STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

Central Hudson Gas & Electric Corporation's Dynamic Load Management Programs Annual Report

November 14, 2025

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
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Contents

1. Background

As part of the Reforming the Energy Vision ("REV") proceeding[1], the New York Public Service Commission ("Commission") initiated the Dynamic Load Management Programs proceeding on 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 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 the evaluation.

Within both the Order Adopting Dynamic Load Management Program Changes with Modifications[5] and the Order Modifying Dynamic Load Management Filings and Making Other Findings ("The April 21st Order"),[6] the Commission directed the Utilities to make various changes to the DLM programs and report on certain additional program aspects within the respective annual reports. In the Order Adopting Program Changes with Modification and Making Other Findings, ("2018 Order")[7] the Commission set a revised annual filing date of November 15th of each year, starting in 2019.

[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* (issued December 15, 2014).
[3] Case 14-E-0423, et al., supra, *Order Adopting Dynamic Load Management Filings with Modifications* (issued June 18, 2015).
[4] Ibid, p. 7.
[5] Case 14-E-0423, Dynamic Load Management Programs, *Order Adopting Dynamic Load Management Program Changes with Modifications* (issued May 23, 2016).
[6] Case 14-E-0423, Dynamic Load Management Programs, *Order Modifying Dynamic Load Management Filings and Making Other Findings* (issued April 21, 2017).
[7] Case 14-E-0423, Dynamic Load Management Programs, *Order Adopting Program Changes with Modification and Making Other Findings* (issued April 23, 2018).

In the Order Adopting Program Changes with Modifications and Making Other Findings ("2019 Order"),[8] the Commission directed Central Hudson to retain program availability with necessary incentive rate changes to maintain the Commercial System Relief Program ("CSRP") cost-effectiveness. These changes were subsequently enacted for the 2019 program season.

The Order Establishing Energy Storage Goal and Deployment Policy ("Storage Order")[9], required utilities to develop multi-year DLM procurements, referred to as Term-DLM and Auto-DLM Programs, and to propose implementation details for the 2020 season at the time of the 2019 annual DLM report filing due November 15, 2019. A 75-day extension was requested by the Joint Utilities[10] ("JU") and granted by the Commission and on January 29, 2020, Central Hudson filed its proposal for the multi-year "term" DLM procurements.

On May 14, 2020, the Commission issued the Order Directing Demand Response Program Modifications on an Expedited Basis ("DR COVID Relief Order")[11] which directed the Joint Utilities to make certain program changes for the 2020 summer capability period in an effort to provide greater flexibility for demand response market participants in light of the COVID-19 crisis. These changes were supported by Central Hudson during the 2020 capability season.

On April 16, 2021, the Commission issued the Order Adopting Program Changes with Modifications and Making Other Findings ("DR COVID Relief with Modifications Order")[12] which directed either the retention or discontinuance for the 2021 Capability Period of temporary program changes initiated via the DR COVID Relief Order. These program modifications, discussed in more detail in Section 4: Continuation of 2020 CSRP Changes Initiated in Response to COVID-19, were supported by Central Hudson in the 2021 Capability Season.

[8] Case 14-E-0423, Dynamic Load Management Programs, *Order Adopting Program Changes with Modifications and Making Other Findings* (issued March 18, 2019) ("2019 Order").
[9] Case 18-E-0130, Energy Storage Deployment Program ("Storage Proceeding"), *Order Establishing Energy Storage Goal and Deployment Policy* (issued December 13, 2018).
[10] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the "Joint Utilities").
[11] Case 14-E-0423, et al., Dynamic Load Management Programs, *Order Directing Demand Response Program Modifications on an Expedited Basis* (issued May 14, 2020) ("DR COVID Relief Order").
[12] Case 14-E-0423 – Dynamic Load Programs, *Order Adopting Program Changes with Modifications and Making Other Findings* (issued and effective April 16, 2021) ("DR COVID Relief with Modifications Order").

On March 15, 2024, the Commission issued the Order Directing Dynamic Load Management Changes [13] ("March 15, 2024 Order") which directed Performance Payments not to be made to CSRP if service is also taken under NEM or Value-Stack tariffs, the decreasing in the CSRP event threshold from 97% to 94%, and the evaluation in efficacy of reducing the initial Performance Factor from 0.5 to 0.0. Within the Order, the Commission also directed the Joint Utilities to submit proposals for the inclusion of energy storage in their Direct Load Control Programs within their 2024 annual reports.

On May 14, 2024, the Indicated Utilities submitted a Proposal Seeking Modifications to Dynamic Load Management Program Procurement[14], with a subsequent filing[15] on July 2, 2024, proposing to modify the requirement that procurements use a sealed-bid, pay-as-bid model and allow for alternative procurement methodologies. On November 19, 2024, the Commission issued the Order Approving Modifications to Dynamic Load Management Program Procurements[16] allowing the procurement of Auto/Term DLM resources to be solicited with either a sealed-bid, pay as bid auction or a fixed, published price mechanism.

On April 25, 2025, the Commission issued the Order Addressing Dynamic Load Management Program Modifications[17] ("April 25, 2025 Order") which directed the Company to proceed with developing a Direct Load Control energy storage program, updating the Benefit Costs Analysis using the expected updated cost of service, and to file a proposal within its 2025 Annual DLM report. The April 25, 2025 Order also directed tariff amendments to clarify that customers participating in the New York Independent System Operator ("NYISO") Distributed Energy Resource Aggregation Program will not receive Performance Payments under CSRP.

[13] Case 14-E-0423 – *Order Directing Dynamic Load Program Changes* (issued and effective March 15, 2024)
[14] Case 18-E-0130 – *Indicated Utilities' Proposed Dynamic Load Management Program Procurement Mechanisms* (filed on May 14, 2024).
[15] Case 18-E-0130 – *Supplemental to the Indicated Utilities' Proposed Dynamic Load Management Program Procurement Mechanisms* (filed on July 2, 2024)
[16] Case 18-E-0130 - *Order Approving Modifications to Dynamic Load Management Program Procurements* (issued and effective November 19, 2024)
[17] Case 14-E-0423 – *Order Addressing Dynamic Load Management Program Modifications* (issued and effective April 25, 2025)

2. 2025 DLM Program Overview and Results

Overview

The Company's DLM portfolio is currently comprised solely of the CSRP. This program is available to qualifying customers anywhere in the Central Hudson service territory. Program rules and operational parameters are included within Central Hudson's Electric Tariff PSC No. 15, electric leaves 163.5.40 through 163.5.47 ("tariff").

The CSRP provides commercial and industrial customers the opportunity to earn incentives by committing to curtail load during peak periods when called upon by Central Hudson. There are two enrollment options within the CSRP, the reservation payment option and the voluntary payment option. Participants are paid incentives based on how much load reduction they provide, comprised of a monthly reservation payment, as applicable, and event performance payments. Events are dispatched when forecasted system loads reach 94% of the forecasted summer peak.

The Commission approved the cancellation of the previously offered Direct Load Control ("DLC") Program in the 2018 Order, based on findings and recommendations included within Central Hudson's 2017 Annual Report.[18]

Program Expenditures

During the 2025 season, total CSRP incentive payments made were $36,253: $23,132 in reservation payments and $13,121 in performance payments. The Company also incurred approximately $48,276 in administrative costs[19]. CSRP administrative costs are comprised of internal administration, and external costs for program implementation, evaluation, and measurement. In 2025, Term DLM programs are estimated to incur a cost of $0 for internal administration, solicitation, and bid evaluation.

A summary of the DLM expenditures from program inception to date is presented in the following table.

[18] Case 14-E-0423, Dynamic Load Management Programs, *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 2018* (filed on December 1, 2017).
[19] Actual costs from January 1, 2025 through November 1, 2025 and projected costs thereafter through to December 31, 2025.

DLM Expenditures:

DLM Programs Expenditure Summary

	2020	2021	2022	2023	2024	2025
DLC Incentives	$ -	$ -	$ -	$ -	$ -	$ -
DLC Implementation and Administration	-	-	-	-	-	-
DLC Total Expenditures	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
CSRP Incentives	$ 36,289	$ 37,826	$ 25,746	$ 14,535	$ 45,282	$ 36,253
Performance Incentives	$ 816	$ 4,424	$ 739	$ 378	$ 13,571	$ 13,121
Reservation Incentives	$ 35,473	$ 33,402	$ 25,007	$ 14,156	$ 31,711	$ 23,132
CSRP Implementation and Administration *	$ 72,784	$ 64,839	$ 49,075	$ 46,100	$ 42,171	$ 48,276
CSRP Total Expenditures	**$ 109,072**	**$ 102,665**	**$ 74,821**	**$ 60,635**	**$ 87,454**	**$ 84,529**
Standard Term DLM Contract payments	$ -	$ -	$ -	$ -	$ -	$ -
Auto Term DLM Contract payments	$ -	$ -	$ -	$ -	$ -	$ -
Term DLM Implementation and Administration	$ 18,939	$ 5,018	$ -	$ -	$ -	$ -
Term DLM Total Expenditures	**$ 18,939**	**$ 5,018**	**$ -**	**$ -**	**$ -**	**$ -**
DLM Total Expenditures	**$ 128,011**	**$ 107,683**	**$ 74,821**	**$ 60,635**	**$ 87,454**	**$ 84,529**

* 2024 Implementation and administration expenditures have been updated from the estimate of $58,277 to the actual amount incurred of $42,171

Commercial System Relief Program

In 2025, customers participated in the CSRP, all of which enrolled through an aggregator, with the exception of one customer who chose to self-aggregate. Total program enrollment was 6,712kW. Seven day-ahead system forecasts had reached 94% of the projected summer peak load. Therefore, seven events were called during the 2025 season with an average event performance of 97%.

2025 CSRP Event Details:

Date	Start Time	End Time	Enrolled kW	Actual Event Performance (Avg)	Performance Factor
6/23/2025	5:00 PM	8:00 PM	6,712	3,872	58%
6/24/2025	5:00 PM	7:00 PM	6,712	5,046	75%
6/25/2025	5:00 PM	7:00 PM	6,712	4,656	69%
7/16/2025	5:00 PM	8:00 PM	6,712	6,692	100%
7/17/2025	5:00 PM	7:00 PM	6,712	9,083	135%
7/29/2025	5:00 PM	8:00 PM	6,712	8,239	123%
7/30/2025	5:00 PM	7:00 PM	6,712	8,340	124%

The historical enrollment, performance, and number of events called since the inception of the CSRP are summarized below.

CSRP Historical Portfolio Summary

Year	Number of Participants	Number of Events *	Total Enrolled Capacity (kW)	Average Performance (kW)	Performance Factor
2015	10	0	4,103	N/A	N/A
2016	13	9	3,588	3,106	87%
2017	11	1	3,910	4,799	123%
2018	25	5	8,145	7,139	88%
2019	27	2	8,440	8,547	101%
2020	25	1	8,213	7,414	90%
2021	31	2	8,205	7,680	94%
2022	28	1	7,388	6,718	91%
2023	29	1	5,046	3,440	68%
2024	34	3	6,492	8,480	131%
2025	24	7	6,712	6,509	97%

* Includes one test event per season in 2017, 2018, 2020, 2022, and 2023.

3. Benefit Cost Analysis

Central Hudson performed a benefit cost analysis ("BCA") of the DLM programs, using the protocols outlined in Central Hudson's BCA handbook, version 4.0,[20] included in the Company's 2023 DSIP with one notable modification. Although this version of the BCA Handbook contains updated marginal avoided transmission and distribution ("T&D") infrastructure costs which are based on the "Central Hudson Gas Electric Corporation's Location Specific Avoided T&D Cost Study Report"[21] ("2018 Avoided T&D Study"), the results of this study have not been utilized for this analysis. Within the 2019 Order, the Commission stated "the Commission expects to open a new proceeding to examine statewide MCOS[22] methodologies in the near future. In the meantime, the Utilities shall continue using the existing MCOS results for designing these programs until and unless new MCOS results are adopted by the Commission."[23] As such, avoided T&D values from the "2016 T&D Study"[24], have been utilized for the purposes of this analysis. Since the 2019 Order, the Commission has opened a new proceeding[25] to examine statewide MCOS methodologies and the Company has filed its MCOS study within its 2025 DSIP, Appendix A[26]. Until the MCOS study is ruled upon, the Company plans to continue the utilization of its 2016 T&D Study.

[20] Case 16-M-0411 - In the Matter of Distributed System Implementation Plans, Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Distributed System Implementation Plan* (filed on June 30, 2023) ("DSIP").
[21] Case 15-E-0751 Value of Distributed Energy Resources, (filed on July 31, 2018).
[22] Marginal Cost of Service
[23] Case 14-E-0423, Dynamic Load Management Programs, *Order Adopting Program Changes with Modifications and Making Other Findings* (issued March 18, 2019)
[24] Case 15-E-0751 Value of Distributed Energy Resources, *Location Specific Avoided T&D Cost Study Report* (filed on June 30, 2016).
[25] Case 19-E-0238, Proceeding on Motion of Commission to Examine Utilities' Marginal Cost of Service Studies, *Order Addressing Marginal Cost of Service Studies* (issued and effective August 19, 2024).
[26] Case 16-M-0411 In the Matter of Distributed System Implementation Plans, *Distributed System Implementation Plan* (filed on June 30, 2025) ("2025 DSIP").

Benefit-Cost Results:

Event Year		2025
Events in Year		7
Avoided GCC ($/kW)	n/a	
Avoided T&D ($/kW)	$	14.55
Avoided CO2 ($/MWh)	$	34.26
Base Rate ($/kWh)	$	0.107
kW Enrolled		6,712
Performance Factor		98%

Net Participant DER Cost	$	-
Reservation Incentives	$	23,132
Performance Incentives	$	13,121
Program Administration Cost	$	48,276
Lost Utility Revenue	$	11,928
Shareholder Incentives	$	-
Total Avoided GCC ($)	$	-
Total Avoided T&D ($)	$	141,563
Total Avoided LBMP ($)	$	7,742
Total Avoided CO2 @ Utility Generator ($)	$	4,048
Total Avoided CO2 from Diesel Generation ($)	$	(1,605)
Total Avoided CO2 @ Utility Generator (lb)		69,589
Total Avoided CO2 from Diesel Generation (lb)		-43,095
Total Net CO2 Impacts (lb)		26,495

	SCT		UCT		RIM
Total Costs	$	84,529	$ 84,529	$	96,458
Total Benefits	$	153,354	$ 149,305	$	149,305
Net Benefits	$	68,824	$ 64,776	$	52,848
BC Ratio		1.81	1.77		1.55

BCA Sensitivity:

As avoided T&D value is the primary driver of benefit within the DLM programs, the BCA results are highly sensitive to this input. For informational purposes only, results associated with an alternative scenario in which the results of the 2018 Avoided T&D Study are incorporated, have been provided below.

Event Year		2025
Events in Year		7
Avoided GCC ($/kW)	n/a	
Avoided T&D ($/kW)	$	0.13
Avoided CO2 ($/MWh)	$	34.26
Base Rate ($/kWh)	$	0.107
kW Enrolled		6,712
Performance Factor		98%

Net Participant DER Cost	$	-
Reservation Incentives	$	23,132
Performance Incentives	$	13,121
Program Administration Cost	$	48,276
Lost Utility Revenue	$	11,928
Shareholder Incentives	$	-
Total Avoided GCC ($)	$	-
Total Avoided T&D ($)	$	1,236
Total Avoided LBMP ($)	$	7,742
Total Avoided CO2 @ Utility Generator ($)	$	4,048
Total Avoided CO2 from Diesel Generation ($)	$	(1,605)
Total Avoided CO2 @ Utility Generator (lb)		69,589
Total Avoided CO2 from Diesel Generation (lb)		-43,095
Total Net CO2 Impacts (lb)		26,495

	SCT	UCT	RIM
Total Costs	$ 84,529	$ 84,529	$ 96,458
Total Benefits	$ 13,026	$ 8,978	$ 8,978
Net Benefits	$ (71,503)	$ (75,551)	$ (87,480)
BC Ratio	0.15	0.11	0.09

4. Residential Battery Program Implementation Recommendation

Within the March 15, 2024 Order, the Commission directed the utilities to submit proposals outlining the specifics of the participation of residential energy storage in the Direct Load Control programs as part of the 2024 annual reports. Staff has asked that each utility consider considering four questions surrounding the implementation of a prospective residential battery program. The Company has restated Staff's questions below and followed up with our suggestions.

Question 1: How will customer performance be measured?

Response: Unlike thermostat telemetry data which only provides HVAC equipment runtime, telemetry data from residential energy storage systems (ESS) provides power output of the system, which can be used to directly measure performance, unlike thermostat telemetry data which only provides HVAC equipment runtime. This ability to directly measure ESS performance allows for demand response programs to incentivize kW delivered during Company dispatched events, rather than the percentage of events, event hours, or avoided opt-outs that are used in thermostat programs. Each customer's performance will be measured based upon their ESS output during event hours, as compared to their baseline system output during the same event window on non-event days. A customer's event performance is the average of their hourly delivered kW for each hour of the event. The seasonal performance is the average of the customer's event performance within a season. For example, if a customer delivered an average of 4 kW in Event 1, 3 kW in Event 2, and 2 kW in Event 3, their average seasonal delivered kW would be 3 kW. The baseline methodology will be made available to customers prior to or upon enrollment.

Question 2: How will customers be compensated for their participation in events?

Response: Customers will be compensated based upon their average performance across all events in a season. The average delivered kW is then multiplied by the annual per kW incentive rate. Central Hudson has conducted a preliminary benefit cost analysis that uses forecasted program costs to design a performance incentive that appropriately values customer performance while ensuring that the program can be operated cost-effectively. Central Hudson anticipates offering a meaningful incentive to encourage customer participation. As the Company conducts further analysis over the coming months,

this incentive may be revised, with the final incentive being filed no less than 60 days before the effective program launch date.

Question 3: How will Central Hudson deal with the difference in data provided by energy storage systems compared to that provided by communicating thermostats due to device telemetry, given the fact that the data available with energy storage systems creates a difference in how customer incentives for energy storage should be considered?

Response: Device telemetry from communicating thermostats measures HVAC runtime and, combined with assumptions about HVAC equipment size and efficiency, is used to estimate the power consumption of the system and event load reduction resulting from device control. In contrast, device telemetry from energy storage systems provides a much more direct view of load flexibility, including a direct measure of power output. Storage systems offer more precise and direct load control that can be more accurately measured. Due to these differences in data availability and power reduction accuracy, the Company plans to compensate storage customers as outlined in response to Question 1.

Question 4: How will Central Hudson deal with the difference between how thermostats and energy storage systems are purchased by customers (i.e., thermostats are able to be purchased and installed directly by the customer, whereas energy storage systems are costly and require professional installation)?

Response: The purchase process for thermostats and energy storage systems differs significantly and requires utilities to consider the differences in these acquisition processes when designing a program aimed at engaging customers who own or are considering the purchase of these devices. Communicating thermostats are generally purchased and installed by the customer. Once a customer buys a thermostat, they own it outright. The purchase process for energy storage systems differs significantly. Energy storage systems are much more expensive in comparison to thermostats and cannot be installed by a customer directly – they require professional installation. They may also be installed when a customer is purchasing a solar PV system. Due to the cost of these systems, energy storage systems are often not paid for in full upfront by a customer, but are financed, leased or acquired through a Power Purchase Agreement (PPA). The contractual relationships tied to energy storage systems have prompted the Company to consider allowing a customer to assign the incentive directly to their service provider. As seen from similar residential battery programs, upfront incentives such as those offered by NYSERDA that encourage customers to purchase storage systems are routinely paid directly to a service provider to reduce the customer's monthly financing or leasing costs. The same structure can be valuable for performance incentives – when a customer has financed or leased an energy storage system and earns a performance incentive from a utility program, the ability for that customer to assign the incentive directly to their energy storage service provider reduces their out-of-

pocket costs for a storage system. As an example, this approach is used by Mass Save ConnectedSolutions.

5. Residential Battery Program Launch Recommendation

Central Hudson conducted a BCA analysis of a residential battery program under two avoided cost scenarios, current vs expected, to quantify benefits. The table below summarizes the avoided cost values and sources used for each scenario. Avoided transmission costs, which reflect expected transmission fees[27], are assumed to be the same for both scenarios because transmission fees are relatively stable.

Generation capacity value ranges from the $13.32/kW-year average[28] ICAP forecast provided by DPS Staff each year for the purpose of benefit cost analysis to the $125.85/kW-year NYISO derived Cost of New Entry (CONE) for Zone G. The current avoided cost scenario is aligned with the specifications in the CHG&E Benefit Cost Analysis Handbook which have largely remained consistent since its inception in 2016. The future avoided cost scenario relies on the CONE estimates from NYISO to reflect a longer-term market equilibrium. This stands in contrast with the ICAP value, used for the current avoided cost scenario, which is more of a near-term forecast for excess capacity.

The Distribution Deferral Value ranges from the $14.55/kW-year avoided sub-transmission and distribution cost value derived consistent with the 2016 Avoided T&D Study to $13.70/kW-year 2025 Marginal Cost of Service study value from the 2025 DSIP. The current avoided cost scenario is aligned with the specifications in the CHG&E Benefit Cost Analysis Handbook which have largely remained consistent since its inception in 2016. The potential avoided cost scenario reflects the commission decision to use the 2025 MCOS to develop future avoided T&D costs.

[27]The Transmission Charge value has been updated from the previous iteration of the BCA in the 2024 DLM Annual to reflect a more realistic value closely attributed to the NYISO Transmission Service Charges: http://mis.nyiso.com/public/P-62list.htm

[28] 5 year average from 2025 to 2029

Avoided Cost Scenarios

Scenario	Benefit Description	Value	Units	Source
Potential Avoided Cost Scenario	Generation capacity value	$125.85	$/kW-year	NYISO Gross CONE, Zone G Hudson Valley, marginal resource (2-hour battery)
	Transmission charges	$0.17	$/kW-year	CHG&E NYISO Transmission Service Charge (NYCA value), assuming 50 hours of dispatch per year
	Distribution deferral Value	$13.70	$/kW-year	2025 DSIP MCOS Study Value
Current Avoided Cost Scenario	Generation capacity value	$13.32	$/kW-year	NYDPS ICAP Workbook " BCA Att A 2025 Capacity Price Forecast.xlsm"; filed 10/2025; LHV Generator ICAP prices, Multi-year average
	Transmission charges	$0.17	$/kW-year	CHG&E NYCA Transmission Service Charge Rates
	Distribution deferral Value	$14.55	$/kW-year	2016 Avoided T&D Study

The study highlighted two key conclusions provided in the table below. First, a BYOB program is expected to fall far short of cost-effectiveness under any cost perspective under the current avoided cost scenario—the enrollment levels required far surpass the total available population. The population of available participants is too small and the marginal net benefits per participant too low to break-even on non-variable costs. Second, under a future, potential avoided costs scenario break-even enrollment levels are expected to be feasible under from the societal perspectives.

Battery Site Enrollment Levels Needed for Breakeven Cost-Effectiveness

	SCT	UCT	RIM
Potential Avoided Cost Scenario	198	511	511
Current Avoided Cost Scenario	20,560	N/A	N/A

For reference, Central Hudson currently has 944 residential batteries interconnected within its service territory as of November of 2025.

N/A = Not Applicable. The marginal net benefit per participating site is negative under the UCT and RIM, therefore adding additional sites will never reach a cost-effective breakeven point.

In conclusion, the Company recommends launching a residential battery program when nearing or shortly following the realization of a future, potential avoided cost scenario, while not necessarily having to meet the same potential avoided cost value assumption outlined in this study. The cost-effectiveness of the potential scenario is largely driven by the increase in avoided generation capacity cost which is unforeseeable in the near future.

6. Term-DLM and Auto-DLM Program Procurement

Overview

Within the Storage Order, the Commission set forth requirements for utilities to develop multi-year "Term-DLM" program agreements where terms remain unchanged for a minimum of three years. Additionally, within the procurement, a separate "Auto-DLM" category would be established, requiring quicker response times, higher performance, and more stringent availability. Utilities were directed to propose implementation details for the 2020 season at the time of the 2019 annual DLM report filing due November 15, 2019.

On November 12, 2019, the Joint Utilities requested a 75-day extension[29] to the Order's directives to allow ample time to establish program designs. On November 15, 2019, the Commission responded[30], granting the request, and requiring implementation details due by January 29, 2020.

Central Hudson, along with the other Joint Utilities, filed its proposals on January 29, 2020, for procurement of these multi-year DLM procurements. The Commission's September 17, 2020 Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements and Associated Cost-Recovery ("Term and Auto DLM Order")[31] provided further guidance to program design and requires that utilities "consult with Staff to finalize on solicitation documents consistent with the directives in the Order and to issue such solicitations as soon as is practicable."[32] Prior to contract award(s), the utilities were directed to consult with Staff to ensure proper and consistent bid ceiling design. Contracted resources were to be operational and ready to provide load relief by May 1, 2021.

[29] Storage Proceeding, Extension Request of the Joint Utilities in Regard to Inclusion of Multi-year Term DLM and Premium Auto-DLM Programs for the Summer 2020 Capability Period (submitted November 12, 2019).
[30] Storage Proceeding, Ruling on Extension Request (issued November 15, 2019).
[31] Storage Proceeding, *Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements and Associated Cost-Recovery* (issued September 17, 2020) .
[32] Ibid, p.16

On October 19, 2020 the JU filed a petition[33] seeking "clarification as to whether utilities may include in their respective agreements a negative performance factor should a participant fail to provide its contractually obligated load relief as a critical operational program requirement."[34]

The Commission's March 18, 2021 Order Approving Negative Performance Factors[35] authorized the Joint Utilities to utilize negative performance factors in the Average Season Performance Factor. For the Term-DLM Program, Adjusted Performance Factors would become negative at per-event performance factors of less than 40 percent, and could reach as low as negative 80 percent. For the Auto-DLM Program, Adjusted Performance Factors would become negative at per-event performance factors of less than 45 percent, and could reach as low as negative 90 percent.[36] The authorization of allowing negative performance factors helps utilities minimize the loss of program reliability for planning purposes and provides under-performing resources an option to continue paying for under performance or electing to declare a deficiency and pay an early exit fee.

On April 1, 2021, Central Hudson filed its Implementation Plan & Compliance Filing for Term- and Auto-Dynamic Load Management Resources[37] to formalize the inclusion of negative performance factors into the program offering as directed by the Order Approving Negative Performance Factors.

Program Details

The Term-DLM and Auto-DLM programs are similar to Central Hudson's existing CSRP in that they are used for peak shaving, allow for enrollments territory-wide, require a 50kW minimum enrollment, and use the same dispatch trigger at 94% of the forecasted system peak. These multi-year resources, however, are not allowed to concurrently participate in CSRP. Additionally, Term-DLM and Auto-DLM contracted loads are bound to their contract terms, while only incremental loads may be pledged to Non-wire Alternative ("NWA") projects, should they arise.

Some key differences of the new categories compared to Central Hudson's existing CSRP are: contracts of three-year minimums; the option for a competitive, sealed, pay-as-bid procurement process; payments limited to 100% resource performance; more aggressive penalty structures, and exclusion of diesel generation resources.

[33] Storage Proceeding, *Joint Utilities Petition for Clarification of the Term-DLM and Auto-DLM Programs* (submitted October 19, 2020).
[34] Ibid, p.1
[35] Storage Proceeding, *Order Approving Negative Performance Factors* (Issued and Effective March 18, 2021)
[36] Ibid, p. 20.
[37] Storage Proceeding and Case 14-E-0423 - Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs; *Central Hudson Gas & Electric Corporation's Implementation Plan & Compliance Filing for Term- and Auto-Dynamic Load Management Resources* (filed April 1, 2021).

The Term DLM program is unique in that it will have fixed call windows of four hours (allowed to vary by location). Similar to CSRP, Term-DLM will provide a day ahead advisory notice at least 21 hours in advance of an event.

The Auto-DLM Program has the distinction of providing load relief for both peak shaving and reliability. Higher penalties exist for underperformance. It is also unique in its requirement to provide resource capacity within 10 minutes of an event being called, without previous advisory notification. The Auto-DLM category provides an 18-hour window of availability and also weekend access. Enrollment may be territory-wide or for selected locations.

2020 Solicitation and Results

Central Hudson released its Request for Proposal ("RFP") for Auto and Term-Dynamic Load Management Resources on December 9, 2020. The RFP was provided to the Company's existing CSRP aggregators as well as posted to the NYSDPS-DMM website under Cases 14-E-0423 and 18-E-0130, in the instant proceeding. Central Hudson hosted a pre-bid call for interested parties on January 8, 2021, which offered solicitation and program details, timelines, the application process, eligibility and requirements, bid evaluation, payment terms, performance calculations, penalties, and Q&A.

Following the solicitation deadline of January 15, 2021, results of the solicitation were shared with DPS Staff on February 10, 2021. Central Hudson's solicitation was provided to five recipients. Four parties indicated an intent to bid, however, only two attended the pre-bid call, and only one proposal was received. The single bid received was for Term-DLM program participation which proposed a bid price which exceeded Central Hudson's bid price ceiling. No bids were received for the Auto-DLM program. As an outcome of the solicitation results, Central Hudson did not operate an Auto- or Term-DLM program for the 2021 Capability Period.

2021 Solicitation and Results

Within the Term and Auto DLM Order, the Commission established the expectation that Auto and Term-DLM solicitations will become a regular part of DLM Program operations and that the Utilities should issue solicitations annually beginning in 2021 for participation beginning not less than 18 months from the issuance of the solicitation.[38]

During stakeholder sessions after the initial round of RFPs, stakeholders explained the difficulty of meeting overlapping RFP deadlines from the different utilities due to concurrently issued RFPs. Thus, to

[38] Term and Auto DLM Order, p. 56

facilitate broader participation in the Term- and Auto-DLM RFPs going forward, the Joint Utilities coordinated to stagger the release of their upcoming RFPs.[39]

Central Hudson released its second solicitation on December 1st of 2021 for the 2022 Capability Period. No bids were received for the Auto or Term-DLM program. As an outcome of the solicitation results, Central Hudson did not operate an Auto- or Term-DLM program for the 2022 Capability Period.

2022 Solicitation

Central Hudson released its third solicitation in December of 2022 for the 2023 Capability Period. No bids were received for the Auto or Term-DLM program. As an outcome of the solicitation results, Central Hudson did not operate an Auto- or Term-DLM program for the 2023 Capability Period.

2023 Solicitation

Central Hudson released its fourth solicitation in December of 2023 for the 2024 Capability Period. No bids were received for the Auto or Term-DLM program. As an outcome of the solicitation results, Central Hudson did not operate an Auto- or Term-DLM program for the 2024 Capability Period.

2024 Solicitation

Central Hudson released its fifth solicitation in December of 2024 for the 2025 Capability Period. The Company opted for a fixed, published-price procurement mechanism. No bids were received for the Auto or Term-DLM program. As an outcome of the solicitation results, Central Hudson did not operate an Auto- or Term-DLM program for the 2025 Capability Period.

2025 Solicitation

Central Hudson expects to release its sixth solicitation in December of 2025 for the 2026 Capability Period, opting for a fixed, published-price procurement mechanism. Results from this solicitation and Central Hudson's bid ceiling will be reviewed with Staff prior to bid award(s).

[39] Case 18-E-0130 – In the Matter of Energy Storage Deployment Program and Case 14-E-0423 – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Joint Utilities Proposed Schedule for 2023 Demand Response Capability Period (Filed September 9, 2021)

7. Conclusion

Central Hudson proposes to continue the CSRP program relatively unchanged for 2026.

Under current avoided cost assumptions, a Bring Your Own Battery (BYOB) program is not expected to achieve cost-effectiveness, as the enrollment required to break even significantly exceeds the available participant population at this time. The limited pool of available measures and low marginal net benefits per participant in a territory-wide scenario are insufficient to offset fixed costs. However, under a future avoided cost scenario, break-even enrollment may be attainable from a societal cost perspective.

As described within, future application of the MCOS studies may have a significant impact on CSRP cost effectiveness.

The results of the 2025 Auto-and Term-DLM solicitation will be reported in the 2026 Dynamic Load Management Programs Annual Report.