Paul A. Colbert
Associate General Counsel
Regulatory Affairs

December 1, 2016

Hon. Kathleen H. Burgess
Secretary to the Commission
New York State Public Service Commission
Agency Building 3
Albany, NY 12223-1350

Re: Case 15-E-0186 - *Petition Effectuating Dynamic Load Control and Commercial System Relief Program Tariff Changes for the Summer of 2016*

Case 14-E-0423 - *Proceeding on Motion of the Commission to Develop Dynamic Load Management Program*

Case 14-E-0318 - *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service*

Dear Secretary Burgess:

Central Hudson Gas & Electric Corporation submits for filing in the above-referenced cases its Dynamic Load Control ("DLC") and Commercial System Relief Program ("CSRP") Annual Report and Petition Effectuating Tariff Changes for the Summer of 2017, with 2016 Results for the Targeted Demand Response Program, a Central Hudson Non-Wires Alternative. This filing is in compliance with the Order Adopting Dynamic Load Management Program Changes with Modifications and the Order Adopting Dynamic Load Management Filings with Modifications, issued and effective May 23, 2016 and June 18, 2015 respectively, by the New York State Public Service Commission.

Please contact the undersigned or Mark Sclafani, Senior Program Coordinator–Demand Response, Energy Transformation & Solutions at (845) 486-5979 or msclafani@cenhud.com with any questions regarding this matter.

Respectfully submitted,

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs	**Case 14-E-0423**
Petition by Central Hudson Gas & Electric Corporation to Effectuate Dynamic Load Management Programs	**Case 15-E-0186**
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	**Case 14-E-0318**

Central Hudson Gas & Electric Corporation's Dynamic Load Control (DLC) and Commercial System Relief Program (CSRP) Annual Report and Petition Effectuating Tariff Changes for the Summer of 2017, with 2016 Results for the Targeted Demand Response Program a Central Hudson Non-Wires Alternative

December 1, 2016

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
284 South Avenue
Poughkeepsie, N.Y. 12601

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1. Background

As part of the Reforming the Energy Vision ("REV") proceeding[1], the Commission initiated the instant proceeding on December 15, 2014, directing all electric utilities without dynamic load management ("DLM") programs to develop and file draft tariffs providing for the implementation of such programs for the summer of 2015[2].

Central Hudson Gas & Electric Corporation ("Central Hudson" or "the Company") submitted its proposed DLM programs in a draft tariff filing on March 23, 2015. Subsequently, on June 18, 2015, the Commission issued an order ("June 18th Order") approving Central Hudson's DLM programs with modifications and directing further filings.[3] Among the directed further filings was the requirement that each utility "perform assessments of the performance and cost-effectiveness of their individual DLM programs after each summer capability period"[4] and file a report on or before December 1 of each year detailing such evaluation ("December 1st Report"), as well as a Petition effectuating tariff changes for the summer of 2016 ("Petition") before January 7th, 2016.

Pending the results of a marginal distribution cost study, which the Company was directed to develop and utilize for designing "respective DLM program payment structures for the summer of 2016," the Company requested an extension for the Petition filing. The extension was approved on December 31, 2015 in the Notice Extending Deadline to File, and a new deadline of February 16, 2016

[1] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015).
[2] Case 14-E-0423, Dynamic Load Management Programs, Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings ("December 15th Order") (issued December 15, 2014).
[3] Case 14-E-0423, et al., supra, Order Adopting Dynamic Load Management Filings with Modifications ("June 18th Order") (issued June 18, 2015).
[4] Id, p. 7.

was issued. For the February 16, 2016 filing, the marginal distribution costs results utilized were preliminary. These results were further refined for the inclusion in the company's Initial Distributed System Implementation Plan ("DSIP")[5] and Benefit-Cost Analysis ("BCA")[6] Handbook.

In the Order Adopting Dynamic Load Management Program Changes with Modifications, issued and effective May 23, 2016[7] ("May 23rd Order") the Commission directed The Utilities to make various changes to the DLM programs and report on certain additional program aspects within this annual report. Results from the 2016 program season, and revised BCA analysis are included herein. Based on these results, Central Hudson has proposed various changes to improve the DLM program.

On July 15, 2016 the Commission issued an Order ("July 15th Order")[8] concerning Central Hudson's Non-Wires Alternative project in which the Central Hudson was ordered to "develop an operating procedure for the calculation of the financial incentive, including the milestones, as described in the body of this Order and file such procedure within 30 days of the issuance of this Order." [9]The Company subsequently requested an extension of the filing deadline to September 15, 2016, which was granted. In the Operation Procedure for NWA Incentives[10] ("Operation Procedure"), the Company detailed key NWA results which would be provided to Staff each year on December 1st. Those results have been included within Appendix A of this filing.

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[5] Case 14-M-0101 Reforming the Energy Vision: filed on June 30th 2016.
[6] Case 16-M-0412 Benefit-Cost Analysis Handbooks, initially filed on May 30th 2016, subsequent revision filed August 30th 2016.
[7] Case 14-E-0423, Dynamic Load Management Programs, Order Adopting Dynamic Load Management Program Changes with Modifications ("May 23rd Order") (issued May 23rd 2016).
[8] Case 14-E-0318, Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, Order implementing with Modification The Proposal for Cost Recovery and Incentive Mechanism for Non-Wire Alternative Project ("July 15th Order") (issued July 15th 2016).
[9] July 15th Order, p. 14.
[10] Case 14-E-0318, et al., supra, filed on September 15, 2016.

2. 2016 Program Results

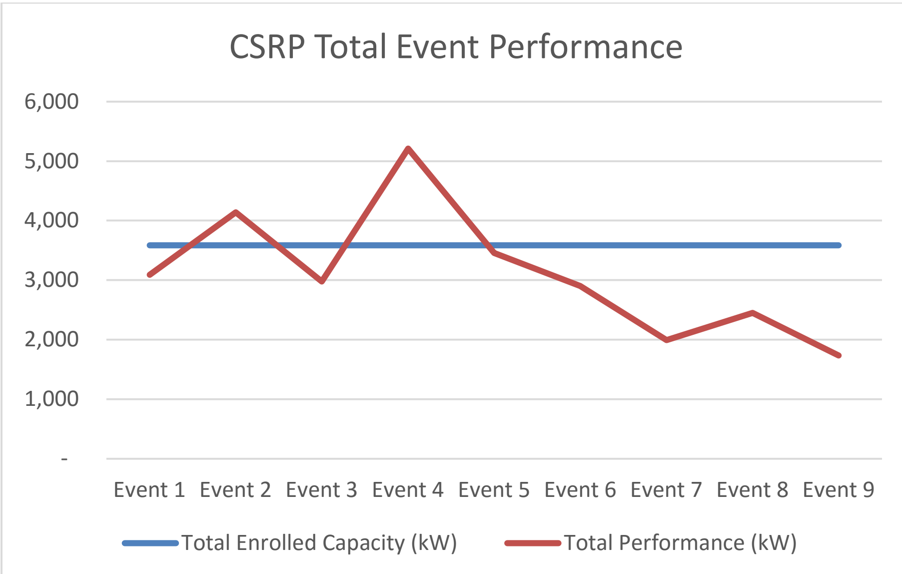
Commercial System Relief Program

In 2016, thirteen customers participated in the CSRP for the duration of the program season, most enrolling through an aggregator. There were two additional customers who enrolled, but left the program early in the season. Enrolled curtailments from the remaining thirteen customers totaled 3,588 kW. Based on day-ahead system load forecasts, Central Hudson dispatched 9 events throughout the season, for a total of 35 dispatch hours.

Table 1: CSRP Event History

Date	Start Time	End Time	Total Enrolled Capacity (kW)	Total Performance (kW)	Performance Factor
7/6/2016	4:00 PM	7:00 PM	3,588	3,092	86%
7/7/2016	3:00 PM	7:00 PM	3,588	4,137	115%
7/15/2016	3:00 PM	7:00 PM	3,588	2,979	83%
7/25/2016	3:00 PM	7:00 PM	3,588	5,212	145%
8/11/2016	3:00 PM	7:00 PM	3,588	3,457	96%
8/12/2016	3:00 PM	7:00 PM	3,588	2,902	81%
8/15/2016	3:00 PM	7:00 PM	3,588	1,993	56%
8/16/2016	3:00 PM	7:00 PM	3,588	2,449	68%
8/26/2016	1:00 PM	5:00 PM	3,588	1,735	48%
Average			**3,588**	**3,106**	**87%**

Figure 1: CSRP Portfolio Performance



On two occasions, the CSRP portfolio outperformed the enrolled level of capacity. Closer examination revealed that this excess is mainly due to the over performance of one particular customer. Apart from these anomalies, there was a downward performance trend throughout the control season. This trend concurs with customer and aggregator feedback as discussed further below.

Direct Load Control Program

The Direct Load Control Program had no participation in 2016. The program has been available since April 4, 2016 with easy avenues to enroll via www.CenHubPeakPerks.com and the CenHub Store[11].

[11] https://www.cenhubstore.com/collections/wi-fi-thermostats/products/cenhub-intellitemp-thermostat

3. BCA Analysis

Central Hudson performed a BCA analysis of the DLM programs, using the protocols outlined in Central Hudson's BCA handbook, version 1.1[12]. Neither the CSRP nor the DLC program had a favorable BCA result in 2016, however there are opportunities to improve benefit-cost of the CSRP through optimizing program design.

Central Hudson did not consider avoided Generation Capacity Costs (GCC) as a benefit for the CSRP since these benefits are adequately accounted for through participation in the NYISO's demand response programs. The primary benefit produced by the CSRP is avoided transmission and distribution (T&D) infrastructure costs. Although the 2016 program did not achieve a positive benefits to costs ratio within the existing BCA framework, the Company has laid out a path to optimize the program's cost effectiveness through various program changes. Through reduced incentive payments, shortened control season, and elevated dispatch threshold, the Societal Cost Test ("SCT")[13] score should improve from 0.43 to 1.06.[14]

[12] Case 16-M-0412 Benefit-Cost Analysis Handbooks, initially filed on May 30th 2016, subsequent revision filed August 30th 2016.
[13] As defined within Central Hudson's Benefit-Cost Analysis Handbook
[14] The resulting Utility Cost Test and Ratepayer Impact Measure ratios would be 1.04 and 1.02 respectively.

Table 2: BCA Societal Cost Test Results

Program[15]	CSRP, Actual 2016	CSRP, 2017 (As Proposed)	DLC, 2017 (As Designed)
Enrollment (kW)	3,588	7,000	200
Performance Factor	87%	87%	75%
Reservation Payments ($)	$51,795	$48,720	$0
Performance Payments ($)	$28,412	$13,703	$0
Total Incentives ($)	$80,207	$62,423	$5,000
Net Participant DER Cost ($)	$0	$0	$32,000
Program Administration Cost ($)	$50,000	$35,000	$75,000
Total Avoided GCC ($)	$0	$0	$13,889
Total Avoided T&D ($)[16]	$48,261	$94,154	$2,340
Total Avoided LBMP ($)	$6,113	$7,261	$176
Total Avoided Net CO2 ($)	$1,987	$1,650	$41
Total Costs	**$130,207**	**$97,423**	**$112,000**
Total Benefits	**$56,361**	**$103,065**	**$16,446**
Net Benefits	**($73,846)**	**$5,642**	**($95,554)**
SCT BC Ratio	**0.43**	**1.06**	**0.15**

Detailed BCA Assumptions and Results have been included as Appendix B to this document.

[15] With no participation in the DLC program in 2016 and no associated benefits, no meaningful BCA analysis could be performed.
[16] Avoided T&D benefits are calculated as prescribed within the Company's BCA Handbook, with values sourced from The Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, filed as Appendix D within the Company's DSIP.

4. CSRP Stakeholder Feedback

In an effort to optimize the customer experience of the CSRP program, Central Hudson solicited feedback from all program aggregators and direct participants at the end of the program season. Through in person meetings, phone calls, and email correspondence, discussions took place with all aggregators and direct customers. Several common experiences and recommendations for improvement emerged:

Dispatch Frequency / Threshold: All stakeholders agreed that events occurred too frequently throughout the 2016 season, and that fatigue led to reduced performance or satisfaction with the program. One aggregator stated that they will not recommend that their customers participate in this program in 2017 unless the threshold for dispatching events is changed. Central Hudson agrees that the dispatch threshold needs to be re-evaluated for the program to remain viable.

Event Dispatch: Most stakeholders thought Central Hudson's event dispatch communications were clear and effective. One stakeholder commented that they would prefer to receive a day-ahead advisory that an event is possible, then receive a confirmation of an event 2-3 hours before the start. Other stakeholders preferred the existing approach of providing official notification of an event 21 hours in advance.

Enrollment Process: Several stakeholders commented that the PDF enrollment form was inefficient, requesting instead to have an automated portal or spreadsheet enrollment form. Central Hudson agrees with this change and intends to revise the enrollment form into an Excel format for ease of enrolling multiple customers at once.

Timeliness of Performance Feedback: Several stakeholders would have preferred to receive event performance results in a more timely fashion. Central Hudson agrees that this process could be improved, and has contracted with a 3rd party consultant to calculate more timely performance results which can be provided to participants regularly throughout the 2017 control season.

Better Availability of Program Information: A few stakeholders commented that there is a lack of program information available online, and that the tariff language may leave certain aspects of the program up to interpretation. For example, certain participants were unsure whether to expect that all events would be the same duration, or would follow the same call window. Central Hudson proposes to clarify this procedure where possible, and provide additional detailed information regarding the DLM programs on a newly designed web page, set to go live before 2017 as discussed below.

Simplification of Settlement: A few stakeholders commented that the current settlement procedure is overly complex. A seasonal settlement was suggested as a way to streamline this process.

5. Proposed CSRP Program Changes

Central Hudson's BCA analysis does not indicate that it would be feasible to achieve a positive net result of benefits and costs of the DLC program within the existing BCA framework. However, the Company has laid out a plan to optimize the CSRP program's cost effectiveness by lowering certain program costs which are tied to specific rules within the program tariff. The following program changes are expected to improve the program's effectiveness and enhance the customer experience where possible.

CSRP Dispatch Threshold:

In the May 23rd Order, Central Hudson was directed to "make conforming tariff changes to adopt the 92% CSRP dispatch threshold," wherein CSRP events would be dispatched anytime the system-wide demand is forecast to reach at least 92% of the forecasted annual peak. As enumerated in the feedback provided by various stakeholders, frequent events throughout the 2016 season have led to fatigue and less than optimal performance. Central Hudson believes the event threshold should be calibrated to a level which results in a reasonable curtailment expectation while preserving the ability of the program to provide marginal grid value. In the Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, published October 27th, 2016, Staff proposed a method for valuing demand reducing resources: stating that "The resulting $ per kW year will be distributed across the ten highest usage hours in a utility's territory and generators will be compensated based on their performance during those hours."[17] This logic implies that the demand reduction value of a resource can be reasonably captured by evaluating its contribution during the ten highest usage hours of the year. Central Hudson believes that a consistent design criterion can be utilized to set the CSRP event threshold; as the program should be designed to generate a reduction in demand during these ten hours. An analysis of historical hourly system demand reveals the threshold that would have coincided with the highest ten usage hours for each of the past ten years.

[17] Case 15-E-0751 Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding, filed October 27th 2016.

Table 3: Historical System Demand Analysis

Year	Peak Hour (MW)	10th Highest Hour (MW)	Threshold	Number of Events	Total Dispatch Hours[18]
2006	1,295	1,263	97.5%	3	15
2007	1,185	1,170	98.7%	4	20
2008	1,187	1,146	96.5%	2	10
2009	1,107	1,080	97.6%	3	12
2010	1,229	1,172	95.4%	2	10
2011	1,224	1,182	96.6%	2	10
2012	1,168	1,108	94.9%	5	20
2013	1,203	1,162	96.6%	3	15
2014	1,058	1,010	95.5%	3	15
2015	1,059	1,037	97.9%	4	20
2016	1,077	1,037	97.3%	3	15
10-Year Average	**1,163**	**1,125**	**96.8%**	**3.09**	**15**

Based on this analysis, Central Hudson proposes to use a threshold of 97% of forecasted summer peak as a threshold for triggering CSRP events. This threshold would result in an average of approximately three events per season with fifteen total curtailment hours. A 97% threshold is also forecast to result in approximately 25% reduction in overall incentive costs. A dispatch threshold below 97% would have a tendency to be counterproductive towards optimizing the program; raising program costs, increasing participant fatigue; and lowering overall performance without an associated increase in benefit.

Eliminating May from CSRP Summer Capability Period:

In Central Hudson Gas & Electric Corporation's Petition Effectuating Dynamic Load Control (DLC) and Commercial System Relief Program (CSRP) tariff changes for the summer of 2016, Central Hudson proposed to shorten the capability period by changing the start date from 5/1 to 6/1. Central Hudson

[18] This analysis assumes an average event duration of 5 hours to coincide with the highest 10 load hours in years in which those hours are spread across only 2 days.

continues to believe this change will improve the cost benefit profile of the DLM program. Figure 4 below shows the 10-year historical peak during the month of May as compared to the associated annual peak. At no point in the last 10 years did the system demand exceed 88% of the annual peak during the month of May. On average, the highest load occurring during the month of May is only 79% of the associated annual peak. These data show that curtailment events are highly unlikely to occur during the month of May under any of the dispatch thresholds that have been considered thus far. The reduced reservation payments resulting from this change would eliminate approximately 17% of program costs with no associated loss in benefits.

Table 4: Historical Peak Demand during May

Year	Annual Peak Hour	May Peak Hour	Percentage
2006	1,295	996	77%
2007	1,185	976	82%
2008	1,187	814	69%
2009	1,107	800	72%
2010	1,229	1,021	83%
2011	1,224	964	79%
2012	1,168	1,033	88%
2013	1,203	1,016	84%
2014	1,058	771	73%
2015	1,059	865	82%
2016	1,077	878	82%
		Average	**79%**

Changes to Program Payment Structure

Central Hudson performed a sensitivity analysis to develop a cost effective program incentive structure. To produce a passing SCT score within the CSRP program, the program incentives would need to be reduced by approximately 50%. Central Hudson proposes to reduce reservation payments and performance payments to $2.00/kW-month, and $0.15/kWh respectively. Under the forecasted enrollment levels for 2017, this would result in a BCA of 1.06. This result is valid only under the scenario that the dispatch threshold and capability period are amended in accordance with the recommendations above. Without those critical changes, the incentives would need to be further reduced to achieve a favorable BCA result.

Table 5: CSRP Payments

Existing Payments	Proposed Payments
***Reservation*:** $4/kW/month for 4 or less planned events; $5/kW/month for 5+ planned events; Performance: $0.25/kWh planned event; $0.50/kWh unplanned event ; ***Voluntary*:** $0.25/kWh four-hour planned event; $1.00/kWh unplanned event.	***Reservation*:** $2.00/kW/month for 4 or less planned events; $2.50/kW/month for 5+ planned events; Performance: $0.15/kWh planned event; $0.30/kWh unplanned event; ***Voluntary*:** **Eliminated**

It is unknown how this incentive level will affect future participation and performance. If participation decreases substantially, the program may no longer be viable after 2017. The company will re-evaluate incentives based on actual 2017 participation levels.

Allow for Aggregation of Multiple Accounts:

In the May 23rd Order, the Commission directed utilities to "examine and report, as part of the Utilities' annual reports, the changes necessary to allow customers to aggregate multiple accounts through the utility within the same service territory and make the necessary filing to effectuate such capabilities for 2017."[19] Central Hudson has contracted with a 3rd party consultant to provide analytical support in determining the performance of individual accounts. Due to the relatively small enrollment numbers in Central Hudson's CSRP program thus far, the enrollment, performance calculation, and settlement processes are largely manual. In the event that a customer desires to aggregate multiple accounts into a single settlement in 2017, Central Hudson can support this with a limited increase in administrative work. It should be noted however, that the enrollment threshold should remain at 50kW for each individual account to keep this aggregation of accounts manageable. Central Hudson is also not in a position to offer additional value-added services to CSRP participants, such as facility energy management or enrollment in a NYISO demand response program, which can currently be obtained through the various aggregators participating in the market.

Unplanned Event Provision:

An unplanned event is defined within the program tariff as "the Company's request for Load Relief: (a) on less than 21 hours' advance notice; or (b) for hours outside of the Contracted Hours."[20] Central Hudson proposes to implement the flexibility to refrain from dispatching unplanned events when operational parameters of the electric system do not indicate a capacity need. Unplanned events are

[19] May 23rd Order, p. 25.
[20] P.S.C. No. 15 – Electricity, 2nd Revised leaf No. 163.5.41.

more disruptive to participants, and bear a higher incentive cost. These events should be avoided unless they are deemed necessary based on current system conditions.

Eliminate Voluntary Payment Option (VPO):

In the May 23rd Order, the Commission directed Central Hudson to "make tariff changes in compliance with this Order to eliminate the CSRP penalty provision from its CSRP tariff."[21] Central Hudson has eliminated all penalty provisions from the program, beginning with the 2016 season. The VPO was originally designed to be a lower incentive offer than the Reservation Payment Option (RPO), which would be offset by the avoidance of non-performance penalties. With the elimination of penalties from the RPO, the VPO is no longer necessary. Central Hudson proposes to eliminate this option; simplifying enrollment and ensuring that customers are directed to the most advantageous option. No customers participated in the VPO in 2016.

Annual Settlement:

Central Hudson proposes to simplify the performance settlement process by moving from monthly to annual settlements as detailed below:

- Aggregators and direct participants will be provided one seasonal reservation & performance payment after the end of the capability period.
- Reservation payments will be based on the average performance factor of all load relief hours within the capability period

[21] May 23rd Order, p. 30.

- Aggregators and direct participants will receive monthly performance reports which detail the performance during each event within that month.

Annual settlement will eliminate the need to distribute partial reservation payments in months where no events occur, followed by performance true-ups which could be positive or negative. Aggregator feedback was generally favorable towards this approach as compared to the current settlement procedure.

6. Discontinuation of the DLC Program

Based on the lack of participation in the DLC program and its poor BCA performance, Central Hudson proposes that this program be discontinued. Increased incentives and/or additional marketing initiatives would be required to make this program successful, neither of which can be cost-justified by the marginal benefits of the DLC program. As such, the Company does not see a viable path to make this program cost effective. Since there are currently no participants in the DLC program, the program ramp down would be relatively simple. If any customers do enroll before the program is cancelled, the Company would plan to honor their sign-up payment of $25. Additionally, Central Hudson is currently refining its optional time-of-use rate which will establish a more effective way to engage residential customers in peak demand reduction, planned for June of 2017.

7. Program Website

In the May 23rd Order, the Commission directed utilities to "revise their respective websites to improve customers' and aggregators' ability to find basic program information, explanation of program rules, links to the Utilities respective tariffs, and information regarding how to enroll in the DLM

Programs."[22] The Commission also encouraged utilities to "refer to Con Edison's website as an example of how to better present information related to the DLM Programs."[23]

Central Hudson has developed an intuitive website which contains all pertinent DLM program information. Although the layout of the site is different from Con Edison's, Central Hudson consulted with Con Edison staff, and used their website as a guide in some instances. The new web page will be integrated with Central Hudson's Energy Efficiency and other Demand Response program offerings (i.e. Targeted Demand Response) to create an easily navigable catalog of all available offerings by customer segment. This web page is expected to go live before the end of 2016. Where applicable, the Central Hudson site will redirect to 3rd party web pages, such as www.CenHubPeakPerks.com. Figures 2 & 3 below illustrate the draft content and layout of certain demand response pages.

[22] May 23rd Order, p. 26.
[23] Id.

Figure 2: Residential & Small Commercial Demand Response Landing Page:

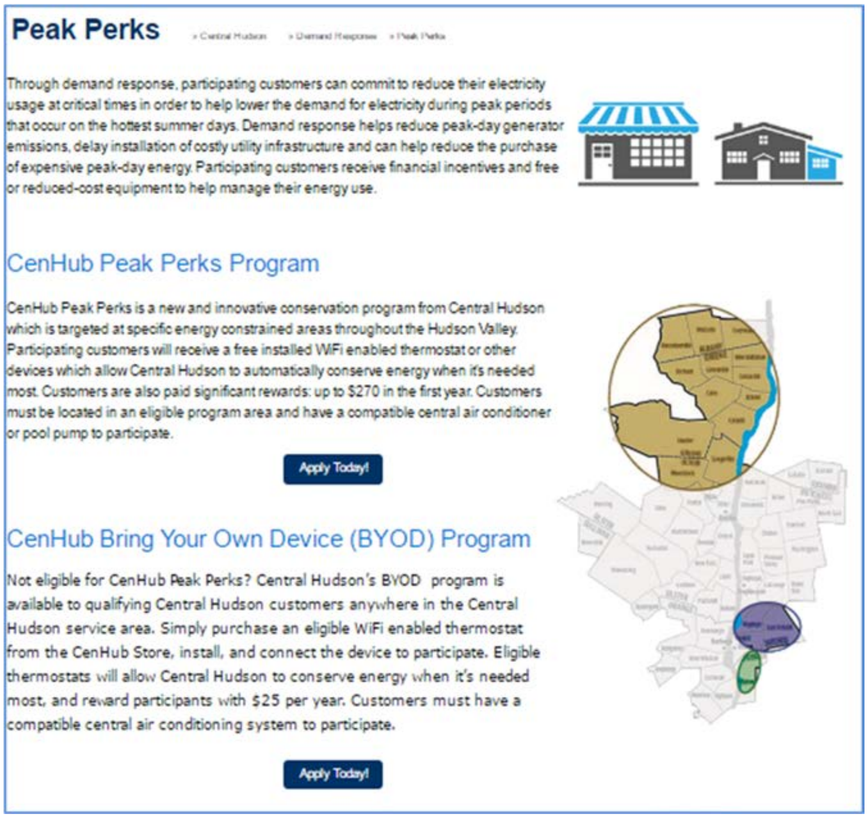


Figure 3: Portion of Commercial System Relief Program Page:

Commercial System Relief Program (CSRP):

Through the CSRP program, participating commercial & industrial customers anywhere in the Central Hudson service territory can commit to reduce their electricity usage at critical times in order to help lower the demand for electricity during peak periods when energy use is at its highest. Participants are paid incentives based on how much load reduction they provide. There are two enrollment options within the CSRP program, the reservation payment option & the voluntary payment option.

Apply Today!

Central Hudson Commercial System Relief Program Incentives

Enrollment Option	Hours of notification Before Planned DR Events	Monthly Reservation Payment Rate	Performance Payment Rate During DR Events
Reservation Payment Option	21 Hours or Greater	$4 / KW / Month	$0.25 / kWh for Planned Events
			$0.50 / kWh for Unplanned Events
Voluntary Payment Option	21 Hours or Greater	None	$0.25 / kWh for Planned Events
			$1.00 / kWh for Unplanned Events

If 5 or more events are called in any control season, the Reservation Payment is increased to $5 / kW / month starting with the month with the 5th event through the end of September.

Participant incentives are paid based on actual seasonal-average reductions, calculated using the customer base load (CBL) baseline methodology. For more details, see the CSRP Program Measurement & Verification Methodology.

8. Conclusions

Within this annual report on the Dynamic Load Management program, Central Hudson has compiled 2016 results, stakeholder feedback, and the BCA analysis which incorporated pertinent historical system data. Based on these results, it can be reasonably concluded that the DLC program is not viable in Central Hudson's service territory, and its discontinuation is proposed. Although the CSRP was not cost effective in 2016 under the existing program constructs, the Company has proposed strategic changes to maximize the program's benefit-cost profile. Where possible, the Company has proposed to streamline processes and improve customer experience. Because the margin of cost-effectiveness for the redesigned CSRP program remains quite small, the viability for the program depends upon the adoption of three critical program cost-reducing measures proposed within this document:

- Raising the dispatch threshold to 97% of forecasted annual peak
- Eliminating May from the capability period
- Reducing reservation & performance payments as detailed.

Exclusion of any one of these three strategic changes would require an associated recalibration of the other two. Because the impact on participation is currently unknown, the viability of the program will need to be re-evaluated based on 2017 program results. In the absence of these corrective actions, Central Hudson believes the program should be discontinued.

Appendix A: Targeted Demand Response Program 2016 Results

As described within Section 1 of this filing, the Company's, Operation Procedure detailed key NWA results which would be provided to Staff each year on December 1st. 2016 Results for Central Hudson's NWA, also known as the Targeted Demand Response Program, have been included in this Appendix.

Residential / Small Commercial Event Day Details

For the 2016 curtailment season, there were a total of five curtailment event days where the September 2016 events were test events. All times are presented in Eastern Daylight Time (EDT). Table also provides notes on the events to highlight anything that was outside of the normal event operation during that event.

Table A-1: Event Dates Summary

Date	Start Time (EDT)	End Time (EDT)	Targets	Notes
07/15/16	5:00 PM	6:00 PM	TDM	
07/28/16	5:00 PM	6:00 PM	TDM	
08/12/16	2:00 PM	6:00 PM	TDM	Node 8095 excluded
09/06/16	3:30 PM	5:00 PM	TDM	Node 8091 residential thermostats only. Test event
09/08/16	4:30 PM	6:00 PM	TDM	Thermostats only. Test event

Figures A-1 through A-4 show the unadjusted baseline kW load, the event day kW load, and the adjusted baseline kW load for each event day for the *Residential* segment. The yellow-shaded area identifies the event time period. Figure A-5 to Figure A-8 present the event data for the *Small Commercial* segment. Data for the test event on September 6, 2016 is not presented as the event was only to a small group and was used to validate a change in a thermostat setting.

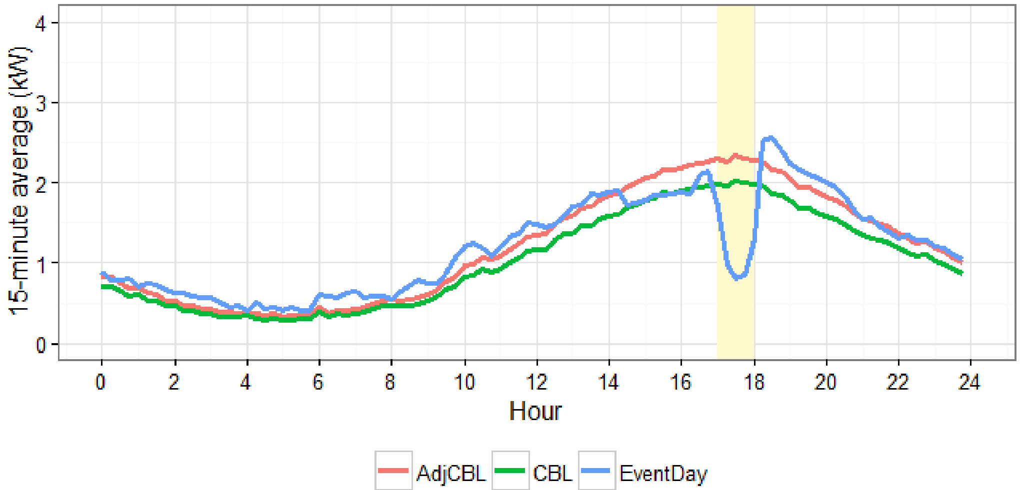


Figure A-1: Residential M&V Load July 15, 2016

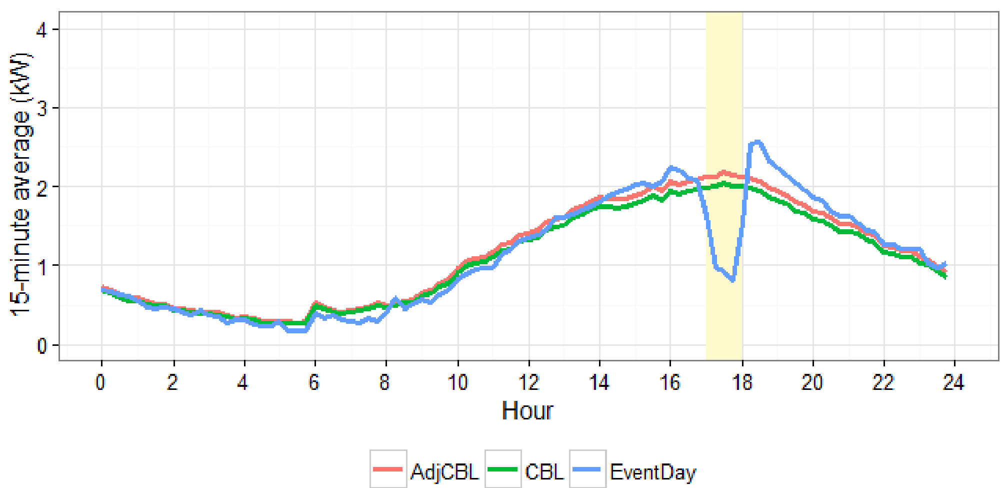


Figure A-2: Residential M&V Load July 28, 2016

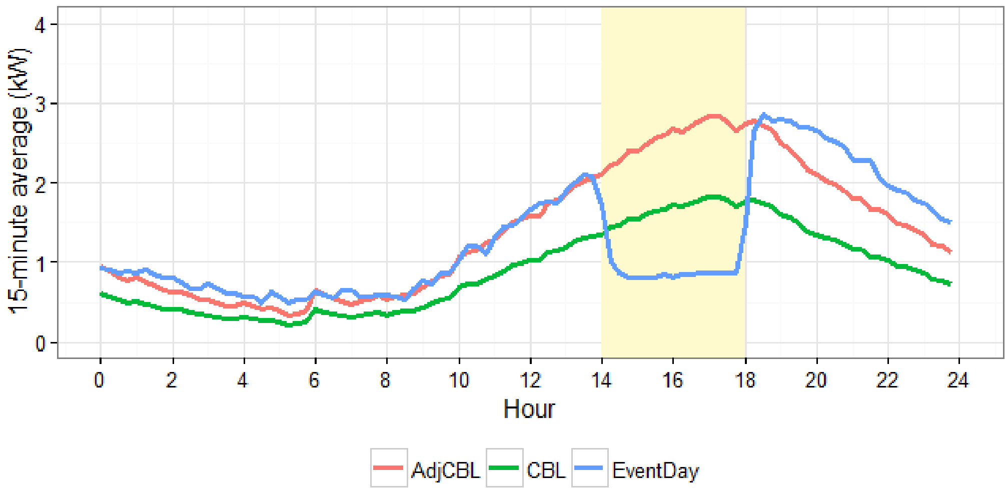


Figure A-3 Residential M&V Load August 12, 2016

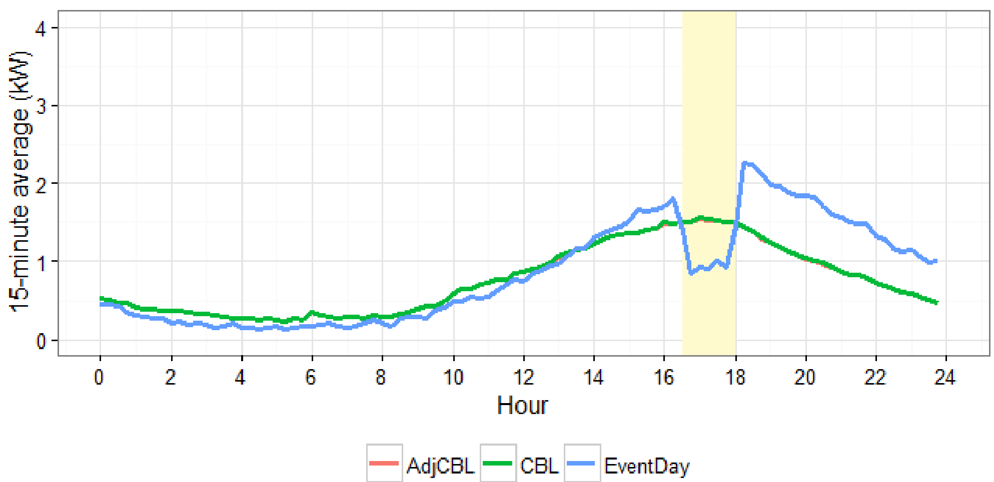


Figure A-4 Residential M&V Load September 8, 2016

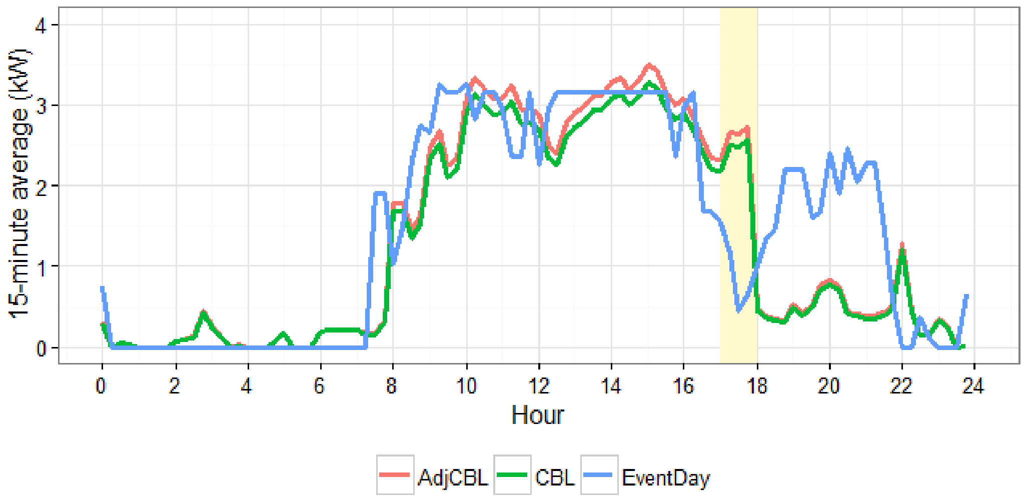


Figure A-5: Small Commercial M&V Load July 15, 2016

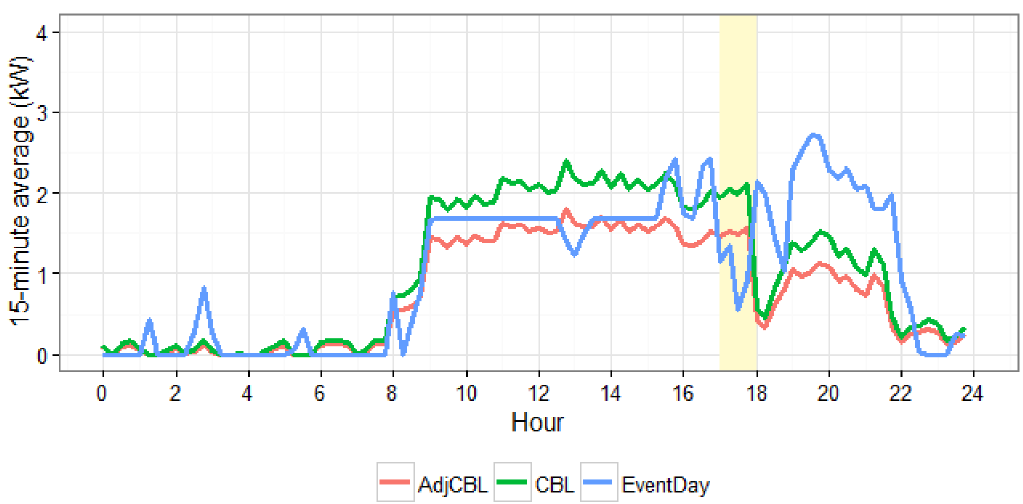


Figure A-6: Small Commercial M&V Load July 28, 2016

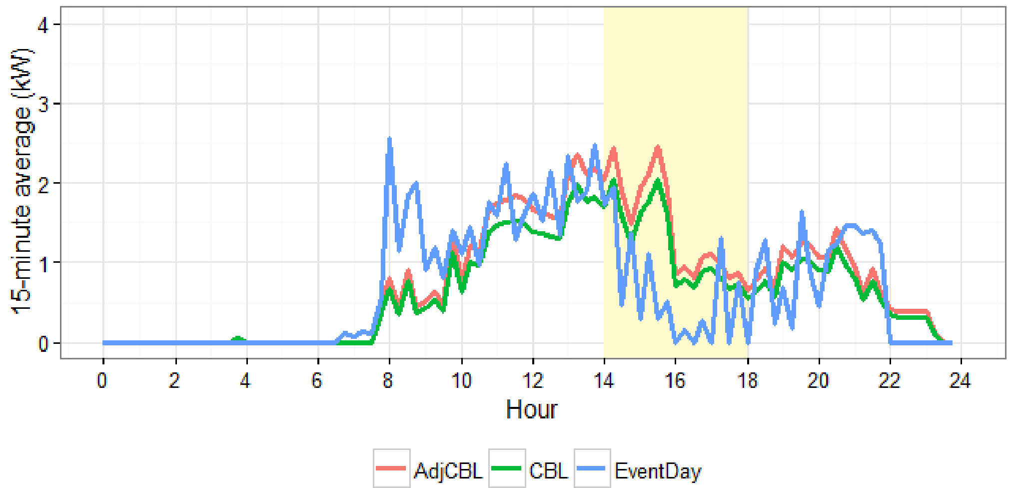


Figure A-7 Small Commercial M&V Load August 12, 2016

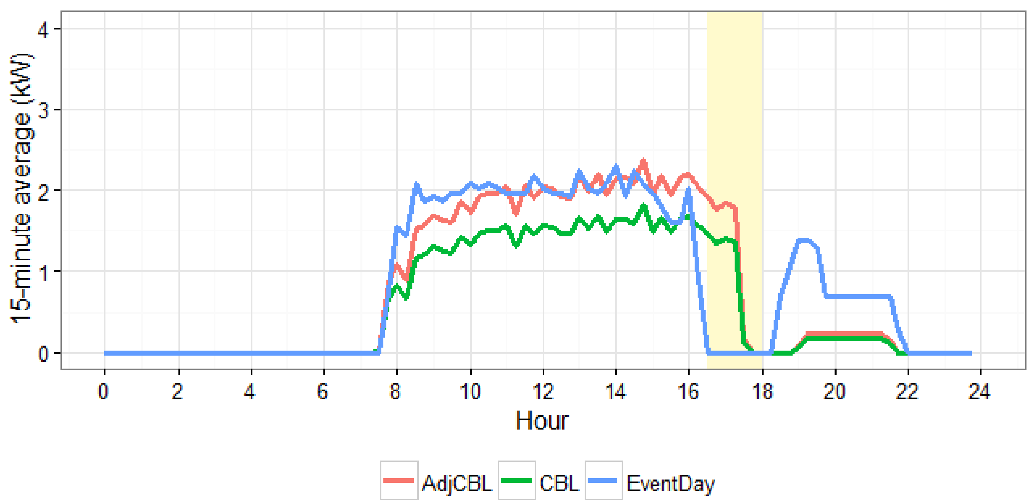


Figure A-8 Small Commercial M&V Load September 8, 2016

Residential / Small Commercial Load Reduction Results

The *Residential* segment load reduction estimates in 2016 were calculated for each event hour initiated by CHGE during the summer. The reduction for each 15-minute interval during the hour is estimated by taking the difference between the adjusted baseline and the portfolio load. After each event, a vigorous data validation process was performed, and any necessary adjustments to the data based on blackouts, incorrect wiring, or other scenarios that would affect data quality were made. Table A-2 summarizes the *Residential* segment load reduction results for each event hour. Note that the maximum 15-minute reduction in each event hour is listed.

Table A-2: Residential Summary of 2016 Events

Date	Start Time (EDT)	End Time (EDT)	Temp (°F)	Max 15-min Reduction Baseline Adjustment Method (kW)	Hourly Average
07/15/16	17:00	18:00	91	1.53	1.22
07/28/16	17:00	18:00	93	1.33	1.05
08/12/16	14:00	15:00	93	1.59	1.15
08/12/16	15:00	16:00	93	1.75	1.69
08/12/16	16:00	17:00	92	1.91	1.85
08/12/16	17:00	18:00	90	1.97	1.91
09/08/16	16:30	17:00	89	0.65	
09/08/16	17:00	18:00	90	0.62	0.58

Using the adjusted baseline approach, the maximum qualifying 15-minute reduction for the curtailment season was 1.97 kW and it occurred on August 12, 2016 for the 5PM hour.

Table A-3 summarizes the *Small Commercial* segment load reduction results for each event hour.

Table A-3: Small Commercial Summary of 2016 Events

Date	Start Time (EDT)	End Time (EDT)	Temp (°F)	Max 15-min Reduction Baseline Adjustment Method (kW)	Hourly Average
07/15/16	17:00	18:00	91	2.19	1.63
07/28/16	17:00	18:00	93	0.93	0.52
08/12/16	14:00	15:00	93	1.44	0.59
08/12/16	15:00	16:00	93	2.17	1.56
08/12/16	16:00	17:00	92	0.86	0.81
08/12/16	17:00	18:00	90	1.11	0.42
09/08/16	16:30	17:00	89	1.92	
09/08/16	17:00	18:00	90	1.84	0.95

Using the adjusted baseline approach, the maximum qualifying 15-minute reduction for the curtailment season was 2.19 kW and it occurred on July 15, 2016 for the 5PM hour.

Large Commercial and Industrial (C&I) Event Day Details

For the 2016 curtailment season, there was one test event per region. All times are presented in Eastern Daylight Time (EDT). Table also provides notes on the events to highlight anything that was outside of the normal event operation during that event.

Table A-4: C&I Event Dates Summary

Date	Start Time (EDT)	End Time (EDT)	Notes
08/09/16	2:30 PM	3:30 PM	C&I Northwest Corridor
08/09/16	3:30 PM	4:30 PM	C&I Merritt Park
08/09/16	4:30 PM	5:30 PM	C&I Fishkill
09/08/16	3:00 PM	4:00 PM	C&I Fishkill retest

Table A-5 summarizes the C&I population load reduction results for each event hour.

Table A-5: C&I Summary of 2016 Events

Date	Start Time (EDT)	End Time (EDT)	Zone[24]	CBL (kW)	Event Hour Usage (kW)	Load Reduction (kW)
08/09/16	2:30 PM	3:30 PM	NW Corridor	4112	434	3679
08/09/16	4:30 PM	5:30 PM	Fishkill	154	100	54
09/08/16	3:00 PM	4:00 PM	Fishkill	221.7	5.5	216.2

A retest was performed in Fishkill due to under-performance by customers in the later hours of the day. The results of the initial test and re-test were used to simulate performance as it would occur during a curtailment event over the hours of 3PM -7PM, which is consistent with the historical temporal capacity need in this location. The resulting reduction is 77kW. Table A-6 presents the simulated results.

Table A-6: C&I Fishkill Retest 4 Hour Event Simulated Results

Hour Ending	CBL (kW)	Event Hour Usage (kW)	Load Reduction (kW)
4:00 PM	221.7	5.5	216.2
5:00 PM	98.0	5.3	92.7
6:00 PM	3.7	4.6	-0.9
7:00 PM	3.6	4.3	-0.7
Event Average	81.8	4.9	76.8

Final kW Calculation

For the 2016 curtailment season, there were a total of three curtailment events and two test events for the *Residential* and S*mall Commercial* populations. The maximum 15-minute reduction for the season based on qualifying event hours was 1.75 kW for the *Residential* population and 2.17 kW for the *Small Commercial* population. In addition, there was one event for the C&I population and a retest event for the C&I Fishkill population.

[24] As of 10/1/2016, there were no participating C&I customers in the Merritt Park zone.

Table A-7 through Table A-9 provide the MW reduction in each individual program zone, and Table A-10 provides the overall reduction for the program.

Table A-7: Summary of Reduction in Fishkill Zone

Population	Device	Active end points as of 10/01/16	Adjustment Factor	kW Factor (Max 15-minute)	kW Factor (Hourly Avg)	MW (Max 15-minute)	MW (Hourly Avg)
Residential	Thermostat - A/C	617	0.9	1.75	1.30	0.97	0.72
Residential	DCU - A/C	524	1.0	1.75	1.30	0.92	0.68
Small Commercial	Thermostat - A/C	30	0.9	2.17	0.89	0.06	0.02
Small Commercial	DCU - A/C	23	1.0	2.17	0.89	0.05	0.02
Large C&I						0.08	0.08
Total MW						**2.07**	**1.52**

Note: kW factors may be higher than expected due to thermostat lockout flag enable setting.
Note: DCU kW factor estimated from Thermostat kW factor.
Note: Adjustment factor of 0.9 applied to thermostats to account for offline devices.

Table A-8: Summary of Reduction in Merritt Park Zone

Population	Device	Active end points as of 10/01/16	Adjustment Factor	kW Factor (Max 15-minute)	kW Factor (Hourly Avg)	MW (Max 15-minute)	MW (Hourly Avg)
Residential	Thermostat - A/C	60	0.9	1.75	1.30	0.09	0.07
Residential	DCU - A/C	63	1.0	1.75	1.30	0.11	0.08
Small Commercial	Thermostat - A/C	5	0.9	2.17	0.89	0.01	0.00
Small Commercial	DCU - A/C	0	1.0	2.17	0.89	0.00	0.00
Large C&I						0.00	0.00
Total MW						**0.21**	**0.16**

Note: kW factors may be higher than expected due to thermostat lockout flag enable setting.
Note: DCU kW factor estimated from Thermostat kW factor.
Note: Adjustment factor of 0.9 applied to thermostats to account for offline devices.

Table A-9: Summary of Reduction in Northwest Corridor

Population	Device	Active end points as of 10/01/16	Adjustment Factor	kW Factor (Max 15-minute)	kW Factor (Hourly Avg)	MW (Max 15-minute)	MW (Hourly Avg)
Residential	Thermostat - A/C	16	0.9	1.75	1.30	0.03	0.02
Residential	DCU - A/C	5	1.0	1.75	1.30	0.01	0.01
Small Commercial	Thermostat - A/C	1	0.9	2.17	0.89	0.00	0.00
Small Commercial	DCU - A/C	0	1.0	2.17	0.89	0.00	0.00
Large C&I						3.68	3.68
Total MW						**3.72**	**3.71**

Note: kW factors may be higher than expected due to thermostat lockout flag enable setting.
Note: DCU kW factor estimated from Thermostat kW factor.
Note: Adjustment factor of 0.9 applied to thermostats to account for offline devices.

Table A-10: Summary of Overall Reduction

Population	Device	Active end points as of 10/01/16	Adjustment Factor	kW Factor (Max 15-minute)	kW Factor (Hourly Avg)	MW (Max 15-minute)	MW (Hourly Avg)
Residential	Thermostat - A/C	695	0.9	1.75	1.30	1.09	0.81
Residential	DCU - A/C	592	1.0	1.75	1.30	1.04	0.77
Small Commercial	Thermostat - A/C	36	0.9	2.17	0.89	0.07	0.03
Small Commercial	DCU - A/C	23	1.0	2.17	0.89	0.05	0.02
Large C&I						3.76	3.76
Total MW						**6.01**	**5.39**

Note: kW factors may be higher than expected due to thermostat lockout flag enable setting.
Note: DCU kW factor estimated from Thermostat kW factor.
Note: Adjustment factor of 0.9 applied to thermostats to account for offline devices.

This leads to 1.63 MW demand response reduction for the Residential and Small Commercial populations based on the total installed end points of 1,346 throughout the Central Hudson Peak Perks program service area and a 3.76 MW reduction for the Large C&I population.

Appendix B: Dynamic Load Management Benefit-Cost Analysis

DLM 2016 CSRP (Actual)

Program Details

Event Year	2016
Events in Year	9
kW Enrolled	3,588
Performance Factor	87%
Total Event Hours	35
Total System Losses	6.73%
Avoided GCC ($/kW)	$ -
Avoided T&D ($/kW)	$ 14.42
Avoided CO2 ($/MWh)	$ 16.96
Base Rate $/kWh	$ 0.02
Incentive $/Participant	$ -
DER $/Participant	$ -

Reservation Incentive Period	$/kW-Month
May-Jul	$ 4.00
Aug-Sep	$ 5.00

Performance Incentives	$ 28,412
Reservation Incentives	$ 51,795
Participant Incentives	$ -
Net Participant DER Cost	$ -
Program Administration Cost	$ 50,000
Lost Utility Revenue	$ 2,306
Shareholder Incentives	$ -
Total Avoided GCC ($)	$ -
Total Avoided T&D ($)	$ 48,261
Total Avoided LBMP ($)	$ 6,113
Total Avoided Net CO2 ($)	$ 1,987

	SCT	UCT	RIM
Total Costs	$ 130,207	$ 130,207	$ 132,514
Total Benefits	$ 56,361	$ 54,374	$ 54,374
Net Benefits	$ (73,846)	$ (75,833)	$ (78,140)
BC Ratio	**0.43**	**0.42**	**0.41**

Event Details

Event Number	Event Date	Event Start Hour	Event End Hour	Performance Incentive $/kWh	Total Avoided GCC ($)	Total Avoided T&D ($)	Total Avoided LBMP ($)	Total Avoided Net CO2 ($)
1	6-Jul-16	16	19	$ 0.25	$ -	$ -	$ 564	$ 170
2	7-Jul-16	15	19	$ 0.25	$ -	$ -	$ 649	$ 227
3	15-Jul-16	15	19	$ 0.25	$ -	$ -	$ 740	$ 227
4	25-Jul-16	15	19	$ 0.25	$ -	$ 48,261	$ 1,033	$ 227
5	11-Aug-16	15	19	$ 0.25	$ -	$ -	$ 643	$ 227
6	12-Aug-16	15	19	$ 0.25	$ -	$ -	$ 590	$ 227
7	15-Aug-16	15	19	$ 0.25	$ -	$ -	$ 650	$ 227
8	16-Aug-16	15	19	$ 0.25	$ -	$ -	$ 668	$ 227
9	26-Aug-16	13	17	$ 0.25	$ -	$ -	$ 577	$ 227

DLM 2017 CSRP (As Proposed)

Program Details

Event Year	2017
Events in Year	3
kW Enrolled	7,000
Performance Factor	87%
Total Event Hours	15
Total System Losses	6.73%
Avoided GCC ($/kW)	$ -
Avoided T&D ($/kW)	$ 14.42
Avoided CO2 ($/MWh)	$ 16.84
Base Rate $/kWh	$ 0.02
Incentive $/Participant	$ -
DER $/Participant	$ -

Performance Incentives	$ 13,703
Reservation Incentives	$ 48,720
Participant Incentives	$ -
Net Participant DER Cost	$ -
Program Administration Cost	$ 35,000
Lost Utility Revenue	$ 1,928
Shareholder Incentives	$ -
Total Avoided GCC ($)	$ -
Total Avoided T&D ($)	$ 94,154
Total Avoided LBMP ($)	$ 7,261
Total Avoided Net CO2 ($)	$ 1,650

	SCT	UCT	RIM
Total Costs	$ 97,423	$ 97,423	$ 99,351
Total Benefits	$ 103,065	$ 101,415	$ 101,415
Net Benefits	$ 5,642	$ 3,993	$ 2,064
BC Ratio	**1.06**	**1.04**	**1.02**

Reservation Incentive

Period	$/kW-Month
Jun-Sep	$ 2.00
	$ 2.50

Event Details

Event Number	Event Date	Event Start Hour	Event End Hour	Performance Incentive $/kWh	Total Avoided GCC ($)	Total Avoided T&D ($)	Total Avoided LBMP ($)	Total Avoided Net CO2 ($)
1	7-Jul-17	15	20	$ 0.15	$ -	$ -	$ 1,848	$ 550
2	15-Jul-17	15	20	$ 0.15	$ -	$ -	$ 2,151	$ 550
3	25-Jul-17	15	20	$ 0.15	$ -	$ 94,154	$ 3,261	$ 550

DLM 2017 DLC (As Designed)

Program Details

Event Year	2017
Events in Year	5
kW Enrolled	200
Performance Factor	75%
Total Event Hours	15
Total System Losses	6.73%
Avoided GCC ($/kW)	$ 86.36
Avoided T&D ($/kW)	$ 14.42
Avoided CO2 ($/MWh)	$ 16.84
Base Rate $/kWh	$ 0.07
Incentive $/Participant	$ 25
DER $/Participant	$ 185

Performance Incentives	$ -
Reservation Incentives	$ -
Participant Incentives	$ 5,000
Net Participant DER Cost	$ 32,000
Program Administration Cost	$ 75,000
Lost Utility Revenue	$ 150
Shareholder Incentives	$ -
Total Avoided GCC ($)	$ 13,889
Total Avoided T&D ($)	$ 2,319
Total Avoided LBMP ($)	$ 176
Total Avoided Net CO2 ($)	$ 41

	SCT	**UCT**	**RIM**
Total Costs	$ 112,000	$ 80,000	$ 80,150
Total Benefits	$ 16,425	$ 16,384	$ 16,384
Net Benefits	$ (95,575)	$ (63,616)	$ (63,766)
BC Ratio	**0.15**	**0.20**	**0.20**

Event Details

Event Number	Event Date	Event Start Hour	Event End Hour	Performance Incentive $/kWh	Total Avoided GCC ($)	Total Avoided T&D ($)	Total Avoided LBMP ($)	Total Avoided Net CO2 ($)
1	7-Jul-17	16	19	$ -	$ -	$ -	$ 28	$ 8
2	15-Jul-17	16	19	$ -	$ -	$ -	$ 33	$ 8
3	25-Jul-17	16	19	$ -	$ 13,889	$ 2,319	$ 52	$ 8
4	6-Jul-17	16	19	$ -	$ -	$ -	$ 32	$ 8
5	6-Jul-17	16	19	$ -	$ -	$ -	$ 32	$ 8

43. DIRECT LOAD CONTROL PROGRAM

Reserved for Future Use

43. DIRECT LOAD CONTROL PROGRAM (Cont'd)

Reserved for Future Use

44. COMMERCIAL SYSTEM RELIEF PROGRAM

Applicability:

Applicable to any Full Service or Retail Access Customer taking service under Service Classification Nos. 2, 3 and 13, including customers taking Standby Service under Service Classification No. 14 whose parents service classification is Service Classification No. 2, 3 or 13; and to any Aggregator that meets the requirements of this General Information Section. This program is not offered to customers participating in the Company's Targeted Demand Response program.

Contracting for Commercial System Relief Program Service:

The Commercial System Relief Program (CSRP) is applicable to Direct Participants and Aggregators who agree in writing to provide Load Relief during all Contracted Hours whenever the Company designates Planned Events during the Capability Period. Direct Participants and Aggregators may also agree to voluntarily provide Load Relief if an Unplanned Event is called.

A Direct Participant must contract to provide at least 50kW of Load Relief per enrolled account and may aggregate multiple accounts in the Company Designated Area. An Aggregator must contract to provide at least 50 kW of Load Relief.

If other requirements for service under this CSRP are met, Electric Generating Equipment may be used to participate under this CSRP subject to the provisions set forth in section A below. The participating Direct Participant or Aggregator is responsible for determining that the operation of the generating equipment under this CSRP will be in conformance with any governmental limitations on operation.

Definitions:

The following terms are defined for purposes of this CSRP only:

"Aggregator" refers to a party other than the Company that represents and aggregates the load of Customers who collectively have a Load Relief potential of 50 kW or greater in a Company Designated Area and is responsible for the actions of the Customers it represents, including performance and, as applicable, performance adjustments, and repayments to the Company.

"Capability Period" under this CSRP refers to the period during which the Company can request Load Relief. The Capability Period shall be from June 1 through September 30.

"CBL" means the customer baseline load as calculated under the Company's Customer Baseline Load methodology, using either the weather-sensitive adjustment option (the "weather adjusted CBL") or the average-day CBL. The Customer Baseline Load methodology will be described in the Company's baseline operating procedure, which will be published on the Company's website.

"CBL Verification Methodology" means the methodology used by the Company to verify the actual Load Relief provided (kW and kWh) during each hour of each designated Load Relief Period and Test Event. Actual load levels are compared to the customer baseline loads to verify whether the Direct Participant or Aggregator provided the kW of contracted Load Relief; provided, however, that the Company may estimate the data pursuant to the Company's operating procedure if data is not available for all intervals. When the weather-adjusted CBL methodology is used and the calculated weather adjustment falls outside of Company defined ranges (i.e., the Company deems the weather to be atypical on the day of a Load Relief Period or Test Event when compared to the baseline period), the Company may review and revise a participant's baseline based on the Customer's historical load data.

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

Definitions (Cont'd)

When the weather-adjusted CBL methodology is used, the Company, at its own discretion, may select alternate hours for the adjustment period to calculate the weather adjustment factor in order to accurately reflect the customer's typical usage.

"Contracted Hours" refers to the period within a weekday, Monday through Friday during the Capability Period excluding federal holidays, during which the Direct Participant or Aggregator contracts to provide Load Relief whenever the Company designates a Planned Event.

"Direct Participant" refers to a Customer who enrolls under this CSRP directly with the Company for a single Central Hudson account and agrees to provide at least 50 kW of Load Relief.

"Electric Generating Equipment" refers to: (a) electric generating equipment at the premises of a Customer that can be used to provide Load Relief under this CSRP; or (b) emergency electric generating equipment that is interconnected and can operated to provide Load Relief under this CSRP.

"Load Relief" refers to power (kW) and energy (kWh): (a) ordinarily supplied by the Company that is displaced by use of Electric Generating Equipment and/or reduced by the Direct Participant or Aggregator at the Customer's premises; or (b) produced by use of Electric Generating Equipment by a Customer and delivered by that Customer to the Company's distribution system during a Load Relief Period.

"Load Relief Period" refers to the hours for which the Company requests Load Relief when it designates a Planned Event or an Unplanned Event.

"Performance Factor," is the ratio of: (i) the average hourly kW of Load Relief provided by the Direct Participant or Aggregator during all Planned Events and Test Events which occurred during the portion of the Capability Period which the Direct Participant or Aggregator contracted to Provide Load Relief, up to the kW of contracted Load Relief to (ii) the kW of contracted Load Relief.

"Planned Event" refers to the Company's request, on not less than 21 hours' advance notice, for Load Relief during the Contracted Hours. Planned Events may be called when the Company's day-ahead forecasted load level is at least 97 percent of the forecasted summer system-wide peak.

"Renewable Generation" means behind-the-meter electric generating equipment that is not fossil-fueled and has no emissions associated with it.

"Reservation Payment Option" Direct Participants and Aggregators will receive Reservation Payment for each Capability Period month in which they are enrolled.

"Test Event" refers to the Company's request under the Reservation Payment Option for Direct Participants and Aggregators to provide one hour of Load Relief, within the span of weekday Contracted Hours, on not less than 21 hours' advance notice.

"Unplanned Event" refers to the Company's request for Load Relief: (a) on less than 21 hours' advance notice; or (b) for hours outside of the Contracted Hours. Unplanned events will only occur if the Company determines that the operational parameters of the electric system indicate a capacity need.

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44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

A. Applications and Term of Service:

Applications for service under this CSRP must be made electronically. Direct Participants and Aggregators may participate after the Company's receipt and approval of a completed application. For the summer capability period of 2016 only, customers that currently have installed interval metering and meter communications, must submit a completed application on or before May 25, 2016 for a commencement date of June 1, 2016. If the Company receives a completed application by June 15, 2016 service can commence July 1, 2016 if interval metering is installed by June 15, 2016 and meter communications are operational by June 30, 2016. Otherwise, the Company will accept applications by April 1 for a May 1 commencement date, and by May 1 for a June 1 commencement date. However, if the Company does not bill the participant monthly, using interval metering at the time of application, participation will not commence unless both interval metering and meter communications are operational. If the Company receives a completed application by April 1, service can commence May 1 if interval metering is pre-existing at the time of application and meter communications are operational by April 30. If the Company receives a completed application by May 1, service can commence on June 1 if interval metering is pre-existing at the time of application and meter communications are operational by May 31. If the application is received by May 1, but the above conditions for installation of interval metering and meter communications are not met, service will commence on July 1, provided the interval metering is installed by June 1 and meter communications are operational by June 30. Applications will not be accepted under the Reservation Payment Option after the specified date for participation during the current Capability Period.

The desired commencement month must be specified in the application.

1. Applications will not be accepted after the specified date for participation during the current Capability Period. Where the first of the month falls on a weekend or holiday, applications will be accepted until the first business day after.

2. A Direct Participant or Aggregator may apply in writing to change the CBL Verification Methodology, to change the kW of pledged Load Relief, or to terminate service under this CSRP for the upcoming Capability Period provided the request is received prior to commencing participation for that Capability Period. In order for a Direct Participant or Aggregator to increase its kW of contracted Load Relief for its existing customer(s), the Direct Participant or Aggregator's most recent Performance Factor must be no less than 1.00.

   An Aggregator may increase its kW of pledged Load Relief in a Network during a Capability Period only if it enrolls Customers whose aggregator either exits the program or is suspended from enrollment in the program for noncompliance with Aggregator eligibility requirements or the Company's operating procedures. In such case, the Aggregator may increase its kW of pledged Load Relief up to the amount of the transferred Customers' existing kW of pledged Load Relief.

3. Each application must state the kW of Load Relief that the Direct Participant or Aggregator contracts to provide for the Contracted Hours required. The weather-adjusted CBL will be used as the CBL Verification Methodology for each account number enrolled, unless the application specifies that the average-day CBL be to be used for verification of performance. A single CBL Verification Methodology will be used for each customer to assess both energy (kWh) and demand (kW) Load Relief.

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

B. Notification by the Company and Required Response:

1. The Company will notify Direct Participants and Aggregators by phone, e-mail, text, or other machine-readable electronic signal, or a combination thereof, in advance of the commencement of a Load Relief Period or Test Event. The Direct Participant or Aggregator shall designate in writing an authorized representative and an alternate representative, and include an electronic address if applicable, to receive the notice. If an Aggregator is served under this CSRP, only the Aggregator will be notified of the Load Relief Period or Test Event. The Aggregator is responsible for notifying all of the customers within its respective aggregation group.

2. If the Company designates a Planned Event or a Test Event, the Company will provide advance notice at least 21 hours in advance of the event. The Company will again provide advance notice on the day of the event, usually two or more hours in advance.

3. If the Company designates an Unplanned Event, notice will be given as soon as practicable. Participants are requested to provide Load Relief as soon as they are able.

4. Participants are required to participate during:

   a. All Contracted Hours for all Planned Events called by the Company during the Capability Period, and
   b. Test Events called by the Company. The Test Event period will not exceed one hour.

C. Metering:

1. The Direct Customer shall arrange for the furnishing and installation of interval metering with telecommunications capability. If an Aggregator takes service under this CSRP, all customers of the Aggregator must meet the metering and telecommunications requirements specified hereunder.

2. The Company will install interval metering, pending equipment availability, within 21 business days of the later of the Company's receipt of an applicant's payment for an upgrade to interval metering and the following: (i) evidence that a request has been made to the telephone carrier (e.g., receipt of a job number) to secure a dedicated phone line for a meter with landline telecommunications capability; or (ii) the active Internet Protocol ("IP") address that the wireless carrier has assigned to the modem's Electronic Serial Number ("ESN") for a meter with wireless capability. If the Company misses the installation time frame for the Reservation Payment Option, it will make a "Lost Reservation Payment" to the Direct Participant or Aggregator, unless the meter delay was caused by a reason outside the Company's control, such as the telephone company's failure to install a landline or, if, at the Company's request, the Commission grants the Company an exception due to a condition such as a major outage or storm. A Lost Reservation Payment will be calculated by determining the number of months between the earliest month in which the customer could have begun participation had the meter been installed within the required timeframe (assuming the Company's acceptance of a completed application and receipt of payment for the meter upgrade) and the first month following the completed installation, and multiplying that number by the pledged kW and associated per-kW Reservation Payment Rate.

3. Participation under this CSRP will commence the first day of the first Capability Period month that occurs after the Company's acceptance of a completed application and at least 30 days after both the interval metering and communications become operational, but no later than July 1.

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

D. Administrative Review:

The Company reserves the right to review records and/or operations of any Direct Participant, Aggregator, or customer of an Aggregator to verify enrollment information and performance associated with any designated Load Relief Period or Test Event called by the Company. Once the Company initiates a data review, all payments will be suspended pending the outcome of the review. The Company will complete its review within 30 days of receipt of all requested data, but no later than December 31 of the calendar year of the Capability Period under review. Any suspended payments will be reinstated if the Company's review of the data results in a finding that the enrollment and performance information are correct.

If the Company determines that a Direct Participant, Aggregator, or customer of an Aggregator failed to cooperate fully and promptly with the review and/or did not fully comply with the provisions of this CSRP and/or provided inaccurate data, the Direct Participant or the customer of the Aggregator will be deemed ineligible to participate in the program until the issue is rectified. In addition, the Direct Participant or Aggregator will be required to make prompt repayment to the Company of any overpayments that were made to such Direct Participant or Aggregator, on behalf of its customer, for the Capability Period that was reviewed as well as the current Capability Period, if different.

E. Aggregation:

1. All customers of an Aggregator must meet the metering and telecommunications requirements of this CSRP.

2. An Aggregator is responsible for the compliance of all customers it enrolls and will be liable for performance, including, as applicable, repayments to the Company.

F. Payments:

a. Settlement

Aggregators and direct participants will be provided one seasonal reservation and performance payment after the end of the capability period. Monthly performance reports will be provided for months in which events occurred.

Payments will be made by bill credit, check, or wire transfer at the sole discretion of the Company.

b. Reservation Payments

Direct Participants and Aggregators will receive Reservation Payment for each Capability Period month in which they are enrolled. The Reservation Payment rate per kW is based on the number of cumulative Planned Events for which the Direct Participant or Aggregator was asked to provide Load Relief during the Capability Period, as follows:

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

F. Payments (Cont'd)

The payment rate is $2.00 per kW per month in months in which, as of the last day of such month, the company asked the Direct Participant or Aggregator to provide Load Relief for four or fewer cumulative Planned Events since the current Capability Period commenced.

The payment rate is $2.50 per kW per month commencing in the month in which, as of the last day of such month, the Company asked the Direct Participant or Aggregator to provide Load Relief for five or more cumulative Planned Events since the current Capability Period commenced.

The Reservation Payment per month is equal to the applicable Reservation Payment rate per kW per month multiplied by the kW of contracted Load Relief multiplied by the Performance Factor.

c. Performance Payments for Participation in Planned Events

The Performance Payment amount paid per is equal to the Performance Payment rate of $0.15 per kWh multiplied by the Performance Factor multiplied by the contracted Load Relief multiplied by the total number of Planned Event and Test Event hours.

d. Performance Payments for Participation in Unplanned Events

A Direct Participant or Aggregator will receive payment for performance during Unplanned Events, provided the Company can verify that the Direct Participant or Aggregator provided Load Relief.

The Performance Payment amount paid per is equal to the Performance Payment rate of $0.30 per kWh multiplied by the average hourly kW of Load Relief provided during all Unplanned Events throughout the capability period multiplied by the total number of Unplanned Event hours.

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

G. Testing

The Company may require a Direct Participant or Aggregator to participate in one or more Test Events, each for a period not to exceed one hour, commencing at a time determined solely at the Company's discretion, but within the Contracted Hours.

Test event payments will be incorporated into the Reservation and Performance Payments as specified in section F.

44. COMMERCIAL SYSTEM RELIEF PROGRAM (Cont'd)

Reserved for Future Use