Operator would have the ability to treat these reductions as predictable resources when making its decisions regarding Day-ahead Unit Commitments and when dispatching units during the "day of" actual electric energy use. The fact that National Grid is evaluating DR that is dispatchable, rather than non-dispatchable, is a key characteristic. That distinction determines the type of impact the DR will have on energy prices in the short-term and on the need for capacity in the long-term.

The effect of dispatchable DR on unit commitment has important implications for the resulting impacts on energy costs and capacity costs. As discussed in AESC Chapter 5, and in Appendix A to this report, under its unit commitment process ISO-NE begins making its decisions regarding which units to commit to serving load on a given day well in advance of that day. ISO NE bases its decisions on which units to commit, or schedule, on several factors. One key factor is the set of units that are currently committed, i.e. the set of units it is starting from to serve the projected day ahead load. A second key factor is the total projected day ahead load, because the goal of the ISO NE unit commitment decision is to minimize the total production cost of serving the day ahead load over the entire 24 hour period. That total production cost includes not only the variable cost of production from each unit but also the costs of starting-up each unit and the operational constraints on using each unit. For example, our simulations indicate that DR load reductions in certain hours on a given day change the size and shape of the on-peak period load sufficiently to cause a change in unit commitment under which peaking units run more hours and combined cycle unit run fewer hours. In turn, because of that change in unit commitment, total production costs for the entire day are lower but LMPs during that day could be higher.

C. Avoided Costs for Electric Energy from Active DR

TCR used two metrics to estimate the energy cost savings of DR: realized marginal avoided energy costs

(RMAC) and direct avoided energy costs (DAC). RMAC and DAC are alternative metrics or measures of the energy cost savings of DR. Program Administrators (PAs) can use either RMAC or DAC, but not both.

The calculation of RMAC uses LMPs from the AESC 2015 Base Case as a measure of unit avoided energy cost. As such, the RMAC assumes DR reductions do not cause any change in unit commitment. In addition, the RMAC measures only the marginal variable cost of production as reflected in the LMP; it does not reflect the impact of demand reduction on start-up costs or on the costs related to operational constraints due to minimum up- or down- time of generators. A key advantage of the RMAC metric is that PAs can calculate it using hourly LMPs from the AESC 2015 Base Case. PAs can also calculate the RMAC metric after the fact using ex post market data by multiplying actual demand reduction quantities in each hour by actual LMPs reported by the ISO New England.

TCR calculated DAC as the difference in system-wide total generation production costs between two scenarios, a scenario with no DR (AESC 2015 Base Case) and a scenario with DR (state-specific DR Scenario). As a result, the calculation of DAC reflects the impact of DR reductions on unit commitment and thereby reflects the changes in variable costs of production, start-up costs and costs associated with operational constraints. TCR calculated the system-wide generation production costs under each scenario using *pCloudAnalytics* (pCA) to simulate the operation of the New England energy market under each scenario. DAC can only be calculated by comparing the simulation model results for two scenarios.

Realized Marginal Energy Avoided Cost.

Methodology

The RMAC of a DR event in a given hour equals the demand reduction in that hour multiplied by the appropriate LMP in that hour. The energy cost saving of DR is therefore equals:

$$CstSav_{RMAC}(YY, MM) = \sum_{h \in HH(YY,MM)} DR(h) \times LMP(h) \qquad (1)$$

where $CstSav_{RMAC}(YY, MM)$ is the DR cost savings accrued during month MM of year YY and measured using marginal avoided costs $LMP(h)$ multiplied by hourly demand reduction $DR(h)$; and $HH(YY, MM)$ represent a set of all hours during month MM and year YY. The corresponding realized marginal avoided cost $RMAC(YY, MM)$ equals

$$RMAC(YY, MM) = \frac{CstSav_{RMAC}(YY, MM)}{\sum_{h \in HH(YY,MM)} DR(h)} \qquad (2)$$

In other words, the realized marginal avoided energy cost of the DR measure is a ratio of the DR cost savings over the total demand reduction, or an average LMP weighted by demand reduction.

To calculate DR cost savings based on marginal avoided costs, TCR simply used hourly values of marginal avoided costs produced by the pCA model for the AESC 2015 study. TCR used formulas (1) and (2) to calculate the RMAC for DR reductions in Massachusetts and Rhode Island based upon the relevant LMPs for each state and the hourly demand reductions National Grid provided for each state.

Results

Table 23 and Table 24 summarize RMAC DR cost savings for Massachusetts and Rhode Island, respectively. These tables also present a comparison of realized avoided costs with summer on-peak and summer four-hour on-peak avoided costs.

Table 23. RMAC DR Cost Savings for Massachusetts

		2016	2017	2018	Average
A	DR Cost Saving	$48,102	$204,407	$204,622	$152,377
B	Load Reduction (MWh)	419	2,531	2,936	1,962
C = A/B	DR RMAC ($/MWh)	$114.82	$80.76	$69.70	$77.67
	Summer Four-hour on-peak ($/MWh)	$69.84	$80.50	$59.21	$69.85
	Summer On-Peak ($/MWh)	$47.79	$49.24	$48.12	$48.39
	DR RMAC over Four-hour on-peak ($/MWh)	64%	0%	18%	11%
	DR RMAC over On-Peak ($/MWh)	140%	64%	45%	61%

Table 24. RMAC DR Cost Savings for Rhode Island

		2016	2017	2018	Average
A	DR Cost Saving	$1,239	$5,775	$4,582	$3,866
B	Load Reduction (MWh)	11.1	64.5	70.9	48.8
C = A/B	DR RMAC ($/MWh)	$111.59	$89.54	$64.61	$79.14
	Summer Four-hour on-peak ($/MWh)	$68.98	$79.78	$58.62	$69.13
	Summer On-Peak ($/MWh)	$46.97	$48.55	$47.59	$47.70
	DR RMAC over Four-hour on-peak ($/MWh)	62%	12%	10%	14%
	DR RMAC over On-Peak ($/MWh)	138%	84%	36%	66%

The results in Table 23 and Table 24 demonstrate that DR reduction weighted unit average avoided energy costs in summer hours, reported on line c, exceed the corresponding hourly average avoided costs for the Summer Four-hour on-peak period from Chapter 2 and for the Summer On-Peak period from AESC 2015. Over the 2016 to 2018 period, the DR RMAC for MA reported in row C exceeds Summer Four-hour on-peak average by 11% and the Summer On-Peak average by 61%. In Rhode Island, the DR RMAC exceeds the Summer Four-hour on-peak average by 14% and the Summer On-Peak average by 66%.

The top-half of Table 25 illustrates why the DR RMAC in 2016 is much higher than in 2017 and 2018, both in MA and RI. The DR RMAC reported in the Tables are “reduction load weighted” average values, i.e., the more reductions that occur in high price hours the higher the RMAC. Using Massachusetts as an example, the 2016 DR RMAC is $114.82/MWh as compared to $80.76 and $69.70 in 2017 and 2018 respectively. The high DR RMAC in 2016 is due to that fact that 2016 is a start-up year with a low quantity of reductions. Of the total reductions in 2016, 5.7% occur in hours with LMPs equal to or greater than $1,000/MWh. In contrast, in 2017 and 2018 when the DR programs are fully deployed and yielding much greater reductions, less than 1% of those reductions occur in hours with LMPs equal to or greater than $1,000/MWh.

The bottom half of Table 25 indicates that the simple average avoided energy costs for the DR Event periods exceed the corresponding simple average avoided costs for the Summer Four-hour on-peak period from Chapter 2 and for the Summer On-Peak period from AESC 2015 by even larger percentages than the DR RMAC. The simple average avoided energy costs for the DR Event periods provides an "apples to apples" comparison since the averages for the summer four-hour and on-peak periods are also simple averages.

Table 25. MA DR Reductions and Event Hours in hours with LMPs above and below $1,000/MWh

DR RMAC (reduction weighted)	**2016**	**2017**	**2018**
% of DR reduction at LMP at $1,000 or greater (%)	5.71%	0.85%	0.14%
% of DR reduction at LMP less than $1,000 (%)	94.29%	99.15%	99.86%
DR RMAC (reduction weighted) $/MWh	$ 114.83	$ 80.75	$ 69.71
Summer Four-hour on-peak $/MWh	$ 69.84	$ 80.50	$ 59.21
DR RMAC (reduction weighted) over Summer four-hour on-peak	64%	0%	18%
DR simple Average Avoided Cost	**2016**	**2017**	**2018**
% hours in which DR reductions occur at LMP at $1,000 or greater	7.14%	3.01%	0.63%
% hours in which DR reductions occur at LMP at less than $1,000	92.86%	96.99%	99.37%
DR simple Average Avoided Cost $/MWh	**$ 131.82**	**$ 96.67**	**$ 69.99**
Summer Four-hour on-peak $/MWh	$ 69.84	$ 80.50	$ 59.21
DR simple Average Avoided Cost vs Summer four-hour on-peak	**89%**	**20%**	**18%**

It is important to note that RMACs are program and state specific. They cannot be generically applied to any DR program. Instead, for each DR program as designed, the program developer should use the projected hourly LMPs applicable to the projected load reduction profile of the program to evaluate the cost savings of the program. The PA can identify applicable LMPS based on the program design and the hours in which the DR program will reduce demand.

In response to a client request, TCR prepared illustrative calculations of RMAC for Connecticut, Maine and New Hampshire based upon the hourly AESC 2015 Base Case LMPs for each respective state and the projected MA DR event hours and load reductions. (TCR applied the projected MA DR reductions in each of the other states, i.e., TCR did not scale the projected MR DR reductions in proportion to the loads in each of those states relative to the load in MA). Table 26 through Table 28 present the results of these calculations

Table 26. Illustrative RMAC DR Cost Savings for Connecticut per CT LMPs and MA DR data

	2016	2017	2018	Average
DR Cost Saving	$47,536	$201,366	$200,945	$149,949
Load Reduction (MWh)	419	2,531	2,936	1,962
DR RMAC ($/MWh)	$113.49	$79.56	$68.44	$76.43
Summer four-hour on-peak ($/MWh)	$69.32	$80.20	$58.64	$69.39
Summer On-Peak ($/MWh)	$47.01	$48.58	$47.60	$47.73
DR RMAC over four-hour on-peak ($/MWh)	64%	-1%	17%	10%
DR RMAC over On-Peak ($/MWh)	141%	64%	44%	60%

Table 27. Illustrative DR Cost Savings for Maine per ME LMPs and MA DR data

	2016	2017	2018	Average
DR Cost Saving	$47,262	$199,172	$199,120	$148,518
Load Reduction (MWh)	419	2,531	2,936	$1,962
DR RMAC ($/MWh)	$112.83	$78.70	$67.82	$75.70
Summer four-hour on-peak ($/MWh)	$68.46	$79.30	$58.23	$68.66
Summer On-Peak ($/MWh)	$46.56	$48.17	$47.31	$47.35
DR RMAC over four-hour on-peak ($/MWh)	65%	-1%	16%	10%
DR RMAC over On-Peak ($/MWh)	142%	63%	43%	60%

Table 28. Illustrative DR Cost Savings for New Hampshire per NH LMPs and MA DR data

	2016	2017	2018	Average
DR Cost Saving	$47,529	$200,975	$200,825	$149,776
Load Reduction (MWh)	419	2,531	2,936	$1,962
DR RMAC ($/MWh)	$113.47	$79.41	$68.40	$76.34
Summer four-hour on-peak ($/MWh)	$68.91	$79.68	$58.52	$69.04
Summer On-Peak ($/MWh)	$46.87	$48.44	$47.51	$47.61
DR RMAC over four-hour on-peak ($/MWh)	65%	0%	17%	11%
DR RMAC over On-Peak ($/MWh)	142%	64%	44%	60%

Direct Avoided Energy Cost

Methodology

The DAC of a DR event equals the difference in system-wide generation production costs between two scenarios, a scenario with no DR (Base Case) and a scenario with state-specific DR (DR Scenario). The hourly demand in the state-specific DR Scenario is derived from the AESC 2015 Base Case by decreasing the Base Case hourly demand for that state in accordance with the state-specific DR load reduction profile. All other modeling inputs to the state specific DR scenario are identical to those of the Base Case. TCR simulates the entire New England electric energy market under both scenarios.

The Direct Avoided Cost is

$$CstSav_{DAC}(YY, MM) = \sum_{h \in HH(YY,MM)} (GenPC_{BC}(h) - GenPC_{DR}(h)) \quad (3)$$

Where $CstSav_{DAC}(YY, MM)$ is the DR cost saving accrued during month MM of year YY and measured using the difference in generation production costs $GenPC_{BC}(h), GenPC_{DR}(h)$ under the Base Case and DR Case, respectively. The corresponding direct avoided cost $DAC(YY, MM)$ equals

$$DAC(YY, MM) = \frac{CstSav_{DAC}(YY, MM)}{\sum_{h \in HH(YY,MM)} DR(h)} \quad (4)$$

Results

Direct Avoided Costs equal the difference between system-wide generation production costs under the DR Scenario and the Base Case. Table 29 reports the annual DAC results for Massachusetts.

Table 29. DAC DR Cost Savings for Massachusetts

	2016	2017	2018	Average
Direct Avoided Costs - total	\$30,565	\$449,721	\$174,682	\$218,323
Demand Reduction (MWh)	419	2,531	2,936	1,962
Direct Avoided Costs - per unit (\$/MWh)	\$72.95	\$177.66	\$59.50	\$111.27

It is important to note that the MA DR reductions TCR modelled for the period June through August of 2016 to 2018 represent a tiny per cent of the New England system wide load projected for that period. As indicated in Table 30, the average annual MA DR reduction of 1,962 MWh represents 0.005% of the projected system wide load in the corresponding period. The DAC resulting from that reduction is 0.025% of the projected system wide generation production costs in the corresponding period. However, by targeting the highest energy price hours, reductions from active DR do have a disproportionate impact. As indicated in the table, there is a 4.8% reduction in generation production costs for every 1% reduction in load during DR event hours.

TCR did not calculate DAC for Rhode Island because the magnitude of the projected DR reductions provided by National Grid, which ranged between 0.044 MW and 0.986 MW, was simply too small to perform a robust simulation.

Table 30 MA DR reductions and DAC vs ISO system-wide load and generation production costs, June-August 2016 - 2018

Formula	Components	Total for 2016 thru 2018, June July & August	Average for 2016 thru 2018, June July & August
ISO NE system wide load,			
a	Base Case (MWh)	110,955,303	36,985,100.93
b	MA DR Reduction scenario (MWh)	110,949,417	36,983,139.02
c = a - b	DR Reduction (MWh)	5,886	1,962
d = c / a	DR Reduction (%)	0.0053%	**0.0053%**
ISO NE system wide generation production costs			
e	Base Case	$ 2,566,385,932	$ 855,461,977
f	MA DR Reduction scenario	$ 2,565,730,963	$ 855,243,654
g = e - f	DAC ($)	$ 654,969	$ 218,323
h = g / e	DAC (%)	0.0255%	**0.0255%**
% reduction in generation production costs for every % reduction in total load			**4.8**

Discussion of RMAC and DAC results

Our major observations from the RMAC and DAC results are outlined below.

First, unit average avoided energy costs of active DR are both DR program-specific and state-specific. Unit average avoided energy costs depend significantly on the key design characteristics of the DR program, their anticipated results and the energy market in which those reductions occur. Key design characteristics and anticipated results include the days on which the DR events occur, the hours on those days during which DR reductions will occur and the size of the reduction in each of those hours.

Second, the unit average avoided energy cost of active DR targeting reductions in summer hours with the highest load and/or highest energy prices will typically exceed the unit average avoided energy costs in the summer four-hour on-peak period and the summer on-peak period respectively.

Third, the unit average avoided energy cost of active DR calculated using the RMAC method are consistent with the calculation of avoided energy costs in AESC 2015. PAs can use the RMAC method to evaluating the cost savings of any DR program by using hourly LMPs from the AESC 2015 Base Case for their state and the projected hours of DR events and anticipated hourly reductions of the specific DR programs being evaluated. TCR will provide a workbook PAs can use to calculate the RMAC of potential active DR programs.

Fourth, the DAC method provides the most accurate estimate of the cost saving resulting from the reductions of a specific DR program, or the aggregate reductions from a specific portfolio of candidate DR programs, as long as those reductions are evaluated in isolation assuming that "everything else remain equal." However, if a PA wishes to evaluate a number of different possible DR programs, it may be more difficult to apply the DAC method because the choice of a Base Case becomes more complicated. Does one continue to use the Base Case with no DR in every calculation, or does one begin using a reference case equal to the Base case plus some level of DR reduction. In that type of evaluation there may be no clear advantage of using the direct method over relying on marginal avoided costs. Moreover, PAs cannot easily use the DAC method to evaluate the cost savings of any DR program since DAC can only be calculated by comparing the simulation model results for two scenarios, one without the candidate DR and one with the candidate DR.

Finally, the unit average avoided energy cost of active DR calculated using the DAC method are different from those calculated using the RMAC approach. A year-by-year comparison of the DAC results for Massachusetts in Table 29 and the corresponding RMAC results in Table 23 shows significant difference between these two measures of DR energy cost savings. This comparison shows that the unit DAC may exceed the unit RMAC in one year but be significantly lower in another year. The differences between the two sets of estimates arise from the following two key factors:

- RMAC savings are based upon an approximation of marginal avoided costs that assume the DR reductions do not cause any change in unit commitment. In contrast, the DAC savings are based upon differences in generation production costs that do reflect the change in unit commitment caused by DR reductions.
- RMAC savings reflect only the change in variable cost of generation production whereas DAC savings reflect the change in variable cost of production plus the change in start-up costs.

Thus, the estimate of DAC savings is significantly more complex. As explained in Appendix A, because decisions regarding unit commitment are forward looking, and because those decisions result in unit commitments that can last several days, the reduction in generation production costs caused by DR reductions may occur not just, or even, during the hours of the DR event but instead may also occur either prior to or after those hours. Moreover, the reduction in generation production costs during those hours can be followed by an increase in production costs in subsequent hours which diminish the effect of the initial reduction in production costs. Our modelling has identified examples of the latter impacts in August of 2017 and August of 2018 as plotted in Figures 4 and 5 of Appendix A.

Application of RMAC results

TCR provided the Study Group the workbook with its calculations of the RMAC by state reported in Tables 23 through 28. TCR also provided the Study Group a workbook (*AESC 2015 Add RMAC calculation* *template.xls)* which PAs can use to calculate the RMAC of potential active DR programs in June, July and August of 2016 through 2018. PAs can calculate the RMAC by using the sheet for their state and entering the projected hourly reductions of the specific DR programs they wish to evaluate.

D. Impact of Active DR on Energy Prices

Method

The Energy Price Impacts of DR are comparable in concept to the Demand Reduction Induced Price Effect (DRIPE) calculated in AESC 2015. The Energy Price Impact metric measures the change in electricity prices attributable to the reduction in load from DR. TCR measured the energy price impact of the MA DR reductions as the difference in LMPs between the Base Case and the MA DR scenario.

In AESC 2015 TCR used pCA to develop the projected LMPs for the Base Case.[5] TCR also used pCA to project LMPs under the MA DR scenario. (As noted earlier, TCR did not prepare a Rhode Island DR scenario because the projected DR reductions for Rhode Island were too small to support a robust simulation.) TCR used the same configuration and dataset as the AESC 2015 Base Case except for the hourly load. To construct the load for the MA DR scenario TCR started with the hourly loads for MA from the Base Case and reduced those loads for DR events using the DR profiles for Massachusetts National Grid provided in September 2015.

Results

Table 31 summarizes the impact of DR on LMPs in Massachusetts, expressed in $/MWh. It presents the difference in MA LMPs between the Base Case Scenario and the MA DR Scenario, i.e. Base Case LMP minus DR Scenario LMP, in the months of each year in which the MA DR load reductions occur, i.e., June, July and August. It presents these differences for the entire day (24 hours) of the reductions as well as for the on-peak periods and the off-peak periods. Negative differences indicate that MA DR resulted in a reduction in energy prices relative to the Base Case, positive differences indicate that MA DR resulted in an increase in energy prices relative to the Base Case. (Note that the totals reported for each time period are averages for the three months).

[5] See Chapter 5 of the AESC 2015 study for details of the *pCloudAnalytics* system used in that study, input data sources and modeling assumptions underlying the Base Case scenario.

Table 31. Impact of DR on LMPs in MA relative to Base Case ($/MWh)

Period	Month	2016	2017	2018
24hr	June	(0.19)	(0.03)	0.33
24hr	July	0.21	(0.02)	0.07
24hr	August	0.20	1.88	2.07
24hr Total		0.07	0.62	0.83
OffPeak	June	(0.16)	0.03	0.26
OffPeak	July	0.21	(0.01)	0.05
OffPeak	August	0.14	(0.54)	0.73
OffPeak Total		0.07	(0.17)	0.35
OnPeak	June	(0.15)	(0.06)	(0.12)
OnPeak	July	(0.02)	(0.05)	(0.01)
OnPeak	August	0.09	4.87	3.09
OnPeak Total		(0.02)	1.66	1.04

Table 32 presents these impacts on LMPs expressed as percentage changes up or down.

Table 32 Impact of DR on LMPs in MA relative to Base Case (%)

Period	Month	2016	2017	2018
24hr	June	-0.49%	-0.05%	0.69%
24hr	July	0.46%	-0.05%	0.15%
24hr	August	0.50%	4.65%	5.02%
24hr Total		0.18%	1.35%	1.83%
OffPeak	June	-0.47%	0.08%	0.62%
OffPeak	July	0.68%	-0.03%	0.13%
OffPeak	August	0.49%	-1.54%	2.01%
OffPeak Total		0.22%	-0.47%	0.89%
OnPeak	June	-0.32%	-0.11%	-0.24%
OnPeak	July	-0.04%	-0.08%	-0.02%
OnPeak	August	0.18%	10.94%	6.97%
OnPeak Total		-0.04%	3.12%	2.08%

Discussion of Energy Price Impact results

The results in Table 31 indicate that dispatchable active DR does not always cause a reduction in LMPs even though it causes a reduction in total production costs as reported in Table 29. DAC DR Cost Savings for Massachusetts. These results are consistent with the DRIPE results reported in AESC 2015. For example, the Table reports positive differences in LMPs in August 2017 and August 2018, indicating that the average daily LMPs in Massachusetts were approximately 5% higher under the DR Scenario than under the Base Case in those two months. The MA DR reductions in early August of each of those years caused changes in unit commitments that resulted in lower production costs in each of those months, as reported in Table 33 in Appendix A, but higher LMPs during each August.

A reduction in demand during a given hour of a given day, or during a block of hours on a given day, does not always result in a corresponding reduction in the LMPs in that hour or block of hours for the reasons presented in AESC 2015 Section 7.2.2. In short, there is not a simple linear relationship between the energy load in a given hour of a given day and the LMP in that hour. Instead, the relationship between load in a given hour of a given day and the LMP in that hour is affected by the load by hour anticipated for that entire day, fuel prices on that day and unit availability on that day.

This complex relationship is due to the unit commitment process discussed in section B of this Chapter, in Appendix A to this report and in AESC Chapter 5. As explained in section B, under its unit commitment process ISO-NE begins making its decisions regarding which units to commit to serving load on a given day well in advance of that day with the goal of minimizing the total production cost of serving the day ahead load over the entire 24 hour period. That total production cost includes not only the variable cost of production from each unit but also the costs of starting-up each unit and the operational constraints on using each unit. As a result, under a scenario in which the system operator has the ability to use dispatchable DR load reductions as a resource to change the size and shape of the on-peak period load, the system operator may choose a unit commitment that is different from a scenario under which it does not have that DR resource. Under the DR scenario the system operator may choose a unit commitment under which peaking units run more hours and combined cycle unit run fewer hours. The system operator would be achieving lower total production costs under the unit commitment for that DR scenario, but LMPs could be higher.

The fact that active DR may not always cause a reduction in LMPs, combined with the fact that the average avoided energy costs of active DR are DR program-specific and state-specific, highlights the importance of program and state-specific evaluations of potential DR programs. PAs in Connecticut, New Hampshire and Maine should prepare evaluations specific to their states and the potential DR programs under consideration in their states rather than relying solely on the results for Massachusetts presented in this report.

Appendix A.

Modeling Unit Commitment in the Wholesale Energy Market

The process through which the system operator, in New England it is ISO NE, schedules individual generating units to be run in a given hour of a given day, or not run in that hour of that day, is referred to as "unit commitment".

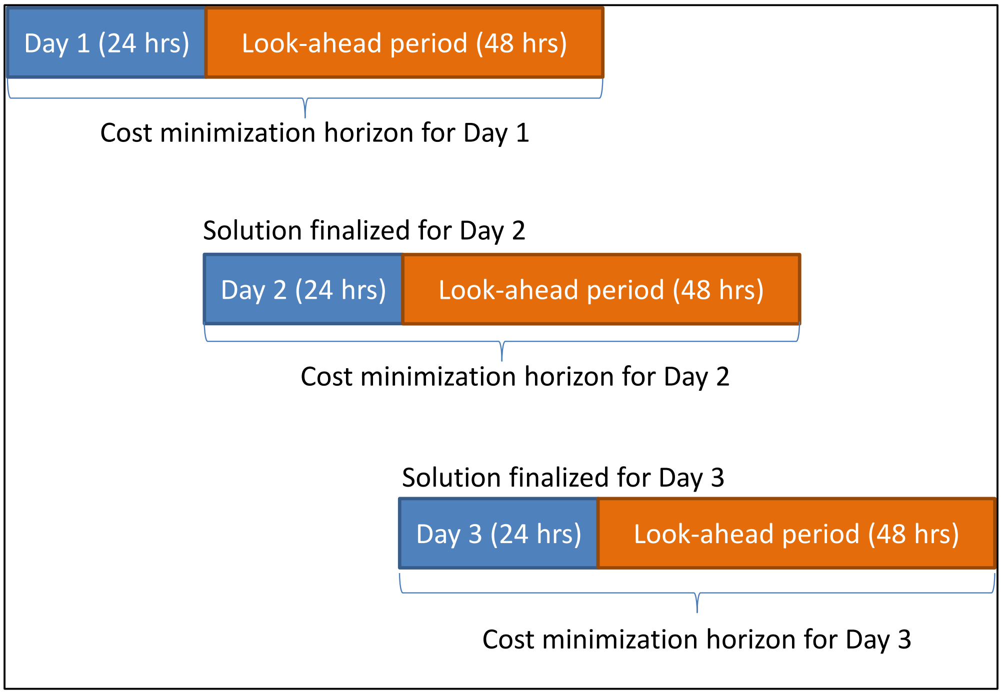
Unit commitment is related to, but different from, economic dispatch and occurs on a different timeframe. System operators begin making unit commitment decisions for a given day several days in advance of that day, and continue to refine those decisions until a few hours prior to the actual time of electricity use. In contrast, system operators make decisions about dispatching units, i.e., economic dispatch decisions, in close to real-time, e.g., on a minute by minute basis.

The goal of the unit commitment decision is find the least-cost mix of units to supply energy for the 24 hours period for which the decision is being made, plus at least another 24 hours of the look-ahead time to correctly assess the future implications of decisions made for the first 24 hours. Thus, ISO NE is making unit commitment decisions for a 24 hour period, not a 1 hour period. ISO NE makes unit commitment decisions for each unit based on the unit's operational constraints in addition to the load to be served and the economics of the unit. The operational constraints include minimum up- and down-times, minimum operating limits, and start-up costs

ISO NE produces unit commitment decisions by solving advanced algorithms of the mixed integer linear programming problem. In formulating and solving this problem, ISO NE considers not only fuel and variable O&M costs submitted by generation owners though supply offers, but also start-up costs and opportunity costs associated with running energy limited resources such as hydro and pumped storage resources. This problem is essentially a dynamic optimization problem with economic and operational considerations spanning over 24 hours of the day for which the problem is being solved plus at least another 24 hours of the look-ahead time to correctly assess the future implications of decisions made for the first 24 hours. The solution to this problem is sensitive to the level of load that the power system is projected to serve.

TCR models these unit commitment decisions, and the resulting price formation in wholesale electric energy markets, using the rolling horizon optimization approach depicted in Figure 2.

Figure 2. Rolling Horizon Modeling of the New England Market



In AESC 2015 and in this supplemental study, to simulate ISO NE's unit commitment decisions, TCR used a 72-hour optimization horizon. Once the optimization is completed, the resulting unit commitment decisions for the first 24 hours are considered final whereas the resulting unit commitment decisions for the next 48 hours are treated as provisional. The unit commitment decisions for hours 25 – 48 will be finalized on the next day and for hours 49 – 72 – on the day after.

This rolling horizon optimization approach has important implications for evaluation of the type of dispatchable DR resources that NGRID is considering. In summary, the effect of dispatchable DR resources on total energy production costs on a given day is never limited to the day on which the DR load reduction occurs.

- The effect of the DR event can begin up to two days before the start of the DR event. If the system operator expects to use the DR resource on Day 3, it will appear in the optimization problem the system operator solves for Day 1 and thus may influence unit commitment decisions made for Day 1 and for Day 2.
- The impact of the event may last for several days after the event. Unit commitment decisions for a given day or set of days have lasing implications for subsequent days. A change in the unit commitment decision for a given day will typically result in changes in the start times and shut-down times of generating units which have minimum up- and down- time constraints.
- The savings in production costs resulting from the demand reduction may not necessarily occur on the day of the demand reduction event. The savings in production costs could also occur on days before the day of the DR event or could be "planned" to occur after the event. However,

cost savings planned for after the event can be over-ridden by decisions made on the next day, for example, in anticipation of the subsequent demand reduction event.

Overall, the relationship between demand reduction events and costs savings can become very complex as shown by the modeling results for the summers of 2016 through 2018 plotted in Figure 3 through

Figure 5. In AESC 2015 TCR simulated the operation of the ISO NE wholesale energy market under a Base Case which assumed no approval of new efficiency measures from 2016 onward. In Task 3 of this Addendum TCR simulated the operation of the ISO NE wholesale energy market under a MA DR Load Reduction Case using the load reductions for each day provided by National Grid. The load reductions provided by National Grid are from dispatchable DR programs and occur in June, July and August of 2016 through 2018 respectively.

Table 33 presents the change in total production costs for each of these months between the Base Case and the MA DR Load Reduction Case. As indicated in the Table, the load reductions from dispatchable DR caused a reduction in total production costs in each of these months.

Table 33 Change in Total Production Costs by Month under MA DR Load Reduction Case

Impacts of MA DR relative to Base Case	Time Period	Month	2016	2017	2018
Change in ISO NE total Production Costs, i.e., DAC results, $	month	June	$ (17,151)	$ (12,208)	$ (5,009)
		July	$ (6,484)	$ (183,793)	$ (159,571)
		August	$ (6,930)	$ (253,721)	$ (10,103)
	June to August total		$ (30,565)	$ (449,721)	$ (174,682)

The changes in production costs by month reported in Table 33 are aggregations of the changes in production costs by day in each of those months. Figures 3 to 5 plot those changes in production costs by day in each month of 2016, 2017 and 2018 respectively. The Figures also plot the changes in load in Massachusetts on those days. The black bars in these figures plot the MA DR reductions (MWh) in daily demand, whose values are reported on the right vertical axis. (Days on which the DR reduction is zero, i.e., no DR reduction, appear as black dots on the x axis). The blue line plots the change in ISO NE generation production costs each day whose values are reported on the left vertical axis. Negative production costs represent reductions in production costs relative to the Base Case while positive production costs represent increases relative to the Base Case.

Figure 3. Summer 2016: Change in MA Demand vs. Change in Total Production Costs

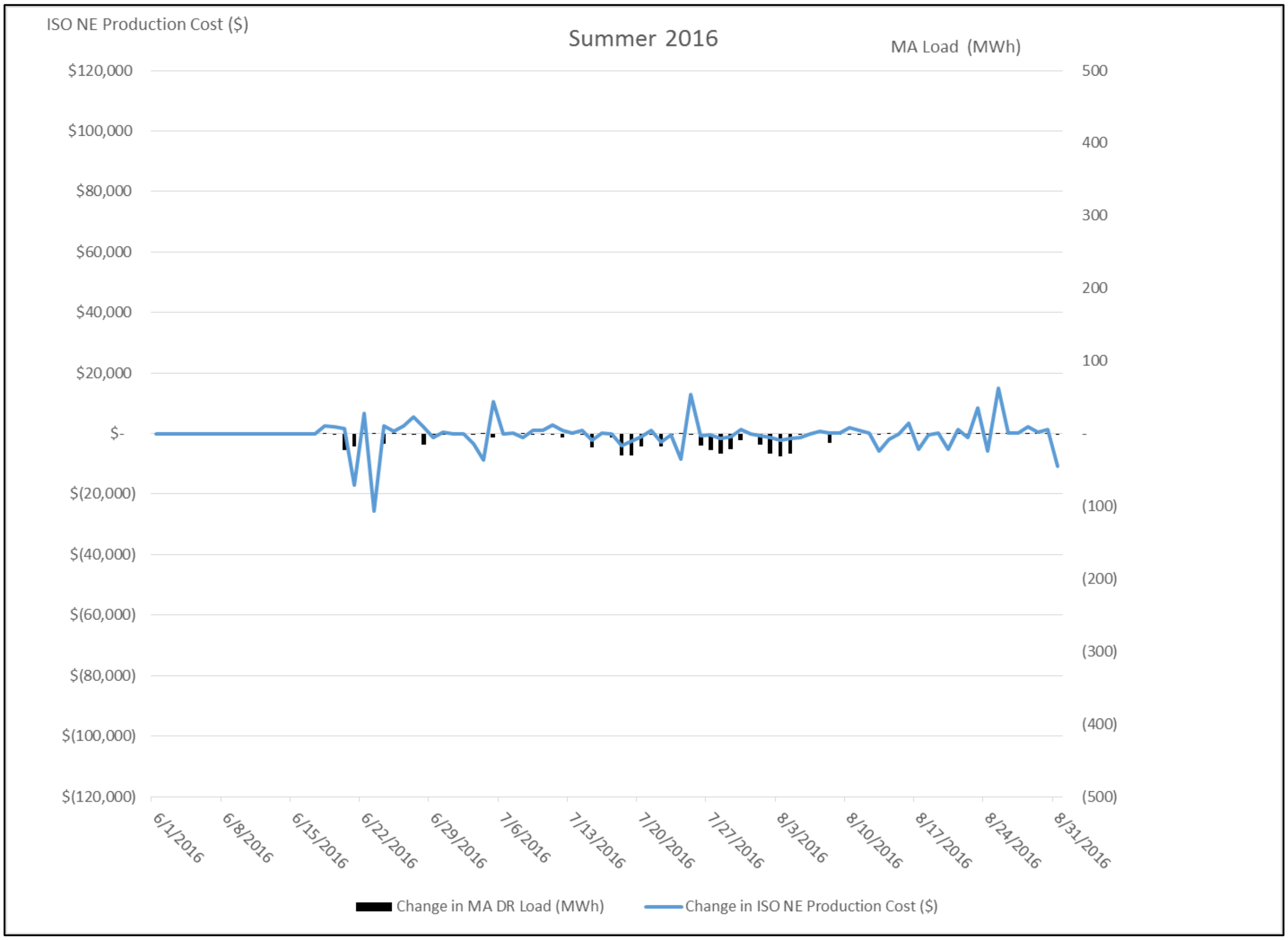


Figure 4. Summer 2017: Change in MA Demand vs. Change in Total Production Costs

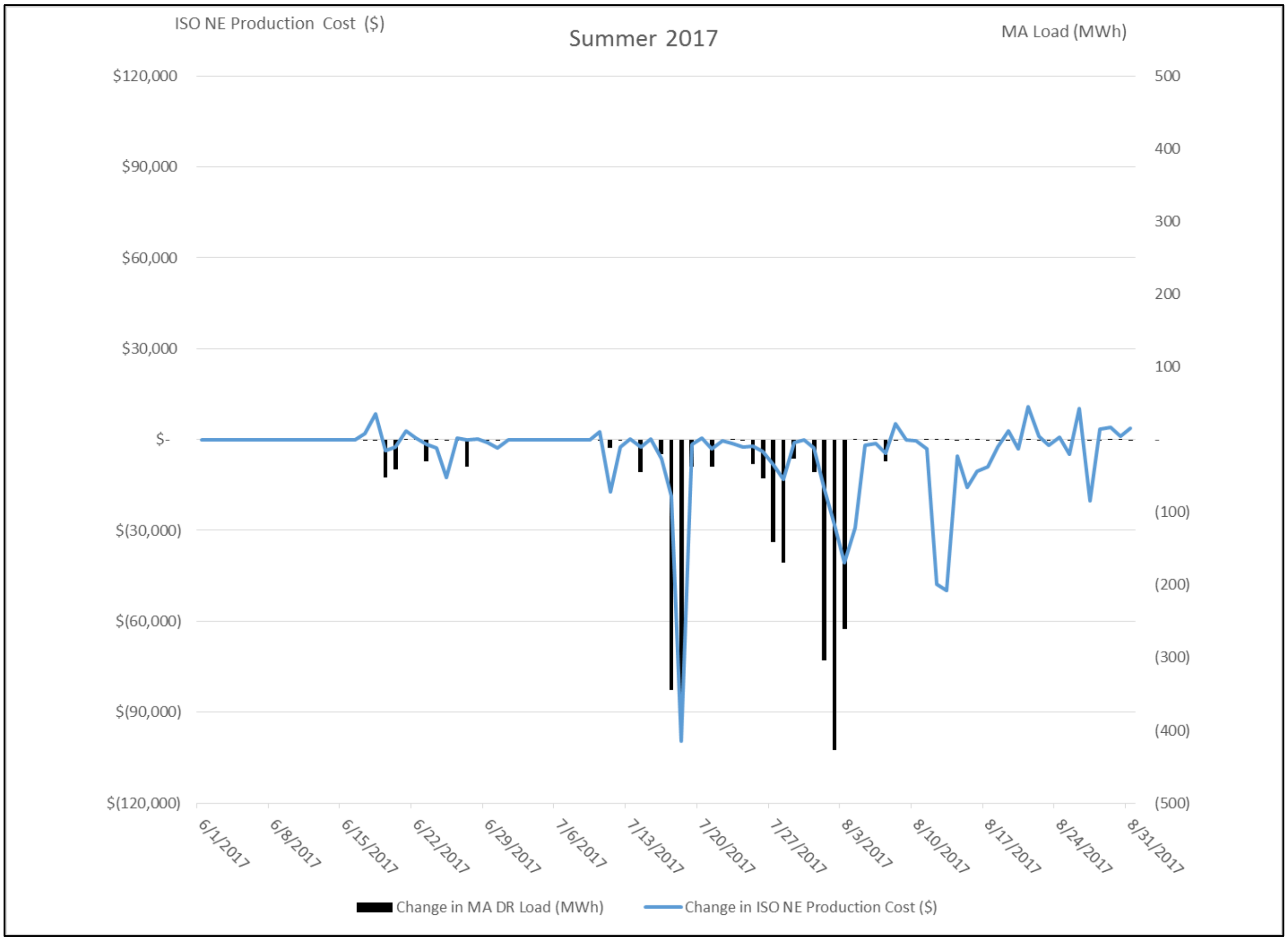
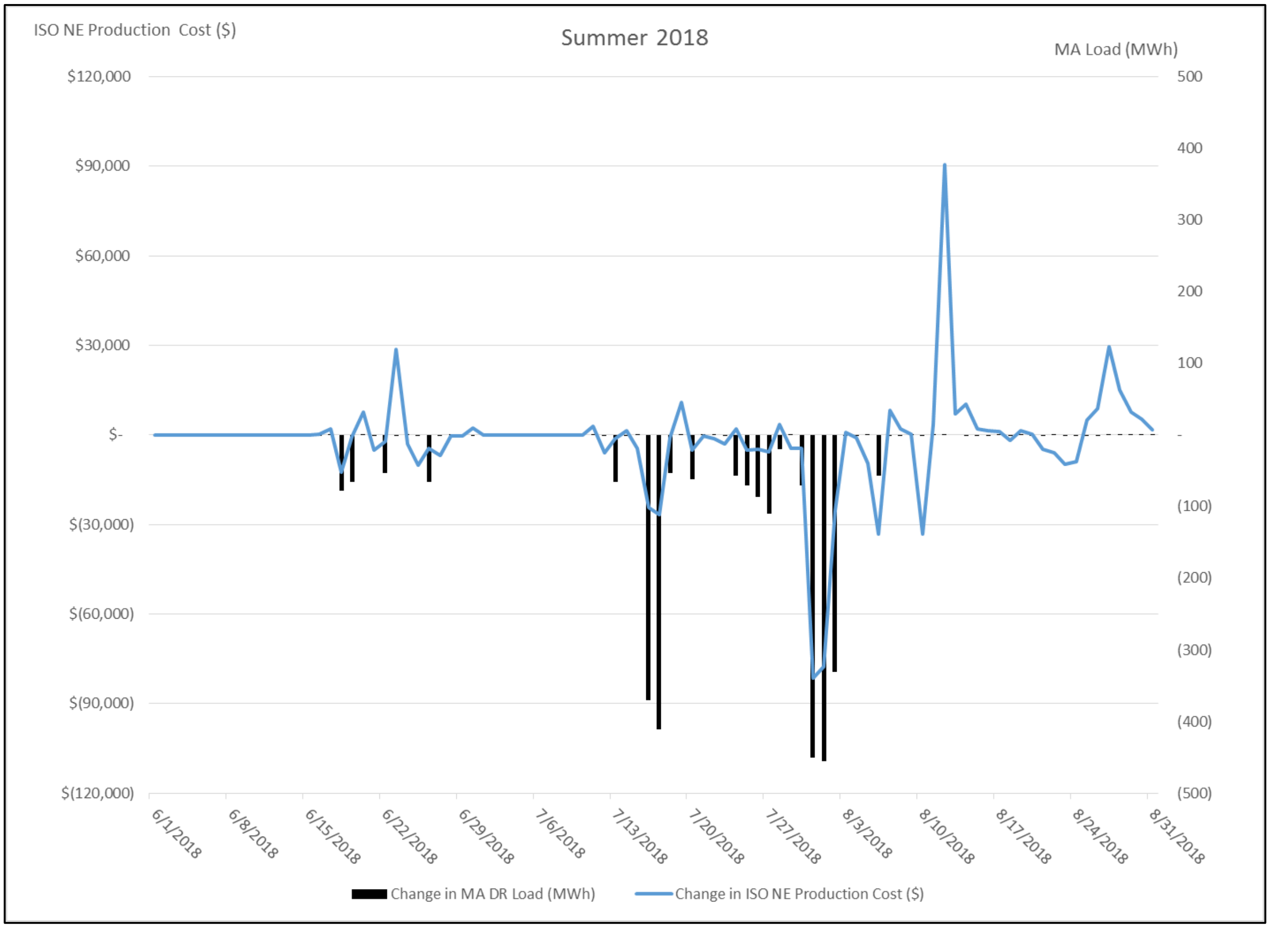


Figure 5.Summer 2018: Change in MA Demand vs. Change in Total Production Costs



Figures 3 to 5 indicate that although the load reductions from dispatchable DR cause aggregate reductions in total production costs in each of these months, those load reductions do not cause a reduction in total production costs on every day of those months. These figures clearly illustrate the complexity of the relationship between changes in demand due to reductions from a portfolio of dispatchable DR programs and the resulting changes in generation production costs due to changes in unit commitment. For example, in Figure 4 the load reductions from the portfolio of dispatchable DR programs on a few days in early August of 2017 result in a reductions in ISO NE generation production costs by day in mid-August 2017 and increases by day later in August 2017. In Figure 5, the load reductions in early August of 2018 result in a series of decreases and increases in ISO NE generation production costs by day throughout the remainder of August.2018. This complexity is behind the volatile behavior of avoided costs presented in Chapter 4.

The series of decreases and increases in ISO NE generation production costs by day throughout the remainder of August.2018 illustrate how a change in unit commitment due to load reductions from dispatchable DR on a few days early in a month can have a compounding effect over the remainder of the month. Table 34 presents the changes in energy production by day and the corresponding changes in total production cost by day in August 2018 under the MA DR Case as compared to the Base Case.[6] The Table presents these results by major category of generating unit, i.e., steam generating units (ST), pumped storage (PSH), gas combined cycle (CC) and gas turbine peakers (GT). Over the course of the month, under the MA DR Load Reduction Case, more generation was provided from gas turbines, steam units and pumped storage and less from combined cycle units.

[6] The change in production costs corresponding to the change in PSH generation is reflected in the changes in production costs of the other categories of generating units. The total change in production costs does not reconcile exactly with the total for August 2018 reported in Table 33 because we did not compile very minor changes in production costs of certain units.

Table 34. Change in Generation and in Production Costs by Category by Day, MA DR Case – Base Case[7]

August 2018	Change in System-Wide Generation (MWh), MA DR Case - Base Case					Change in System-Wide Production Costs, MA DR Case - Base Case			
	PSH	ST	CC	GT	Total	ST	CC	GT	Total
1	-20	-618	36	147	-455	($89,262)	$1,627	$9,867	($77,768)
2	-15	-867	46	506	-331	($60,834)	$2,349	$33,142	($25,343)
3	0	-0	-0	-0	0	$22	$920	$5	$948
4	-0	0	-0	-0	0	($215)	($817)	$27	($1,005)
5	-4	0	4	-0	0	$33	($9,650)	$29	($9,588)
6	1,066	-115	-42	-967	-58	($3,970)	$15,657	($45,001)	($33,313)
7	1,206	-38	-1,167	0	0	($1,230)	$9,500	($36)	$8,234
8	0	-19	75	-55	0	($704)	$4,795	($1,957)	$2,135
9	-40	-289	352	-23	0	($9,080)	$10,017	($835)	$102
10	1,161	-77	642	-1,727	0	($2,344)	$51,672	($82,662)	($33,334)
11	-38	14	-27	51	0	$692	$993	$1,813	$3,498
12	-1,723	153	-1,904	3,473	0	$5,420	($100,150)	$185,238	$90,508
13	0	472	-506	34	0	$16,751	($11,102)	$1,077	$6,726
14	31	57	-24	-64	0	$1,496	$11,249	($2,273)	$10,472
15	-11	0	11	-0	0	$277	$1,601	($79)	$1,799
16	0	81	-84	2	0	$2,924	($1,555)	$73	$1,442
17	0	0	0	-0	0	$243	$906	$1	$1,151
18	1,099	-115	-984	0	0	($3,751)	$1,906	($31)	($1,876)
19	0	0	-286	286	0	($378)	($12,463)	$14,297	$1,456
20	0	-2	0	2	0	$22	$158	$136	$315
21	-8	22	7	-21	0	$647	($4,914)	($715)	($4,981)
22	2	338	-363	24	0	$11,113	($18,059)	$790	($6,155)
23	-81	0	81	0	0	$255	($10,181)	($49)	($9,974)
24	-583	686	-204	101	0	$22,421	($34,887)	$3,537	($8,929)
25	154	0	-158	4	0	$552	$4,161	$64	$4,777
26	190	0	-223	33	0	$52	$7,977	$826	$8,854
27	-1,599	584	-812	1,827	0	$19,128	($75,601)	$85,966	$29,493
28	26	380	-433	26	0	$12,582	$1,480	$839	$14,901
29	0	0	0	-0	0	$1,278	$6,201	($64)	$7,414
30	-17	413	-428	32	0	$13,541	($9,263)	$1,122	$5,400
31	-228	115	108	5	0	$4,255	($2,646)	$100	$1,708
Total	**569**	**1,173**	**-6,283**	**3,697**	**-844**	**($58,063)**	**($158,118)**	**$205,248**	**($10,932)**

[7] Shaded rows are days in August 2018 with reductions in load from MA DR, i.e. August 1, 2 and 6.

Table One: Avoided Cost of Electricity (2015 $) Results : CT Connecticut

State CT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1412	0.0835	0.0713	0.0479														0.0478	0.0478	0.0509	0.0509
2016	0.1320	0.0768	0.0851	0.0544	41.2	*0.0*	20.6	0.0111	0.0061	0.0043	0.0025							0.0473	0.0473	0.0504	0.0504
2017	0.1277	0.0751	0.0974	0.0580	123.7	*0.0*	61.8	0.0107	0.0059	0.0050	0.0027		0.0107	0.0059	0.0050	0.0027		0.0469	0.0469	0.0500	0.0500
2018	0.0883	0.0662	0.0743	0.0595	143.6	*0.0*	71.8	0.0071	0.0051	0.0036	0.0028		0.0071	0.0051	0.0036	0.0028		0.0466	0.0466	0.0497	0.0497
2019	0.0871	0.0665	0.0711	0.0603	133.2	*0.0*	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0908	0.0649	0.0785	0.0591	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0883	0.0666	0.0778	0.0618	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0976	0.0719	0.0863	0.0663	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0984	0.0727	0.1002	0.0676	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.1022	0.0745	0.0871	0.0702	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1100	0.0775	0.0976	0.0745	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1083	0.0787	0.1100	0.0755	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1010	0.0802	0.0910	0.0761	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1010	0.0812	0.1015	0.0787	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1104	0.0854	0.1060	0.0828	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1252	0.0918	0.1470	0.0947	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1295	0.0948	0.1536	0.0987	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1339	0.0980	0.1604	0.1030	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1385	0.1012	0.1676	0.1074	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1432	0.1046	0.1751	0.1121	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1481	0.1081	0.1830	0.1170	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1532	0.1117	0.1912	0.1222	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1585	0.1155	0.1999	0.1275	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1639	0.1194	0.2089	0.1332	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1696	0.1235	0.2184	0.1391	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1755	0.1276	0.2283	0.1452	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1815	0.1320	0.2387	0.1517	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1879	0.1365	0.2496	0.1585	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1944	0.1412	0.2610	0.1656	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.2012	0.1460	0.2729	0.1730	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2082	0.1510	0.2854	0.1808	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.1026	0.0712	0.0853	0.0628	132.9	111.9	122.4	0.0031	0.0019	0.0014	0.0009	0.0000	0.0020	0.0012	0.0009	0.0006	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1045	0.0748	0.0928	0.0682	140.7	140.1	140.4	0.0022	0.0013	0.0010	0.0006	0.0000	0.0014	0.0009	0.0007	0.0004	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1287	0.0929	0.1404	0.0949	148.1	167.6	157.8	0.0013	0.0008	0.0006	0.0004	0.0000	0.0008	0.0005	0.0004	0.0003	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

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Zone: CT

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1211	0.0682	0.0570	0.0356			39.7	17.0%	0.0084								
2016	0.1124	0.0617	0.0693	0.0411	0.0227	0.0144	38.2	17.0%	0.0088	0.0054	0.0040	0.0024	0.0000				
2017	0.1080	0.0597	0.0802	0.0441	0.0136	0.0087	114.5	17.0%	0.0092	0.0052	0.0046	0.0025	0.0000	0.0052	0.0046	0.0025	0.0000
2018	0.0716	0.0513	0.0586	0.0451	0.0063	0.0042	132.9	17.0%	0.0095	0.0045	0.0034	0.0026	0.0000	0.0045	0.0034		
2019	0.0702	0.0513	0.0555	0.0456	0.0040	0.0027	123.3	17.0%	0.0097								
2020	0.0734	0.0497	0.0622	0.0444	0.0040	0.0027	135.8	17.0%	0.0099								
2021	0.0719	0.0521	0.0623	0.0476	0.0006	0.0006	138.6	17.0%	0.0090								
2022	0.0784	0.0548	0.0680	0.0497	0.0006	0.0006	139.9	17.0%	0.0112								
2023	0.0797	0.0562	0.0813	0.0514	0.0006	0.0006	137.7	17.0%	0.0106								
2024	0.0837	0.0582	0.0698	0.0542	0.0006	0.0006	140.6	17.0%	0.0101								
2025	0.0916	0.0617	0.0801	0.0590	0.0006	0.0006	143.5	17.0%	0.0094								
2026	0.0906	0.0634	0.0922	0.0605	0.0006	0.0006	144.1	17.0%	0.0087								
2027	0.0846	0.0655	0.0754	0.0618	0.0006	0.0006	142.7	17.0%	0.0081								
2028	0.0852	0.0670	0.0856	0.0647	0.0006	0.0006	146.2	17.0%	0.0075								
2029	0.0933	0.0704	0.0892	0.0680	0.0006	0.0006	151.9	17.0%	0.0080								
2030	0.1074	0.0767	0.1273	0.0793	0.0006	0.0006	153.5	17.0%	0.0075								
2031	0.1113	0.0795	0.1334	0.0831	0.0006	0.0006	147.0	17.0%	0.0075								
2032	0.1153	0.0824	0.1397	0.0870	0.0006	0.0006	147.0	17.0%	0.0075								
2033	0.1195	0.0854	0.1463	0.0911	0.0006	0.0006	147.0	17.0%	0.0075								
2034	0.1239	0.0885	0.1532	0.0954	0.0006	0.0006	147.0	17.0%	0.0075								
2035	0.1284	0.0917	0.1604	0.0999	0.0006	0.0006	147.0	17.0%	0.0074								
2036	0.1331	0.0951	0.1680	0.1046	0.0006	0.0006	147.0	17.0%	0.0074								
2037	0.1380	0.0986	0.1759	0.1096	0.0006	0.0006	147.0	17.0%	0.0074								
2038	0.1430	0.1021	0.1843	0.1148	0.0006	0.0006	147.0	17.0%	0.0074								
2039	0.1482	0.1059	0.1930	0.1202	0.0006	0.0006	147.0	17.0%	0.0074								
2040	0.1536	0.1097	0.2021	0.1259	0.0006	0.0006	147.0	17.0%	0.0074								
2041	0.1592	0.1137	0.2116	0.1318	0.0006	0.0006	147.0	17.0%	0.0074								
2042	0.1650	0.1179	0.2216	0.1380	0.0006	0.0006	147.0	17.0%	0.0074								
2043	0.1710	0.1222	0.2321	0.1446	0.0006	0.0006	147.0	17.0%	0.0073								
2044	0.1772	0.1266	0.2431	0.1514	0.0006	0.0006	147.0	17.0%	0.0073								
2045	0.1837	0.1312	0.2546	0.1585	0.0006	0.0006	147.0	17.0%	0.0073								
Levelized Costs																	
10 years (2016-2025)	0.0845	0.0556	0.0685	0.0479	0.0058	0.0038	123.0		0.0097	0.0016	0.0013	0.0008	0.0000	0.0011	0.0009	0.0003	0.0000
15 years (2016-2030)	0.0867	0.0594	0.0759	0.0534	0.0043	0.0029	130.2		0.0092	0.0012	0.0009	0.0006	0.0000	0.0008	0.0006	0.0002	0.0000
30 years (2016-2045)	0.1096	0.0768	0.1204	0.0786	0.0028	0.0020	137.1		0.0085	0.0007	0.0005	0.0003	0.0000	0.0004	0.0004	0.0001	0.0000

NOTES: General — All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results :

MA-NEMA
NEMA (Northeast Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1394	0.0821	0.0718	0.0478														0.0478	0.0478	0.0509	0.0509
2016	0.1317	0.0757	0.0857	0.0539	127.7	*0.0*	63.8	0.0348	0.0191	0.0514	0.0304							0.0473	0.0473	0.0504	0.0504
2017	0.1273	0.0734	0.0969	0.0567	185.4	*0.0*	92.7	0.0336	0.0184	0.0589	0.0323		0.0336	0.0184	0.0589	0.0323		0.0469	0.0469	0.0500	0.0500
2018	0.0871	0.0642	0.0735	0.0581	143.6	*0.0*	71.8	0.0223	0.0159	0.0435	0.0333		0.0223	0.0159	0.0435	0.0333		0.0466	0.0466	0.0497	0.0497
2019	0.0850	0.0640	0.0699	0.0584	133.2	*0.0*	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0887	0.0622	0.0769	0.0568	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0892	0.0669	0.0794	0.0627	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0963	0.0701	0.0857	0.0651	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0980	0.0716	0.1003	0.0671	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.1026	0.0743	0.0884	0.0707	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1120	0.0786	0.0997	0.0753	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1105	0.0801	0.1128	0.0775	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1037	0.0822	0.0945	0.0789	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1055	0.0850	0.1067	0.0834	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1142	0.0887	0.1105	0.0869	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1293	0.0955	0.1527	0.0995	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1335	0.0985	0.1592	0.1036	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1380	0.1016	0.1661	0.1079	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1425	0.1049	0.1733	0.1124	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1473	0.1083	0.1808	0.1171	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1522	0.1118	0.1887	0.1220	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1572	0.1154	0.1969	0.1271	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1625	0.1191	0.2055	0.1325	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1680	0.1230	0.2145	0.1381	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1736	0.1271	0.2239	0.1440	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1795	0.1312	0.2338	0.1501	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1856	0.1356	0.2441	0.1565	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1918	0.1400	0.2549	0.1633	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1984	0.1447	0.2662	0.1703	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.2051	0.1495	0.2781	0.1777	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2121	0.1545	0.2904	0.1854	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.1021	0.0700	0.0854	0.0621	149.2	111.9	130.5	0.0099	0.0058	0.0167	0.0104	0.0000	0.0062	0.0038	0.0113	0.0072	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1052	0.0747	0.0941	0.0688	152.2	140.1	146.1	0.0070	0.0041	0.0118	0.0074	0.0000	0.0043	0.0027	0.0080	0.0051	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1307	0.0944	0.1435	0.0972	154.9	167.6	161.2	0.0041	0.0024	0.0070	0.0043	0.0000	0.0026	0.0016	0.0047	0.0030	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Page Two of Two

Zone: MA-NEMA

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1212	0.0686	0.0592	0.0372			39.7	17.0%	0.0067								
2016	0.1136	0.0622	0.0714	0.0422	0.0425	0.0268	118.2	17.0%	0.0072	0.0171	0.0438	0.0260	0.0000				
2017	0.1096	0.0601	0.0817	0.0449	0.0250	0.0159	171.7	17.0%	0.0072	0.0165	0.0502	0.0276	0.0000	0.0165	0.0502	0.0276	0.0000
2018	0.0728	0.0518	0.0604	0.0462	0.0116	0.0076	132.9	17.0%	0.0071	0.0142	0.0371	0.0284	0.0000	0.0142	0.0371		
2019	0.0710	0.0518	0.0571	0.0466	0.0075	0.0050	123.3	17.0%	0.0070								
2020	0.0745	0.0502	0.0637	0.0453	0.0073	0.0050	135.8	17.0%	0.0069								
2021	0.0731	0.0526	0.0641	0.0488	0.0013	0.0012	138.6	17.0%	0.0088								
2022	0.0793	0.0553	0.0697	0.0507	0.0013	0.0012	139.9	17.0%	0.0090								
2023	0.0807	0.0564	0.0827	0.0523	0.0013	0.0012	137.7	17.0%	0.0093								
2024	0.0844	0.0584	0.0714	0.0552	0.0013	0.0012	140.6	17.0%	0.0097								
2025	0.0929	0.0622	0.0816	0.0592	0.0013	0.0012	143.5	17.0%	0.0099								
2026	0.0916	0.0637	0.0937	0.0613	0.0013	0.0012	144.1	17.0%	0.0098								
2027	0.0854	0.0657	0.0769	0.0626	0.0013	0.0012	142.7	17.0%	0.0098								
2028	0.0859	0.0671	0.0870	0.0656	0.0013	0.0012	146.2	17.0%	0.0109								
2029	0.0940	0.0706	0.0906	0.0689	0.0013	0.0012	151.9	17.0%	0.0108								
2030	0.1079	0.0769	0.1294	0.0806	0.0013	0.0012	153.5	17.0%	0.0107								
2031	0.1118	0.0797	0.1354	0.0844	0.0013	0.0012	147.0	17.0%	0.0107								
2032	0.1159	0.0825	0.1417	0.0883	0.0013	0.0012	147.0	17.0%	0.0107								
2033	0.1200	0.0855	0.1483	0.0924	0.0013	0.0012	147.0	17.0%	0.0107								
2034	0.1244	0.0886	0.1552	0.0967	0.0013	0.0012	147.0	17.0%	0.0107								
2035	0.1289	0.0918	0.1624	0.1012	0.0013	0.0012	147.0	17.0%	0.0107								
2036	0.1335	0.0951	0.1699	0.1059	0.0013	0.0012	147.0	17.0%	0.0107								
2037	0.1384	0.0986	0.1778	0.1108	0.0013	0.0012	147.0	17.0%	0.0107								
2038	0.1434	0.1021	0.1861	0.1160	0.0013	0.0012	147.0	17.0%	0.0107								
2039	0.1486	0.1058	0.1947	0.1213	0.0013	0.0012	147.0	17.0%	0.0107								
2040	0.1539	0.1097	0.2038	0.1270	0.0013	0.0012	147.0	17.0%	0.0107								
2041	0.1595	0.1136	0.2132	0.1329	0.0013	0.0012	147.0	17.0%	0.0107								
2042	0.1653	0.1177	0.2231	0.1391	0.0013	0.0012	147.0	17.0%	0.0107								
2043	0.1712	0.1220	0.2335	0.1455	0.0013	0.0012	147.0	17.0%	0.0107								
2044	0.1774	0.1264	0.2444	0.1523	0.0013	0.0012	147.0	17.0%	0.0108								
2045	0.1838	0.1310	0.2557	0.1594	0.0013	0.0012	147.0	17.0%	0.0108								
Levelized Costs																	
10 years (2016-2025)	0.0856	0.0561	0.0702	0.0488	0.0108	0.0071	138.1		0.0081	0.0052	0.0143	0.0089	0.0000	0.0034	0.0096	0.0031	0.0000
15 years (2016-2030)	0.0877	0.0598	0.0775	0.0543	0.0080	0.0054	140.9		0.0088	0.0037	0.0101	0.0063	0.0000	0.0024	0.0068	0.0022	0.0000
30 years (2016-2045)	0.1103	0.0770	0.1220	0.0796	0.0053	0.0037	143.4		0.0096	0.0022	0.0059	0.0037	0.0000	0.0014	0.0040	0.0013	0.0000

NOTES: General All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results : MA-SEMA SEMA (Southeast Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1393	0.0815	0.0689	0.0456														0.0478	0.0478	0.0509	0.0509
2016	0.1302	0.0748	0.0825	0.0515	41.2	*0.0*	20.6	0.0344	0.0188	0.0493	0.0289							0.0473	0.0473	0.0504	0.0504
2017	0.1251	0.0726	0.0943	0.0550	123.7	*0.0*	61.8	0.0330	0.0182	0.0572	0.0312		0.0330	0.0182	0.0572	0.0312		0.0469	0.0469	0.0500	0.0500
2018	0.0854	0.0635	0.0712	0.0566	200.9	*0.0*	100.4	0.0219	0.0157	0.0420	0.0323		0.0219	0.0157	0.0420	0.0323		0.0466	0.0466	0.0497	0.0497
2019	0.0834	0.0634	0.0677	0.0570	174.1	*0.0*	87.0											0.0462	0.0462	0.0492	0.0492
2020	0.0873	0.0615	0.0748	0.0555	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0878	0.0662	0.0770	0.0611	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0951	0.0694	0.0835	0.0637	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0968	0.0713	0.0984	0.0660	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.1016	0.0740	0.0863	0.0695	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1107	0.0779	0.0976	0.0740	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1094	0.0796	0.1107	0.0764	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1026	0.0819	0.0924	0.0777	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1043	0.0848	0.1049	0.0822	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1133	0.0884	0.1086	0.0856	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1286	0.0952	0.1498	0.0977	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1329	0.0982	0.1564	0.1018	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1373	0.1014	0.1633	0.1061	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1419	0.1047	0.1704	0.1105	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1467	0.1081	0.1780	0.1152	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1516	0.1116	0.1859	0.1201	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1567	0.1153	0.1941	0.1253	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1620	0.1190	0.2028	0.1307	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1675	0.1230	0.2118	0.1363	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1732	0.1270	0.2213	0.1422	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1791	0.1312	0.2312	0.1484	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1852	0.1356	0.2417	0.1549	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1915	0.1401	0.2526	0.1617	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1981	0.1448	0.2640	0.1688	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.2049	0.1497	0.2759	0.1763	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2120	0.1547	0.2885	0.1841	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.1007	0.0694	0.0830	0.0605	143.2	111.9	127.5	0.0097	0.0057	0.0161	0.0100	0.0000	0.0060	0.0037	0.0109	0.0070	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1038	0.0742	0.0918	0.0674	147.9	140.1	144.0	0.0069	0.0040	0.0114	0.0071	0.0000	0.0043	0.0026	0.0077	0.0049	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1297	0.0940	0.1411	0.0957	152.4	167.6	160.0	0.0040	0.0024	0.0067	0.0042	0.0000	0.0025	0.0016	0.0045	0.0029	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: MA-SEMA

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1211	0.0681	0.0565	0.0352			39.7	17.0%	0.0067								
2016	0.1122	0.0614	0.0684	0.0400	0.0425	0.0268	38.2	17.0%	0.0072	0.0169	0.0421	0.0246	0.0000				
2017	0.1076	0.0594	0.0793	0.0433	0.0250	0.0159	114.5	17.0%	0.0072	0.0163	0.0487	0.0266	0.0000	0.0163	0.0487	0.0266	0.0000
2018	0.0713	0.0512	0.0582	0.0449	0.0116	0.0076	186.0	17.0%	0.0071	0.0140	0.0358	0.0276	0.0000	0.0140	0.0358		
2019	0.0695	0.0512	0.0551	0.0453	0.0075	0.0050	161.2	17.0%	0.0070								
2020	0.0733	0.0496	0.0617	0.0441	0.0073	0.0050	135.8	17.0%	0.0069								
2021	0.0718	0.0520	0.0619	0.0473	0.0013	0.0012	138.6	17.0%	0.0088								
2022	0.0783	0.0547	0.0676	0.0494	0.0013	0.0012	139.9	17.0%	0.0090								
2023	0.0796	0.0561	0.0810	0.0512	0.0013	0.0012	137.7	17.0%	0.0093								
2024	0.0835	0.0581	0.0695	0.0540	0.0013	0.0012	140.6	17.0%	0.0097								
2025	0.0917	0.0616	0.0797	0.0580	0.0013	0.0012	143.5	17.0%	0.0099								
2026	0.0906	0.0632	0.0918	0.0603	0.0013	0.0012	144.1	17.0%	0.0098								
2027	0.0844	0.0654	0.0750	0.0615	0.0013	0.0012	142.7	17.0%	0.0098								
2028	0.0848	0.0669	0.0853	0.0645	0.0013	0.0012	146.2	17.0%	0.0109								
2029	0.0932	0.0703	0.0889	0.0677	0.0013	0.0012	151.9	17.0%	0.0108								
2030	0.1073	0.0766	0.1268	0.0789	0.0013	0.0012	153.5	17.0%	0.0107								
2031	0.1112	0.0794	0.1328	0.0827	0.0013	0.0012	147.0	17.0%	0.0107								
2032	0.1153	0.0823	0.1391	0.0866	0.0013	0.0012	147.0	17.0%	0.0107								
2033	0.1195	0.0853	0.1457	0.0907	0.0013	0.0012	147.0	17.0%	0.0107								
2034	0.1238	0.0884	0.1526	0.0950	0.0013	0.0012	147.0	17.0%	0.0107								
2035	0.1284	0.0917	0.1598	0.0995	0.0013	0.0012	147.0	17.0%	0.0107								
2036	0.1330	0.0950	0.1674	0.1042	0.0013	0.0012	147.0	17.0%	0.0107								
2037	0.1379	0.0985	0.1753	0.1092	0.0013	0.0012	147.0	17.0%	0.0107								
2038	0.1429	0.1021	0.1836	0.1143	0.0013	0.0012	147.0	17.0%	0.0107								
2039	0.1481	0.1058	0.1923	0.1198	0.0013	0.0012	147.0	17.0%	0.0107								
2040	0.1536	0.1097	0.2014	0.1254	0.0013	0.0012	147.0	17.0%	0.0107								
2041	0.1592	0.1137	0.2110	0.1314	0.0013	0.0012	147.0	17.0%	0.0107								
2042	0.1650	0.1178	0.2210	0.1376	0.0013	0.0012	147.0	17.0%	0.0107								
2043	0.1710	0.1221	0.2314	0.1441	0.0013	0.0012	147.0	17.0%	0.0107								
2044	0.1772	0.1266	0.2424	0.1509	0.0013	0.0012	147.0	17.0%	0.0108								
2045	0.1837	0.1312	0.2539	0.1581	0.0013	0.0012	147.0	17.0%	0.0108								
Levelized Costs																	
10 years (2016-2025)	0.0843	0.0555	0.0680	0.0474	0.0108	0.0071	132.6		0.0081	0.0051	0.0138	0.0085	0.0000	0.0033	0.0093	0.0030	0.0000
15 years (2016-2030)	0.0865	0.0593	0.0754	0.0530	0.0080	0.0054	137.0		0.0088	0.0036	0.0097	0.0060	0.0000	0.0024	0.0066	0.0021	0.0000
30 years (2016-2045)	0.1094	0.0767	0.1198	0.0782	0.0053	0.0037	141.1		0.0096	0.0021	0.0057	0.0036	0.0000	0.0014	0.0039	0.0012	0.0000

NOTES: General All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results :

MA-WCMA
WCMA (West-Central Massachusetts)

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1393	0.0817	0.0699	0.0464														0.0478	0.0478	0.0509	0.0509
2016	0.1307	0.0752	0.0839	0.0528	41.2	*0.0*	20.6	0.0345	0.0189	0.0503	0.0297							0.0473	0.0473	0.0504	0.0504
2017	0.1259	0.0729	0.0955	0.0559	123.7	*0.0*	61.8	0.0332	0.0183	0.0580	0.0318		0.0332	0.0183	0.0580	0.0318		0.0469	0.0469	0.0500	0.0500
2018	0.0860	0.0638	0.0721	0.0572	143.6	*0.0*	71.8	0.0220	0.0158	0.0426	0.0327		0.0220	0.0158	0.0426	0.0327		0.0466	0.0466	0.0497	0.0497
2019	0.0842	0.0636	0.0685	0.0576	133.2	*0.0*	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0877	0.0618	0.0756	0.0560	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0882	0.0664	0.0780	0.0618	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0954	0.0696	0.0843	0.0642	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0972	0.0714	0.0991	0.0664	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.1019	0.0741	0.0871	0.0699	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1107	0.0781	0.0984	0.0749	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1095	0.0798	0.1116	0.0768	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1030	0.0820	0.0932	0.0782	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1048	0.0849	0.1055	0.0826	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1136	0.0885	0.1093	0.0861	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1288	0.0953	0.1510	0.0984	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1331	0.0983	0.1576	0.1025	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1375	0.1015	0.1645	0.1068	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1421	0.1048	0.1717	0.1113	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1468	0.1082	0.1792	0.1160	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1518	0.1117	0.1871	0.1209	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1569	0.1153	0.1954	0.1261	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1622	0.1191	0.2040	0.1315	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1676	0.1230	0.2131	0.1371	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1733	0.1271	0.2226	0.1430	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1792	0.1313	0.2325	0.1492	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1853	0.1356	0.2429	0.1557	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1916	0.1402	0.2538	0.1625	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1982	0.1448	0.2652	0.1696	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.2050	0.1497	0.2772	0.1770	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2120	0.1547	0.2897	0.1848	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.1011	0.0696	0.0840	0.0612	132.9	111.9	122.4	0.0098	0.0058	0.0164	0.0102	0.0000	0.0061	0.0037	0.0111	0.0071	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1042	0.0744	0.0927	0.0680	140.7	140.1	140.4	0.0069	0.0041	0.0116	0.0072	0.0000	0.0043	0.0026	0.0078	0.0050	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1300	0.0942	0.1421	0.0963	148.1	167.6	157.8	0.0041	0.0024	0.0068	0.0042	0.0000	0.0025	0.0016	0.0046	0.0029	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: MA-WCMA

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1211	0.0683	0.0575	0.0359			39.7	17.0%	0.0067								
2016	0.1126	0.0617	0.0697	0.0412	0.0425	0.0268	38.2	17.0%	0.0072	0.0169	0.0429	0.0253	0.0000				
2017	0.1084	0.0597	0.0804	0.0441	0.0250	0.0159	114.5	17.0%	0.0072	0.0164	0.0494	0.0271	0.0000	0.0164	0.0494	0.0271	0.0000
2018	0.0718	0.0514	0.0591	0.0454	0.0116	0.0076	132.9	17.0%	0.0071	0.0141	0.0363	0.0279	0.0000	0.0141	0.0363		
2019	0.0702	0.0514	0.0559	0.0458	0.0075	0.0050	123.3	17.0%	0.0070								
2020	0.0736	0.0498	0.0625	0.0446	0.0073	0.0050	135.8	17.0%	0.0069								
2021	0.0722	0.0522	0.0628	0.0479	0.0013	0.0012	138.6	17.0%	0.0088								
2022	0.0786	0.0549	0.0684	0.0499	0.0013	0.0012	139.9	17.0%	0.0090								
2023	0.0799	0.0562	0.0816	0.0516	0.0013	0.0012	137.7	17.0%	0.0093								
2024	0.0838	0.0583	0.0702	0.0544	0.0013	0.0012	140.6	17.0%	0.0097								
2025	0.0917	0.0618	0.0804	0.0588	0.0013	0.0012	143.5	17.0%	0.0099								
2026	0.0907	0.0634	0.0925	0.0607	0.0013	0.0012	144.1	17.0%	0.0098								
2027	0.0847	0.0655	0.0757	0.0620	0.0013	0.0012	142.7	17.0%	0.0098								
2028	0.0853	0.0670	0.0859	0.0649	0.0013	0.0012	146.2	17.0%	0.0109								
2029	0.0934	0.0704	0.0895	0.0682	0.0013	0.0012	151.9	17.0%	0.0108								
2030	0.1075	0.0767	0.1278	0.0796	0.0013	0.0012	153.5	17.0%	0.0107								
2031	0.1114	0.0795	0.1339	0.0834	0.0013	0.0012	147.0	17.0%	0.0107								
2032	0.1154	0.0824	0.1402	0.0873	0.0013	0.0012	147.0	17.0%	0.0107								
2033	0.1196	0.0854	0.1468	0.0914	0.0013	0.0012	147.0	17.0%	0.0107								
2034	0.1240	0.0885	0.1537	0.0957	0.0013	0.0012	147.0	17.0%	0.0107								
2035	0.1285	0.0918	0.1609	0.1002	0.0013	0.0012	147.0	17.0%	0.0107								
2036	0.1332	0.0951	0.1685	0.1049	0.0013	0.0012	147.0	17.0%	0.0107								
2037	0.1380	0.0986	0.1764	0.1099	0.0013	0.0012	147.0	17.0%	0.0107								
2038	0.1431	0.1021	0.1848	0.1151	0.0013	0.0012	147.0	17.0%	0.0107								
2039	0.1483	0.1059	0.1935	0.1205	0.0013	0.0012	147.0	17.0%	0.0107								
2040	0.1537	0.1097	0.2026	0.1261	0.0013	0.0012	147.0	17.0%	0.0107								
2041	0.1593	0.1137	0.2121	0.1321	0.0013	0.0012	147.0	17.0%	0.0107								
2042	0.1651	0.1178	0.2221	0.1383	0.0013	0.0012	147.0	17.0%	0.0107								
2043	0.1711	0.1221	0.2326	0.1448	0.0013	0.0012	147.0	17.0%	0.0107								
2044	0.1773	0.1266	0.2435	0.1517	0.0013	0.0012	147.0	17.0%	0.0108								
2045	0.1837	0.1312	0.2550	0.1588	0.0013	0.0012	147.0	17.0%	0.0108								
Levelized Costs																	
10 years (2016-2025)	0.0847	0.0557	0.0689	0.0480	0.0108	0.0071	123.0		0.0081	0.0052	0.0140	0.0087	0.0000	0.0034	0.0094	0.0030	0.0000
15 years (2016-2030)	0.0869	0.0595	0.0763	0.0536	0.0080	0.0054	130.2		0.0088	0.0036	0.0099	0.0061	0.0000	0.0024	0.0067	0.0021	0.0000
30 years (2016-2045)	0.1097	0.0768	0.1208	0.0788	0.0053	0.0037	137.1		0.0096	0.0021	0.0058	0.0036	0.0000	0.0014	0.0039	0.0013	0.0000

NOTES: General All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results : MA Massachusetts

State MA

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1393	0.0818	0.0702	0.0466														0.0478	0.0478	0.0509	0.0509
2016	0.1308	0.0752	0.0840	0.0527	79.0	*0.0*	39.5	0.0346	0.0189	0.0504	0.0297							0.0473	0.0473	0.0504	0.0504
2017	0.1261	0.0730	0.0956	0.0559	150.7	*0.0*	75.4	0.0333	0.0183	0.0580	0.0318		0.0333	0.0183	0.0580	0.0318		0.0469	0.0469	0.0500	0.0500
2018	0.0862	0.0638	0.0723	0.0573	159.5	*0.0*	79.8	0.0221	0.0158	0.0427	0.0328		0.0221	0.0158	0.0427	0.0328		0.0466	0.0466	0.0497	0.0497
2019	0.0842	0.0637	0.0687	0.0577	144.6	*0.0*	72.3											0.0462	0.0462	0.0492	0.0492
2020	0.0879	0.0618	0.0758	0.0561	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0884	0.0665	0.0781	0.0619	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0956	0.0697	0.0845	0.0643	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0974	0.0714	0.0993	0.0665	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.1020	0.0741	0.0873	0.0700	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1111	0.0782	0.0986	0.0747	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1098	0.0798	0.1117	0.0769	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1031	0.0821	0.0934	0.0783	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1049	0.0849	0.1057	0.0827	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1137	0.0885	0.1095	0.0862	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1289	0.0953	0.1512	0.0986	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1332	0.0984	0.1577	0.1027	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1376	0.1015	0.1646	0.1069	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1422	0.1048	0.1718	0.1114	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1469	0.1082	0.1793	0.1161	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1518	0.1117	0.1872	0.1210	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1569	0.1153	0.1955	0.1262	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1622	0.1191	0.2041	0.1315	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1677	0.1230	0.2131	0.1372	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1734	0.1271	0.2226	0.1431	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1793	0.1313	0.2325	0.1492	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1853	0.1356	0.2429	0.1557	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1917	0.1401	0.2538	0.1625	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1982	0.1448	0.2651	0.1696	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.2050	0.1496	0.2770	0.1770	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2120	0.1546	0.2895	0.1848	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.1013	0.0696	0.0841	0.0613	142.9	111.9	127.4	0.0098	0.0058	0.0164	0.0102	0.0000	0.0061	0.0038	0.0111	0.0071	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1044	0.0744	0.0929	0.0680	147.7	140.1	143.9	0.0069	0.0041	0.0116	0.0072	0.0000	0.0043	0.0026	0.0078	0.0050	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1302	0.0942	0.1422	0.0964	152.2	167.6	159.9	0.0041	0.0024	0.0068	0.0042	0.0000	0.0025	0.0016	0.0046	0.0029	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: MA

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1211	0.0683	0.0577	0.0361			39.7	17.0%	0.0067								
2016	0.1128	0.0618	0.0698	0.0411	0.0425	0.0268	73.1	17.0%	0.0072	0.0169	0.0429	0.0253	0.0000				
2017	0.1085	0.0598	0.0805	0.0441	0.0250	0.0159	139.6	17.0%	0.0072	0.0164	0.0495	0.0271	0.0000	0.0164	0.0495	0.0271	0.0000
2018	0.0720	0.0515	0.0592	0.0455	0.0116	0.0076	147.7	17.0%	0.0071	0.0141	0.0364	0.0280	0.0000	0.0141	0.0364		
2019	0.0703	0.0514	0.0560	0.0459	0.0075	0.0050	133.9	17.0%	0.0070								
2020	0.0738	0.0499	0.0627	0.0446	0.0073	0.0050	135.8	17.0%	0.0069								
2021	0.0723	0.0523	0.0629	0.0480	0.0013	0.0012	138.6	17.0%	0.0088								
2022	0.0787	0.0550	0.0686	0.0500	0.0013	0.0012	139.9	17.0%	0.0090								
2023	0.0800	0.0562	0.0818	0.0517	0.0013	0.0012	137.7	17.0%	0.0093								
2024	0.0839	0.0583	0.0704	0.0546	0.0013	0.0012	140.6	17.0%	0.0097								
2025	0.0921	0.0619	0.0806	0.0587	0.0013	0.0012	143.5	17.0%	0.0099								
2026	0.0909	0.0634	0.0927	0.0608	0.0013	0.0012	144.1	17.0%	0.0098								
2027	0.0848	0.0655	0.0759	0.0620	0.0013	0.0012	142.7	17.0%	0.0098								
2028	0.0853	0.0670	0.0861	0.0650	0.0013	0.0012	146.2	17.0%	0.0109								
2029	0.0935	0.0704	0.0897	0.0683	0.0013	0.0012	151.9	17.0%	0.0108								
2030	0.1076	0.0767	0.1280	0.0797	0.0013	0.0012	153.5	17.0%	0.0107								
2031	0.1115	0.0795	0.1340	0.0835	0.0013	0.0012	147.0	17.0%	0.0107								
2032	0.1155	0.0824	0.1403	0.0874	0.0013	0.0012	147.0	17.0%	0.0107								
2033	0.1197	0.0854	0.1469	0.0915	0.0013	0.0012	147.0	17.0%	0.0107								
2034	0.1241	0.0885	0.1538	0.0958	0.0013	0.0012	147.0	17.0%	0.0107								
2035	0.1286	0.0917	0.1610	0.1003	0.0013	0.0012	147.0	17.0%	0.0107								
2036	0.1333	0.0951	0.1686	0.1050	0.0013	0.0012	147.0	17.0%	0.0107								
2037	0.1381	0.0985	0.1765	0.1100	0.0013	0.0012	147.0	17.0%	0.0107								
2038	0.1431	0.1021	0.1848	0.1151	0.0013	0.0012	147.0	17.0%	0.0107								
2039	0.1483	0.1058	0.1935	0.1205	0.0013	0.0012	147.0	17.0%	0.0107								
2040	0.1537	0.1097	0.2026	0.1262	0.0013	0.0012	147.0	17.0%	0.0107								
2041	0.1593	0.1137	0.2121	0.1321	0.0013	0.0012	147.0	17.0%	0.0107								
2042	0.1651	0.1178	0.2221	0.1383	0.0013	0.0012	147.0	17.0%	0.0107								
2043	0.1711	0.1221	0.2325	0.1448	0.0013	0.0012	147.0	17.0%	0.0107								
2044	0.1773	0.1265	0.2434	0.1516	0.0013	0.0012	147.0	17.0%	0.0108								
2045	0.1838	0.1311	0.2549	0.1587	0.0013	0.0012	147.0	17.0%	0.0108								
Levelized Costs																	
10 years (2016-2025)	0.0848	0.0558	0.0690	0.0481	0.0108	0.0071	132.3		0.0081	0.0052	0.0140	0.0087	0.0000	0.0034	0.0094	0.0030	0.0000
15 years (2016-2030)	0.0870	0.0595	0.0764	0.0536	0.0080	0.0054	136.8		0.0088	0.0036	0.0099	0.0061	0.0000	0.0024	0.0067	0.0021	0.0000
30 years (2016-2045)	0.1098	0.0768	0.1209	0.0789	0.0053	0.0037	141.0		0.0096	0.0021	0.0058	0.0036	0.0000	0.0014	0.0039	0.0013	0.0000

NOTES: General — All Avoided Costs are in Year 2015 Dollars

periods:

Table One: Avoided Cost of Electricity (2015 $) Results : ME Maine

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State ME

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1317	0.0748	0.0621	0.0389														0.0478	0.0478	0.0509	0.0509
2016	0.1206	0.0675	0.0753	0.0443	41.2	0.0	20.6	0.0061	0.0034	-0.0033	-0.0020							0.0473	0.0473	0.0504	0.0504
2017	0.1167	0.0653	0.0870	0.0478	123.7	0.0	61.8	0.0059	0.0033	-0.0039	-0.0021		0.0059	0.0033	-0.0039	-0.0021		0.0469	0.0469	0.0500	0.0500
2018	0.0782	0.0565	0.0643	0.0497	143.6	0.0	71.8	0.0040	0.0029	-0.0028	-0.0022		0.0040	0.0029	-0.0028	-0.0022		0.0466	0.0466	0.0497	0.0497
2019	0.0756	0.0566	0.0609	0.0503	133.2	0.0	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0784	0.0549	0.0683	0.0490	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0760	0.0570	0.0678	0.0522	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0838	0.0595	0.0738	0.0540	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0851	0.0608	0.0882	0.0557	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.0872	0.0628	0.0755	0.0585	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.0907	0.0655	0.0851	0.0625	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.0952	0.0678	0.1000	0.0654	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.0904	0.0701	0.0812	0.0665	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.0906	0.0717	0.0919	0.0692	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.0962	0.0750	0.0951	0.0724	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1114	0.0817	0.1380	0.0852	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1152	0.0845	0.1442	0.0890	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1192	0.0874	0.1506	0.0930	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1233	0.0904	0.1574	0.0971	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1275	0.0935	0.1644	0.1015	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1319	0.0967	0.1718	0.1060	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1364	0.1000	0.1795	0.1108	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1410	0.1034	0.1875	0.1157	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1459	0.1069	0.1959	0.1209	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1509	0.1106	0.2047	0.1263	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1560	0.1144	0.2139	0.1320	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1614	0.1183	0.2234	0.1379	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1669	0.1223	0.2334	0.1440	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1726	0.1265	0.2439	0.1505	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.1785	0.1308	0.2548	0.1572	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.1847	0.1353	0.2663	0.1643	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.0898	0.0607	0.0744	0.0521	132.9	111.9	122.4	0.0017	0.0010	-0.0011	-0.0007	0.0000	0.0011	0.0007	-0.0007	-0.0005	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.0918	0.0643	0.0822	0.0578	140.7	140.1	140.4	0.0012	0.0007	-0.0008	-0.0005	0.0000	0.0008	0.0005	-0.0005	-0.0003	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1137	0.0816	0.1288	0.0836	148.1	167.6	157.8	0.0007	0.0004	-0.0005	-0.0003	0.0000	0.0005	0.0003	-0.0003	-0.0002	0.0000	0.039	0.039	0.041	0.041

NOTES:

General — All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

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Zone: ME

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures				DRIPE: 2017 vintage measures			
	Energy				Electric Cross DRIPE (5)		Capacity			Rest-of-Pool Energy				Rest-of-Pool Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1203	0.0681	0.0565	0.0352			39.7	17.0%	0.0005								
2016	0.1100	0.0613	0.0685	0.0400	0.0080	0.0051	38.2	17.0%	0.0006	0.0036	-0.0040	-0.0023	0.0000				
2017	0.1065	0.0593	0.0793	0.0433	0.0047	0.0030	114.5	17.0%	0.0006	0.0035	-0.0046	-0.0025	0.0000	0.0035	-0.0046	-0.0025	0.0000
2018	0.0710	0.0511	0.0582	0.0449	0.0022	0.0014	132.9	17.0%	0.0007	0.0030	-0.0034	-0.0026	0.0000	0.0030	-0.0034		
2019	0.0684	0.0510	0.0550	0.0453	0.0014	0.0009	123.3	17.0%	0.0009								
2020	0.0710	0.0494	0.0617	0.0440	0.0014	0.0009	135.8	17.0%	0.0010								
2021	0.0690	0.0516	0.0615	0.0472	0.0002	0.0002	138.6	17.0%	0.0007								
2022	0.0765	0.0542	0.0674	0.0492	0.0002	0.0002	139.9	17.0%	0.0004								
2023	0.0777	0.0554	0.0806	0.0508	0.0002	0.0002	137.7	17.0%	0.0003								
2024	0.0797	0.0573	0.0690	0.0534	0.0002	0.0002	140.6	17.0%	0.0003								
2025	0.0829	0.0598	0.0778	0.0570	0.0002	0.0002	143.5	17.0%	0.0003								
2026	0.0870	0.0619	0.0914	0.0597	0.0002	0.0002	144.1	17.0%	0.0003								
2027	0.0826	0.0640	0.0741	0.0607	0.0002	0.0002	142.7	17.0%	0.0003								
2028	0.0828	0.0655	0.0840	0.0632	0.0002	0.0002	146.2	17.0%	0.0003								
2029	0.0880	0.0685	0.0870	0.0661	0.0002	0.0002	151.9	17.0%	0.0003								
2030	0.1019	0.0746	0.1263	0.0779	0.0002	0.0002	153.5	17.0%	0.0003								
2031	0.1054	0.0772	0.1320	0.0813	0.0002	0.0002	147.0	17.0%	0.0003								
2032	0.1090	0.0798	0.1379	0.0850	0.0002	0.0002	147.0	17.0%	0.0003								
2033	0.1128	0.0826	0.1441	0.0888	0.0002	0.0002	147.0	17.0%	0.0003								
2034	0.1166	0.0854	0.1505	0.0928	0.0002	0.0002	147.0	17.0%	0.0003								
2035	0.1207	0.0884	0.1573	0.0970	0.0002	0.0002	147.0	17.0%	0.0003								
2036	0.1248	0.0914	0.1643	0.1013	0.0002	0.0002	147.0	17.0%	0.0003								
2037	0.1291	0.0945	0.1717	0.1059	0.0002	0.0002	147.0	17.0%	0.0003								
2038	0.1335	0.0978	0.1794	0.1106	0.0002	0.0002	147.0	17.0%	0.0003								
2039	0.1381	0.1011	0.1875	0.1156	0.0002	0.0002	147.0	17.0%	0.0003								
2040	0.1428	0.1046	0.1959	0.1207	0.0002	0.0002	147.0	17.0%	0.0003								
2041	0.1477	0.1082	0.2047	0.1262	0.0002	0.0002	147.0	17.0%	0.0003								
2042	0.1528	0.1119	0.2139	0.1318	0.0002	0.0002	147.0	17.0%	0.0003								
2043	0.1581	0.1158	0.2235	0.1377	0.0002	0.0002	147.0	17.0%	0.0003								
2044	0.1635	0.1197	0.2335	0.1439	0.0002	0.0002	147.0	17.0%	0.0003								
2045	0.1691	0.1238	0.2440	0.1504	0.0002	0.0002	147.0	17.0%	0.0003								
Levelized Costs																	
10 years (2016-2025)	0.0818	0.0551	0.0677	0.0472	0.0020	0.0013	123.0		0.0006	0.0011	-0.0013	-0.0008	0.0000	0.0007	-0.0009	-0.0003	0.0000
15 years (2016-2030)	0.0837	0.0585	0.0749	0.0525	0.0015	0.0010	130.2		0.0005	0.0008	-0.0009	-0.0006	0.0000	0.0005	-0.0006	-0.0002	0.0000
30 years (2016-2045)	0.1039	0.0745	0.1177	0.0763	0.0010	0.0007	137.1		0.0004	0.0005	-0.0005	-0.0003	0.0000	0.0003	-0.0004	-0.0001	0.0000

NOTES: General All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results : NH New Hampshire

State NH

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1393	0.0824	0.0701	0.0467														0.0478	0.0478	0.0509	0.0509
2016	0.1292	0.0751	0.0833	0.0522	41.2	*0.0*	20.6	0.0055	0.0031	0.0168	0.0098							0.0473	0.0473	0.0504	0.0504
2017	0.1250	0.0732	0.0952	0.0559	123.7	*0.0*	61.8	0.0053	0.0030	0.0194	0.0106		0.0053	0.0030	0.0194	0.0106		0.0469	0.0469	0.0500	0.0500
2018	0.0854	0.0635	0.0715	0.0568	143.6	*0.0*	71.8	0.0036	0.0026	0.0142	0.0110		0.0036	0.0026	0.0142	0.0110		0.0466	0.0466	0.0497	0.0497
2019	0.0828	0.0636	0.0682	0.0574	133.2	*0.0*	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0858	0.0620	0.0756	0.0562	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0855	0.0660	0.0770	0.0612	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0938	0.0692	0.0835	0.0637	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0953	0.0709	0.0981	0.0657	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.0979	0.0731	0.0856	0.0687	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1027	0.0763	0.0959	0.0732	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1060	0.0782	0.1097	0.0753	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.1007	0.0803	0.0907	0.0762	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.1008	0.0816	0.1012	0.0789	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1076	0.0856	0.1052	0.0827	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1224	0.0922	0.1474	0.0951	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1266	0.0953	0.1539	0.0991	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1310	0.0985	0.1607	0.1033	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1355	0.1018	0.1678	0.1078	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1402	0.1052	0.1752	0.1124	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1450	0.1088	0.1830	0.1173	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1501	0.1125	0.1912	0.1224	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1553	0.1164	0.1997	0.1277	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1607	0.1203	0.2086	0.1332	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1663	0.1245	0.2180	0.1391	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1722	0.1287	0.2278	0.1452	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1782	0.1332	0.2380	0.1516	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1845	0.1378	0.2487	0.1582	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1909	0.1425	0.2599	0.1652	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.1977	0.1475	0.2717	0.1726	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2046	0.1526	0.2840	0.1802	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.0988	0.0692	0.0831	0.0607	132.9	111.9	122.4	0.0016	0.0009	0.0055	0.0034	0.0000	0.0010	0.0006	0.0037	0.0024	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1013	0.0734	0.0912	0.0668	140.7	140.1	140.4	0.0011	0.0007	0.0039	0.0024	0.0000	0.0007	0.0004	0.0026	0.0017	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1255	0.0925	0.1393	0.0940	148.1	167.6	157.8	0.0007	0.0004	0.0023	0.0014	0.0000	0.0004	0.0003	0.0015	0.0010	0.0000	0.039	0.039	0.041	0.041

NOTES:

General — All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

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Zone: NH

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures				DRIPE: 2017 vintage measures			
										Rest-of-Pool				Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1204	0.0682	0.0569	0.0354			39.7	17.0%	0.0074								
2016	0.1110	0.0614	0.0689	0.0404	0.0085	0.0054	38.2	17.0%	0.0075	0.0033	0.0065	0.0038	0.0000				
2017	0.1069	0.0595	0.0797	0.0435	0.0050	0.0032	114.5	17.0%	0.0077	0.0032	0.0075	0.0041	0.0000	0.0032	0.0075	0.0041	0.0000
2018	0.0713	0.0512	0.0585	0.0450	0.0023	0.0015	132.9	17.0%	0.0071	0.0028	0.0055	0.0042	0.0000	0.0028	0.0055		
2019	0.0688	0.0511	0.0553	0.0455	0.0015	0.0010	123.3	17.0%	0.0072								
2020	0.0714	0.0496	0.0620	0.0442	0.0014	0.0010	135.8	17.0%	0.0073								
2021	0.0698	0.0519	0.0620	0.0475	0.0002	0.0002	138.6	17.0%	0.0087								
2022	0.0773	0.0547	0.0678	0.0496	0.0002	0.0002	139.9	17.0%	0.0088								
2023	0.0786	0.0561	0.0811	0.0513	0.0002	0.0002	137.7	17.0%	0.0089								
2024	0.0808	0.0581	0.0695	0.0541	0.0002	0.0002	140.6	17.0%	0.0090								
2025	0.0852	0.0609	0.0790	0.0581	0.0002	0.0002	143.5	17.0%	0.0090								
2026	0.0886	0.0631	0.0921	0.0605	0.0002	0.0002	144.1	17.0%	0.0086								
2027	0.0842	0.0655	0.0750	0.0617	0.0002	0.0002	142.7	17.0%	0.0082								
2028	0.0847	0.0671	0.0850	0.0645	0.0002	0.0002	146.2	17.0%	0.0078								
2029	0.0905	0.0703	0.0883	0.0677	0.0002	0.0002	151.9	17.0%	0.0082								
2030	0.1044	0.0767	0.1273	0.0793	0.0002	0.0002	153.5	17.0%	0.0079								
2031	0.1083	0.0795	0.1333	0.0830	0.0002	0.0002	147.0	17.0%	0.0079								
2032	0.1123	0.0825	0.1395	0.0869	0.0002	0.0002	147.0	17.0%	0.0079								
2033	0.1164	0.0855	0.1460	0.0910	0.0002	0.0002	147.0	17.0%	0.0079								
2034	0.1207	0.0887	0.1528	0.0952	0.0002	0.0002	147.0	17.0%	0.0079								
2035	0.1252	0.0919	0.1600	0.0997	0.0002	0.0002	147.0	17.0%	0.0079								
2036	0.1298	0.0953	0.1675	0.1043	0.0002	0.0002	147.0	17.0%	0.0079								
2037	0.1346	0.0988	0.1753	0.1092	0.0002	0.0002	147.0	17.0%	0.0079								
2038	0.1395	0.1025	0.1835	0.1143	0.0002	0.0002	147.0	17.0%	0.0079								
2039	0.1447	0.1062	0.1920	0.1196	0.0002	0.0002	147.0	17.0%	0.0079								
2040	0.1500	0.1102	0.2010	0.1252	0.0002	0.0002	147.0	17.0%	0.0079								
2041	0.1555	0.1142	0.2104	0.1311	0.0002	0.0002	147.0	17.0%	0.0080								
2042	0.1613	0.1184	0.2202	0.1372	0.0002	0.0002	147.0	17.0%	0.0080								
2043	0.1672	0.1228	0.2305	0.1436	0.0002	0.0002	147.0	17.0%	0.0080								
2044	0.1734	0.1273	0.2413	0.1503	0.0002	0.0002	147.0	17.0%	0.0080								
2045	0.1798	0.1320	0.2525	0.1574	0.0002	0.0002	147.0	17.0%	0.0080								
Levelized Costs																	
10 years (2016-2025)	0.0826	0.0554	0.0682	0.0476	0.0021	0.0014	123.0		0.0081	0.0010	0.0021	0.0013	0.0000	0.0007	0.0014	0.0005	0.0000
15 years (2016-2030)	0.0848	0.0592	0.0755	0.0532	0.0016	0.0011	130.2		0.0081	0.0007	0.0015	0.0009	0.0000	0.0005	0.0010	0.0003	0.0000
30 years (2016-2045)	0.1071	0.0768	0.1198	0.0782	0.0010	0.0007	137.1		0.0080	0.0004	0.0009	0.0005	0.0000	0.0003	0.0006	0.0002	0.0000

NOTES: General — All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results : RI Rhode Island

State RI

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate — Energy				DRIPE: 2016 vintage measures Intrastate — Capacity (See note 2)	DRIPE: 2017 vintage measures Intrastate — Energy				DRIPE: 2017 vintage measures Intrastate — Capacity (See note 2)	Avoided Non-Embedded Costs			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Annual Value	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1361	0.0784	0.0662	0.0429														0.0478	0.0478	0.0509	0.0509
2016	0.1272	0.0717	0.0798	0.0487	41.2	*0.0*	20.6	0.0041	0.0022	0.0170	0.0100							0.0473	0.0473	0.0504	0.0504
2017	0.1230	0.0702	0.0922	0.0528	123.7	*0.0*	61.8	0.0039	0.0022	0.0196	0.0107		0.0039	0.0022	0.0196	0.0107		0.0469	0.0469	0.0500	0.0500
2018	0.0838	0.0617	0.0697	0.0550	143.6	*0.0*	71.8	0.0026	0.0019	0.0144	0.0111		0.0026	0.0019	0.0144	0.0111		0.0466	0.0466	0.0497	0.0497
2019	0.0824	0.0622	0.0668	0.0560	133.2	*0.0*	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0861	0.0601	0.0737	0.0543	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0857	0.0640	0.0752	0.0591	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0924	0.0666	0.0810	0.0610	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0933	0.0676	0.0950	0.0625	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.0973	0.0695	0.0822	0.0652	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.1058	0.0730	0.0930	0.0692	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.1041	0.0742	0.1057	0.0712	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.0970	0.0762	0.0870	0.0722	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.0971	0.0774	0.0978	0.0750	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.1065	0.0815	0.1021	0.0789	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1216	0.0881	0.1432	0.0909	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1258	0.0911	0.1498	0.0950	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1303	0.0943	0.1567	0.0993	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1348	0.0975	0.1639	0.1037	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1396	0.1009	0.1714	0.1084	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1445	0.1045	0.1793	0.1133	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1496	0.1081	0.1876	0.1185	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1549	0.1119	0.1962	0.1239	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1604	0.1158	0.2053	0.1295	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1661	0.1199	0.2148	0.1354	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1720	0.1241	0.2247	0.1416	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1781	0.1284	0.2351	0.1481	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1844	0.1329	0.2460	0.1549	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1910	0.1376	0.2574	0.1620	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.1978	0.1425	0.2694	0.1694	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.2048	0.1475	0.2819	0.1772	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.0981	0.0666	0.0806	0.0580	132.9	111.9	122.4	0.0012	0.0007	0.0055	0.0034	0.0000	0.0007	0.0004	0.0037	0.0024	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.1001	0.0704	0.0883	0.0637	140.7	140.1	140.4	0.0008	0.0005	0.0039	0.0024	0.0000	0.0005	0.0003	0.0026	0.0017	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1246	0.0888	0.1363	0.0907	148.1	167.6	157.8	0.0005	0.0003	0.0023	0.0014	0.0000	0.0003	0.0002	0.0016	0.0010	0.0000	0.039	0.039	0.041	0.041

NOTES:

General — All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: RI

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures				DRIPE: 2017 vintage measures			
										Rest-of-Pool				Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak	Winter four-hour Peak	Winter Other Peak	Summer four-hour Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1211	0.0682	0.0570	0.0355			39.7	17.0%	0.0038								
2016	0.1124	0.0615	0.0690	0.0404	0.0056	0.0036	38.2	17.0%	0.0043	0.0011	0.0093	0.0054	0.0000				
2017	0.1080	0.0595	0.0798	0.0436	0.0033	0.0021	114.5	17.0%	0.0048	0.0011	0.0107	0.0059	0.0000	0.0011	0.0107	0.0059	0.0000
2018	0.0715	0.0513	0.0586	0.0451	0.0015	0.0010	132.9	17.0%	0.0053	0.0009	0.0079	0.0061	0.0000	0.0009	0.0079		
2019	0.0698	0.0512	0.0555	0.0456	0.0010	0.0007	123.3	17.0%	0.0058								
2020	0.0735	0.0497	0.0621	0.0443	0.0010	0.0007	135.8	17.0%	0.0055								
2021	0.0720	0.0521	0.0623	0.0476	0.0002	0.0002	138.6	17.0%	0.0066								
2022	0.0785	0.0548	0.0680	0.0497	0.0002	0.0002	139.9	17.0%	0.0063								
2023	0.0797	0.0562	0.0813	0.0514	0.0002	0.0002	137.7	17.0%	0.0059								
2024	0.0836	0.0582	0.0698	0.0542	0.0002	0.0002	140.6	17.0%	0.0056								
2025	0.0918	0.0617	0.0800	0.0582	0.0002	0.0002	143.5	17.0%	0.0052								
2026	0.0907	0.0633	0.0922	0.0605	0.0002	0.0002	144.1	17.0%	0.0048								
2027	0.0845	0.0654	0.0754	0.0617	0.0002	0.0002	142.7	17.0%	0.0045								
2028	0.0850	0.0670	0.0857	0.0647	0.0002	0.0002	146.2	17.0%	0.0041								
2029	0.0933	0.0704	0.0892	0.0680	0.0002	0.0002	151.9	17.0%	0.0044								
2030	0.1074	0.0767	0.1273	0.0793	0.0002	0.0002	153.5	17.0%	0.0041								
2031	0.1113	0.0795	0.1333	0.0830	0.0002	0.0002	147.0	17.0%	0.0041								
2032	0.1154	0.0824	0.1396	0.0869	0.0002	0.0002	147.0	17.0%	0.0041								
2033	0.1196	0.0854	0.1462	0.0910	0.0002	0.0002	147.0	17.0%	0.0041								
2034	0.1239	0.0885	0.1531	0.0953	0.0002	0.0002	147.0	17.0%	0.0041								
2035	0.1285	0.0917	0.1604	0.0998	0.0002	0.0002	147.0	17.0%	0.0041								
2036	0.1331	0.0950	0.1679	0.1046	0.0002	0.0002	147.0	17.0%	0.0041								
2037	0.1380	0.0985	0.1759	0.1095	0.0002	0.0002	147.0	17.0%	0.0041								
2038	0.1430	0.1021	0.1842	0.1147	0.0002	0.0002	147.0	17.0%	0.0041								
2039	0.1482	0.1058	0.1929	0.1201	0.0002	0.0002	147.0	17.0%	0.0041								
2040	0.1536	0.1097	0.2020	0.1258	0.0002	0.0002	147.0	17.0%	0.0041								
2041	0.1593	0.1137	0.2116	0.1317	0.0002	0.0002	147.0	17.0%	0.0041								
2042	0.1651	0.1178	0.2216	0.1380	0.0002	0.0002	147.0	17.0%	0.0041								
2043	0.1711	0.1221	0.2320	0.1445	0.0002	0.0002	147.0	17.0%	0.0041								
2044	0.1773	0.1266	0.2430	0.1513	0.0002	0.0002	147.0	17.0%	0.0041								
2045	0.1838	0.1312	0.2545	0.1585	0.0002	0.0002	147.0	17.0%	0.0041								
Levelized Costs																	
10 years (2016-2025)	0.0845	0.0556	0.0684	0.0477	0.0014	0.0009	123.0		0.0055	0.0003	0.0030	0.0019	0.0000	0.0002	0.0021	0.0007	0.0000
15 years (2016-2030)	0.0867	0.0594	0.0758	0.0533	0.0011	0.0007	130.2		0.0052	0.0002	0.0021	0.0013	0.0000	0.0002	0.0014	0.0005	0.0000
30 years (2016-2045)	0.1096	0.0768	0.1203	0.0785	0.0007	0.0005	137.1		0.0048	0.0001	0.0013	0.0008	0.0000	0.0001	0.0009	0.0003	0.0000

NOTES: General — All Avoided Costs are in Year 2015 Dollars
periods:

Table One: Avoided Cost of Electricity (2015 $) Results : VT Vermont

State VT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	2.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

0.0716717

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak	Annual Value	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak	Annual Value	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2015	0.1314	0.0744	0.0623	0.0389														0.0478	0.0478	0.0509	0.0509
2016	0.1214	0.0672	0.0758	0.0450	41.2	0.0	20.6	0.0027	0.0015	-0.0019	-0.0011							0.0473	0.0473	0.0504	0.0504
2017	0.1169	0.0651	0.0876	0.0481	123.7	0.0	61.8	0.0026	0.0015	-0.0022	-0.0012		0.0026	0.0015	-0.0022	-0.0012		0.0469	0.0469	0.0500	0.0500
2018	0.0780	0.0559	0.0641	0.0493	143.6	0.0	71.8	0.0018	0.0013	-0.0016	-0.0012		0.0018	0.0013	-0.0016	-0.0012		0.0466	0.0466	0.0497	0.0497
2019	0.0756	0.0559	0.0606	0.0498	133.2	0.0	66.6											0.0462	0.0462	0.0492	0.0492
2020	0.0782	0.0541	0.0679	0.0484	146.6	191.1	168.9											0.0458	0.0458	0.0488	0.0488
2021	0.0766	0.0567	0.0680	0.0520	149.7	195.1	172.4											0.0446	0.0446	0.0475	0.0475
2022	0.0846	0.0597	0.0742	0.0543	151.1	196.9	174.0											0.0433	0.0433	0.0462	0.0462
2023	0.0860	0.0612	0.0887	0.0561	148.7	193.9	171.3											0.0421	0.0421	0.0449	0.0449
2024	0.0886	0.0633	0.0761	0.0592	151.8	197.9	174.8											0.0409	0.0409	0.0436	0.0436
2025	0.0944	0.0666	0.0870	0.0643	155.0	202.0	178.5											0.0397	0.0397	0.0423	0.0423
2026	0.0971	0.0690	0.1006	0.0661	155.6	202.8	179.2											0.0385	0.0385	0.0410	0.0410
2027	0.0919	0.0714	0.0822	0.0674	154.2	200.9	177.5											0.0373	0.0373	0.0397	0.0397
2028	0.0926	0.0731	0.0932	0.0706	157.9	205.8	181.8											0.0361	0.0361	0.0385	0.0385
2029	0.0993	0.0766	0.0970	0.0740	164.0	213.8	188.9											0.0349	0.0349	0.0372	0.0372
2030	0.1142	0.0836	0.1391	0.0867	165.8	216.1	191.0											0.0337	0.0337	0.0359	0.0359
2031	0.1184	0.0867	0.1456	0.0908	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2032	0.1228	0.0899	0.1525	0.0950	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2033	0.1273	0.0932	0.1596	0.0995	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2034	0.1320	0.0966	0.1671	0.1041	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2035	0.1368	0.1002	0.1749	0.1090	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2036	0.1418	0.1039	0.1831	0.1141	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2037	0.1471	0.1077	0.1917	0.1195	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2038	0.1525	0.1117	0.2007	0.1251	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2039	0.1581	0.1158	0.2101	0.1309	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2040	0.1639	0.1200	0.2200	0.1371	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2041	0.1699	0.1244	0.2303	0.1435	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2042	0.1762	0.1290	0.2411	0.1502	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2043	0.1827	0.1338	0.2524	0.1573	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2044	0.1894	0.1387	0.2642	0.1647	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
2045	0.1964	0.1438	0.2766	0.1724	158.7	206.9	182.8											0.0337	0.0337	0.0359	0.0359
Levelized Costs																					
10 years (2016-2025)	0.0905	0.0606	0.0748	0.0523	132.9	111.9	122.4	0.0008	0.0005	-0.0006	-0.0004	0.0000	0.0005	0.0003	-0.0004	-0.0003	0.0000	0.045	0.045	0.047	0.047
15 years (2016-2030)	0.0930	0.0647	0.0828	0.0583	140.7	140.1	140.4	0.0005	0.0003	-0.0004	-0.0003	0.0000	0.0003	0.0002	-0.0003	-0.0002	0.0000	0.042	0.042	0.045	0.045
30 years (2016-2045)	0.1172	0.0838	0.1312	0.0857	148.1	167.6	157.8	0.0003	0.0002	-0.0003	-0.0002	0.0000	0.0002	0.0001	-0.0002	-0.0001	0.0000	0.039	0.039	0.041	0.041

NOTES:

General All Avoided Costs are in Year 2015 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: VT

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak	Winter Super Peak	Winter Other Peak	Summer Super Peak	Summer Other Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2015	0.1205	0.0682	0.0572	0.0357			39.7	17.0%	0.0000								
2016	0.1114	0.0616	0.0695	0.0413	0.0041	0.0026	38.2	17.0%	0.0000	0.0014	-0.0045	-0.0027	0.0000				
2017	0.1073	0.0597	0.0803	0.0441	0.0024	0.0015	114.5	17.0%	0.0000	0.0013	-0.0052	-0.0028	0.0000	0.0013	-0.0052	-0.0028	0.0000
2018	0.0715	0.0513	0.0588	0.0452	0.0011	0.0007	132.9	17.0%	0.0000	0.0011	-0.0038	-0.0029	0.0000	0.0011	-0.0038		
2019	0.0694	0.0513	0.0556	0.0457	0.0007	0.0005	123.3	17.0%	0.0000								
2020	0.0718	0.0496	0.0623	0.0444	0.0007	0.0005	135.8	17.0%	0.0000								
2021	0.0703	0.0520	0.0624	0.0477	0.0001	0.0001	138.6	17.0%	0.0000								
2022	0.0776	0.0548	0.0681	0.0498	0.0001	0.0001	139.9	17.0%	0.0000								
2023	0.0789	0.0561	0.0814	0.0515	0.0001	0.0001	137.7	17.0%	0.0000								
2024	0.0813	0.0581	0.0699	0.0543	0.0001	0.0001	140.6	17.0%	0.0000								
2025	0.0866	0.0611	0.0799	0.0590	0.0001	0.0001	143.5	17.0%	0.0000								
2026	0.0891	0.0633	0.0923	0.0606	0.0001	0.0001	144.1	17.0%	0.0000								
2027	0.0843	0.0655	0.0754	0.0619	0.0001	0.0001	142.7	17.0%	0.0000								
2028	0.0850	0.0671	0.0855	0.0647	0.0001	0.0001	146.2	17.0%	0.0000								
2029	0.0911	0.0703	0.0890	0.0679	0.0001	0.0001	151.9	17.0%	0.0000								
2030	0.1048	0.0767	0.1276	0.0795	0.0001	0.0001	153.5	17.0%	0.0000								
2031	0.1086	0.0795	0.1336	0.0833	0.0001	0.0001	147.0	17.0%	0.0000								
2032	0.1126	0.0825	0.1399	0.0872	0.0001	0.0001	147.0	17.0%	0.0000								
2033	0.1168	0.0855	0.1464	0.0913	0.0001	0.0001	147.0	17.0%	0.0000								
2034	0.1211	0.0887	0.1533	0.0955	0.0001	0.0001	147.0	17.0%	0.0000								
2035	0.1255	0.0919	0.1605	0.1000	0.0001	0.0001	147.0	17.0%	0.0000								
2036	0.1301	0.0953	0.1680	0.1047	0.0001	0.0001	147.0	17.0%	0.0000								
2037	0.1349	0.0988	0.1759	0.1096	0.0001	0.0001	147.0	17.0%	0.0000								
2038	0.1399	0.1024	0.1841	0.1148	0.0001	0.0001	147.0	17.0%	0.0000								
2039	0.1450	0.1062	0.1928	0.1201	0.0001	0.0001	147.0	17.0%	0.0000								
2040	0.1504	0.1101	0.2018	0.1258	0.0001	0.0001	147.0	17.0%	0.0000								
2041	0.1559	0.1142	0.2113	0.1317	0.0001	0.0001	147.0	17.0%	0.0000								
2042	0.1616	0.1184	0.2212	0.1378	0.0001	0.0001	147.0	17.0%	0.0000								
2043	0.1676	0.1227	0.2315	0.1443	0.0001	0.0001	147.0	17.0%	0.0000								
2044	0.1738	0.1272	0.2424	0.1511	0.0001	0.0001	147.0	17.0%	0.0000								
2045	0.1801	0.1319	0.2538	0.1582	0.0001	0.0001	147.0	17.0%	0.0000								
Levelized Costs																	
10 years (2016-2025)	0.0830	0.0556	0.0686	0.0480	0.0010	0.0007	123.0		0.0000	0.0004	-0.0015	-0.0009	0.0000	0.0003	-0.0010	-0.0003	0.0000
15 years (2016-2030)	0.0853	0.0593	0.0760	0.0535	0.0007	0.0005	130.2		0.0000	0.0003	-0.0010	-0.0006	0.0000	0.0002	-0.0007	-0.0002	0.0000
30 years (2016-2045)	0.1075	0.0769	0.1203	0.0786	0.0005	0.0003	137.1		0.0000	0.0002	-0.0006	-0.0004	0.0000	0.0001	-0.0004	-0.0001	0.0000

NOTES: General All Avoided Costs are in Year 2015 Dollars
periods:

Exhibit C-14

Avoided Cost of Gas to Retail Customers by Costing Period - Southern New England (CT, MA, RI), 2015$ per MMBtu

Assumes 2% Distribution System Losses and zero Avoidable Retail Margin

(2015$ per MMBtu)

Costing period	**Shoulder / summer**	**Remaining Winter**	**Peak Days**
Days	**214**	**141**	**10**
Year			
2015	$ 4.45	$ 6.39	$ 10.91
2016	$ 4.66	$ 6.67	$ 8.47
2017	$ 5.36	$ 7.68	$ 9.68
2018	$ 5.84	$ 8.18	$ 10.36
2019	$ 5.89	$ 8.20	$ 10.62
2020	$ 5.53	$ 7.77	$ 10.19
2021	$ 5.83	$ 8.20	$ 10.81
2022	$ 5.91	$ 8.28	$ 10.97
2023	$ 6.00	$ 8.38	$ 11.12
2024	$ 6.19	$ 8.69	$ 11.60
2025	$ 6.31	$ 8.80	$ 11.77
2026	$ 6.41	$ 8.96	$ 12.03
2027	$ 6.49	$ 9.05	$ 12.18
2028	$ 6.60	$ 9.16	$ 12.32
2029	$ 6.80	$ 9.35	$ 12.51
2030	$ 7.08	$ 9.63	$ 12.79
2031	$ 7.08	$ 9.63	$ 12.79
2032	$ 7.08	$ 9.63	$ 12.79
2033	$ 7.08	$ 9.63	$ 12.79
2034	$ 7.08	$ 9.63	$ 12.79
2035	$ 7.08	$ 9.63	$ 12.79
2036	$ 7.08	$ 9.63	$ 12.79
2037	$ 7.08	$ 9.63	$ 12.79
2038	$ 7.08	$ 9.63	$ 12.79
2039	$ 7.08	$ 9.63	$ 12.79
2040	$ 7.08	$ 9.63	$ 12.79
2041	$ 7.08	$ 9.63	$ 12.79
2042	$ 7.08	$ 9.63	$ 12.79
2043	$ 7.08	$ 9.63	$ 12.79
2044	$ 7.08	$ 9.63	$ 12.79
2045	$ 7.08	$ 9.63	$ 12.79
Levelized (a)			
2016-2025	$5.72	$8.05	$10.50
2016-2030	$6.00	$8.40	$11.05
2016-2045 (b)	$6.44	$8.90	$11.76

Notes

(a)	Real discount rate:	2.43%
(b)	Values 2031-2045 extrapolated per Compound Annual Growth Rate from 2021 to 2030	
(c)	Distribution system losses	2%

Exhibit C-15

Avoided Cost of Gas to Retail Customers by Costing Period - Northern New England (NH, ME), 2015$ per MMBtu

Assumes 2% Distribution System Losses and zero Avoidable Retail Margin

(2015$ per MMBtu)

Costing period	Shoulder / summer	Remaining Winter	Peak Days
Days	**214**	**141**	**10**
Year			
2015	$ 4.12	$ 7.69	$ 10.91
2016	$ 4.64	$ 8.42	$ 8.47
2017	$ 5.70	$ 9.33	$ 9.68
2018	$ 5.98	$ 9.78	$ 10.36
2019	$ 5.86	$ 13.68	$ 10.62
2020	$ 5.48	$ 13.30	$ 10.19
2021	$ 5.78	$ 13.67	$ 10.81
2022	$ 5.87	$ 13.77	$ 10.97
2023	$ 5.95	$ 13.88	$ 11.12
2024	$ 6.14	$ 14.13	$ 11.60
2025	$ 6.24	$ 14.24	$ 11.77
2026	$ 6.35	$ 14.38	$ 12.03
2027	$ 6.44	$ 14.49	$ 12.18
2028	$ 6.54	$ 14.60	$ 12.32
2029	$ 6.73	$ 14.79	$ 12.51
2030	$ 7.01	$ 15.07	$ 12.79
2031	$ 7.01	$ 15.07	$ 12.79
2032	$ 7.01	$ 15.07	$ 12.79
2033	$ 7.01	$ 15.07	$ 12.79
2034	$ 7.01	$ 15.07	$ 12.79
2035	$ 7.01	$ 15.07	$ 12.79
2036	$ 7.01	$ 15.07	$ 12.79
2037	$ 7.01	$ 15.07	$ 12.79
2038	$ 7.01	$ 15.07	$ 12.79
2039	$ 7.01	$ 15.07	$ 12.79
2040	$ 7.01	$ 15.07	$ 12.79
2041	$ 7.01	$ 15.07	$ 12.79
2042	$ 7.01	$ 15.07	$ 12.79
2043	$ 7.01	$ 15.07	$ 12.79
2044	$ 7.01	$ 15.07	$ 12.79
2045	$ 7.01	$ 15.07	$ 12.79
Levelized (a)			
2016-2025	$5.74	$12.29	$10.50
2016-2030	$6.00	$12.99	$11.05
2016-2045 (b)	$6.41	$13.84	$11.76

Notes

(a)	Real discount rate:	2.43%
(b)	Values 2031-2045 extrapolated per Compound Annual Growth Rate from 2021 to 2030	
(c)	Distribution system losses	2%